CVR ENERGY INC
Form 424B4
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Registration No. 333-137588
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20,000,000 Shares

CVR Energy, Inc.

Common Stock

This is an initial public offering of shares of common stock of CVR Energy, Inc. CVR Energy is offering all of the shares to be sold in the offering.

Prior to this offering, there has been no public market for the common stock. Our common stock has been approved for listing on the New York Stock Exchange under the symbol CVI.

See Risk Factors beginning on page 24 to read about factors you should consider before buying shares of the common stock.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

	Per Share	Total
Initial public offering price	$ 19.000	$ 380,000,000
Underwriting discount	$ 1.240	$ 24,800,000
Proceeds, before expenses, to us	$ 17.760	$ 355,200,000

To the extent that the underwriters sell more than 20,000,000 shares of common stock, the underwriters have the option to purchase up to an additional 3,000,000 shares from us at the initial public offering price less the underwriting discount.

The underwriters expect to deliver the shares against payment in New York, New York on October 26, 2007.

Goldman, Sachs & Co. **Deutsche Bank Securities**

Credit Suisse

Citi **Simmons & Company International**

Prospectus dated October 22, 2007.

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PROSPECTUS SUMMARY

This summary highlights selected information contained elsewhere in this prospectus. You should carefully read the entire prospectus, including the Risk Factors and the consolidated financial statements and related notes included elsewhere in this prospectus, before making an investment decision. In this prospectus, all references to the Company, Coffeyville, we, us, and our refer to CVR Energy, Inc. and its consolidated subsidiaries, unless the context otherwise requires or where otherwise indicated. References in this prospectus to the nitrogen fertilizer business refer to our nitrogen fertilizer business which, prior to the consummation of this offering, we are transferring to a newly formed limited partnership whose managing general partner will be owned by our controlling stockholders and senior management. See The Nitrogen Fertilizer Limited Partnership. You should also see the Glossary of Selected Terms beginning on page 294 for definitions of some of the terms we use to describe our business and industry. We use non-GAAP measures in this prospectus, including Net income adjusted for unrealized gain or loss from Cash Flow Swap. For a reconciliation of this measure to net income, see footnote 4 under Summary Consolidated Financial Information.

Our Business

We are an independent refiner and marketer of high value transportation fuels and, through a limited partnership, a producer of ammonia and urea ammonia nitrate, or UAN, fertilizers. We are one of only seven petroleum refiners and marketers in the Coffeyville supply area (Kansas, Oklahoma, Missouri, Nebraska and Iowa) and, at current natural gas prices, the nitrogen fertilizer business is the lowest cost producer and marketer of ammonia and UAN in North America.

Our petroleum business includes a 113,500 barrel per day, or bpd, complex full coking sour crude refinery in Coffeyville, Kansas (with capacity expected to reach approximately 115,000 bpd by the end of 2007). In addition, our supporting businesses include (1) a crude oil gathering system serving central Kansas, northern Oklahoma and southwest Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, and (3) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and to customers at throughput terminals on Magellan Midstream Partners L.P. s refined products distribution systems. In addition to rack sales (sales which are made at terminals into third party tanker trucks), we make bulk sales (sales through third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise Products Partners LP and NuStar Energy L.P. Our refinery is situated approximately 100 miles from Cushing, Oklahoma, one of the largest crude oil trading and storage hubs in the United States, served by numerous pipelines from locations including the U.S. Gulf Coast and Canada, providing us with access to virtually any crude variety in the world capable of being transported by pipeline.

The nitrogen fertilizer business is the only operation in North America that utilizes a coke gasification process to produce ammonia (based on data provided by Blue Johnson & Associates). A majority of the ammonia produced by the fertilizer plant is further upgraded to UAN fertilizer (a solution of urea, ammonium nitrate and water used as a fertilizer). By using petroleum coke, or pet coke (a coal-like substance that is produced during the refining process), instead of natural gas as raw material, at current natural gas prices the nitrogen fertilizer business is the lowest cost producer of ammonia and UAN in North America. Furthermore, on average, over 80% of the pet coke utilized by the fertilizer plant is produced and supplied to the fertilizer plant as a by-product of our refinery. As such, the nitrogen fertilizer business benefits from high natural gas prices, as fertilizer prices generally increase with natural gas prices, without a directly related change in cost (because pet coke rather than more expensive natural gas is used as a primary raw material).

We generated combined net sales of $1.7 billion, $2.4 billion, $3.0 billion and $2.7 billion and operating income of $111.2 million, $270.8 million, $281.6 million and $190.5 million for the fiscal years ended December 31, 2004, 2005 and 2006 and the twelve months ended June 30, 2007,

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respectively. Our petroleum business generated $1.6 billion, $2.3 billion, $2.9 billion and $2.6 billion of our combined net sales, respectively, over these periods, with the nitrogen fertilizer business generating substantially all of the remainder. In addition, during these periods, our petroleum business contributed $84.8 million, $199.7 million, $245.6 million and $170.5 million, respectively, of our combined operating income, with substantially all of the remainder contributed by the nitrogen fertilizer business.

Significant Milestones Since the Change of Control in June 2005

Following the acquisition by certain affiliates of The Goldman Sachs Group, Inc. (whom we collectively refer to in this prospectus as the Goldman Sachs Funds) and certain affiliates of Kelso & Company, L.P. (whom we collectively refer to in this prospectus as the Kelso Funds) in June 2005, a new senior management team was formed which has executed several key strategic initiatives that we believe have significantly enhanced our business.

Increased Refinery Throughput and Yields. Management s focus on crude slate optimization (the process of determining the most economic crude oils to be refined), reliability, technical support and operational excellence coupled with prudent expenditures on equipment has significantly improved the operating metrics of the refinery. The refinery s crude throughput rate (the volume per day processed through the refinery) has increased from an average of less than 90,000 bpd to an average of greater than 102,000 bpd in the second quarter of 2006 with peak daily rates in excess of 113,500 bpd of crude in June 2007. Crude throughputs averaged over 94,500 bpd for 2006, an improvement of more than 3,400 bpd over 2005. Recent operational improvements at the refinery have also allowed us to produce higher volumes of favorably priced distillates (primarily No. 1 diesel fuel and kerosene), premium gasoline and boutique gasoline grades.

Diversified Crude Feedstock Variety. We have expanded the variety of crude grades processed in any given month from a limited few to over a dozen. This has improved our crude purchase cost discount to West Texas Intermediate crude oil, or WTI, from $3.33 per barrel in 2005 to $4.75 per barrel in 2006.

Expanded Direct Rack Sales. We have significantly expanded and intend to continue to expand rack marketing of refined products (petroleum products such as gasoline and diesel fuel) directly to customers rather than origin bulk sales. We presently sell approximately 23% of our produced transportation fuels at enhanced margins in this manner, which has helped improve our net income for 2006 compared to 2005.

Significant Plant Improvement and Capacity Expansion Projects. Management has identified and developed several significant capital projects since June 2005 primarily aimed at (1) expanding refinery and nitrogen fertilizer plant capacity (throughput that the plants are capable of sustaining on a daily basis), (2) enhancing operating reliability and flexibility, (3) complying with more stringent environmental, health and safety standards, and (4) improving our ability to process heavier sour crude feedstock varieties (petroleum products that are processed and blended into refined products). We have completed most of these capital projects and expect to complete substantially all of the capital projects by the end of 2007. The estimated total cost of these programs is $522 million, the majority of which has already been spent.

Key Market Trends

We have identified several key factors which we believe should favorably contribute to the long-term outlook for the refining and nitrogen fertilizer industries.

For the refining industry, these factors include the following:

High capital costs, historical excess capacity and environmental regulatory requirements that have limited the construction of new refineries in the United States over the past 30 years.

Continuing improvement in the supply and demand fundamentals of the global refining industry as projected by the Energy Information Administration of the U.S. Department of Energy, or the EIA.

Increasing demand for sweet crude oils and higher incremental production of lower cost sour crude that are expected to provide a cost advantage to sour crude processing refiners.

U.S. fuel specifications, including reduced sulfur content, reduced vapor pressure and the addition of oxygenates such as ethanol, that should benefit refiners who are able to efficiently produce fuels that meet these specifications.

Limited competitive threat from foreign refiners due to sophisticated U.S. fuel specifications and increasing foreign demand for refined products.

Refining capacity shortage in the mid-continent region, as certain regional markets in the U.S. are subject to insufficient local refining capacity to meet regional demands. This should result in local refiners earning higher margins on product sales than those who must rely on pipelines and other modes of transportation for supply.

For the nitrogen fertilizer industry, these factors include the following:

The impact of a growing world population combined with an expanded use of corn for the production of ethanol both of which are expected to drive worldwide grain demand and farm production, thereby increasing demand for nitrogen-based fertilizers.

High natural gas prices in North America that contribute to higher production costs for natural gas-based U.S. ammonia producers should result in elevated nitrogen fertilizer prices, as natural gas price trends generally correlate with nitrogen fertilizer price trends (based on data provided by Blue Johnson & Associates).

However, both of our industries are cyclical and volatile and have experienced downturns in the past. See Risk Factors.

Our Competitive Strengths

Regional Advantage and Strategic Asset Location. Our refinery is one of only seven refineries located in the Coffeyville supply area within the mid-continent region, where demand for refined products exceeded refining production by approximately 22% in 2006. We estimate that this favorable supply/demand imbalance combined with our lower pipeline transportation cost as compared to the U.S. Gulf Coast refiners has allowed us to generate refining margins, as measured by the 2-1-1 crack spread, that have exceeded U.S. Gulf Coast refining margins by approximately $1.74 per barrel on average for the last four years. The 2-1-1 crack spread is a general industry standard that approximates the per barrel refining margin resulting from processing two barrels of crude oil to produce one barrel of gasoline and one barrel of diesel fuel.

In addition, the nitrogen fertilizer business is geographically advantaged to supply products to markets in Kansas, Missouri, Nebraska, Iowa, Illinois and Texas without incurring intermediate transfer, storage, barge or pipeline freight charges. Because the nitrogen fertilizer business does not incur these costs, this geographic advantage provides it with a distribution cost benefit over U.S. Gulf Coast ammonia and UAN importers, assuming in each case freight rates and pipeline tariffs for U.S. Gulf Coast importers as recently in effect.

Access to and Ability to Process Multiple Crude Oils. Since June 2005 we have significantly expanded the variety of crude grades processed in any given month. While our proximity to the Cushing crude oil trading hub minimizes the likelihood of an interruption to our supply, we intend to further diversify our sources of crude oil. Among other initiatives in this regard, we have secured shipper rights on the newly built Spearhead pipeline, which connects Chicago to the Cushing hub. We have also committed to additional pipeline capacity on the proposed Keystone pipeline

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project currently under development by TransCanada Keystone Pipeline, LP which will provide us with access to incremental oil supplies from Canada. We also own and operate a crude gathering system serving northern Oklahoma, central Kansas and southwest Nebraska, which allows us to acquire quality crudes at a discount to WTI.

High Quality, Modern Asset Base with Solid Track Record. Our refinery s complexity allows us to optimize the yields (the percentage of refined product that is produced from crude and other feedstocks) of higher value transportation fuels (gasoline and distillate), which currently account for approximately 93% of our liquid production output. Complexity is a measure of a refinery s ability to process lower quality crude in an economic manner; greater complexity makes a refinery more profitable. From 1995 through August 31, 2007, we have invested approximately $673 million to modernize our oil refinery and to meet more stringent U.S. environmental, health and safety requirements. As a result, we have achieved significant increases in our refinery crude throughput rate from an average of less than 90,000 bpd prior to June 2005 to an average of over 102,000 bpd in the second quarter of 2006 and over 94,500 bpd for 2006 with peak daily rates in excess of 113,500 bpd in June 2007. In addition, we have completed our scheduled 2007 refinery turnaround and expect that plant capacity will reach approximately 115,000 bpd by the end of 2007. The fertilizer plant, completed in 2000, is the newest fertilizer facility in North America and, since 2003, has demonstrated a consistent record of operating near full capacity. This plant underwent a scheduled turnaround in 2006, and the plant s spare gasifier was recently expanded to increase its production capacity.

Near Term Internal Expansion Opportunities. With the completion of approximately $522 million of significant capital improvements since June 2005, we expect to significantly enhance the profitability of our refinery during periods of high crack spreads while enabling the refinery to operate more profitably at lower crack spreads than is currently possible.

Unique Coke Gasification Fertilizer Plant. The nitrogen fertilizer plant is the only one of its kind in North America utilizing a coke gasification process to produce ammonia. The coke gasification process allows the plant to produce ammonia at a lower cost than natural gas-based fertilizer plants because it uses significantly less natural gas than its competitors. We estimate that the facility s production cost advantage over U.S. Gulf Coast ammonia producers is sustainable at natural gas prices as low as $2.50 per million Btu. The nitrogen fertilizer business has a secure raw material supply with an average of more than 80% of the pet coke required by the fertilizer plant historically supplied by our refinery. After this offering, we will continue to supply pet coke to the nitrogen fertilizer business pursuant to a 20-year intercompany agreement. The nitrogen fertilizer business is also considering a $50 million fertilizer plant expansion, which we estimate could increase the nitrogen fertilizer plant s capacity to upgrade ammonia into premium priced UAN by 50% to approximately 1,000,000 tons per year.

Experienced Management Team. In conjunction with the acquisition of our business by Coffeyville Acquisition LLC in June 2005, a new senior management team was formed that combined selected members of existing management with experienced new members. Our senior management team averages over 28 years of refining and fertilizer industry experience and, in coordination with our broader management team, has increased our operating income and stockholder value since the acquisition of Coffeyville Resources. Mr. John J. Lipinski, our Chief Executive Officer, has over 35 years of experience in the refining and chemicals industries, and prior to joining us in connection with the acquisition of Coffeyville Resources in June 2005, was in charge of a 550,000 bpd refining system and a multi-plant fertilizer system. Mr. Stanley A. Riemann, our Chief Operating Officer, has over 33 years of experience, and prior to joining us in March 2004, was in charge of one of the largest fertilizer manufacturing systems in the United States. Mr. James T. Rens, our Chief Financial Officer, has over 18 years of experience in the energy and fertilizer industries, and prior to joining us in March 2004, was the chief financial officer of two fertilizer manufacturing companies.

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Our Business Strategy

The primary business objectives for our refinery business are to increase value for our stockholders and to maintain our position as an independent refiner and marketer of refined fuels in our markets by maximizing the throughput and efficiency of our petroleum refining assets. In addition, management s business objectives on behalf of the nitrogen fertilizer limited partnership are to increase value for our stockholders and maximize the production and efficiency of the nitrogen fertilizer facilities. We intend to accomplish these objectives through the following strategies:

Pursuing organic expansion opportunities;

Increasing the profitability of our existing assets;

Seeking both strategic and accretive acquisitions; and

Pursuing opportunities to maximize the value of the nitrogen fertilizer limited partnership.

Nitrogen Fertilizer Limited Partnership

Prior to the consummation of this offering, we will transfer our nitrogen fertilizer business to a newly formed limited partnership, or the Partnership. The Partnership will have two general partners: a managing general partner, which we will sell at fair market value at such time to a newly formed entity owned by the Goldman Sachs Funds, the Kelso Funds and our senior management, and a second general partner, controlled by us.

We will initially own all of the interests in the Partnership (other than the managing general partner interest and associated IDRs described below) and will initially be entitled to all cash that is distributed by the Partnership. The managing general partner will not be entitled to participate in Partnership distributions except in respect of its incentive distribution rights, or IDRs, which entitle the managing general partner to receive increasing percentages of the Partnership s quarterly distributions if the Partnership increases its distributions above $0.4313 per unit. The Partnership will not make any distributions with respect to the IDRs until the aggregate adjusted operating surplus (as defined on page 241) generated by the Partnership during the period from its formation through December 31, 2009 has been distributed in respect of the interests which we hold and/or the Partnership s common and subordinated units (none of which are yet outstanding but which would be issued if the Partnership issues equity in the future). In addition, there will be no distributions paid on the managing general partner s IDRs for so long as the Partnership or its subsidiaries are guarantors under our credit facilities.

While we will initially be entitled to receive all cash that is distributed by the Partnership, the partnership agreement will provide that, once the Partnership has distributed all aggregate adjusted operating surplus generated by the Partnership during the period from its formation through December 31, 2009, the managing general partner will be entitled to receive distributions on its IDRs only after we have received a quarterly distribution of $0.4313 per unit (or $52 million per year in the aggregate) from the Partnership. This quarterly distribution amount does not represent an amount that the Partnership currently intends to distribute to us, but represents the contractual term establishing our and the managing general partner s relative right to quarterly distributions from the Partnership, subject to the other limitations set forth in the partnership agreement and described herein. This amount may be changed at the time of the Partnership s initial offering, if any. The percentage of available cash distributed by the Partnership we receive will be limited (1) if the Partnership issues common units in a public or private offering, in which event all or a portion of our interests in the Partnership will become subordinated units and the balance, if any, will become common units, (2) if we sell or are required to sell any of our special units, and (3) at such time as the managing general partner begins to receive distributions with respect to its IDRs.

The Partnership will be operated by our senior management pursuant to a services agreement to be entered into among us, the managing general partner and the Partnership. We will pay all of our senior management s compensation, and the Partnership will reimburse us for the time our senior management spends working for the Partnership. The Partnership will be managed by the managing general partner and, to the extent described below, us, as special general partner. As special general partner of the Partnership, we will have joint management rights regarding the appointment, termination and compensation of the chief executive officer and chief financial officer of the managing general partner, will designate two members of the board of directors of the managing general partner and will have joint management rights regarding specified major business decisions relating to the Partnership.

We have considered various strategic alternatives with respect to the nitrogen fertilizer business, including an initial public or private offering of limited partnership interests of the Partnership. We have observed that entities structured as publicly traded limited partnerships (also known as master limited partnerships) have over recent history demonstrated significantly greater relative market valuation levels compared to corporations in the refining and marketing sector when measured as a ratio of enterprise value to EBITDA. Following completion of this offering, any public or private offering by the Partnership would be made solely at the discretion of the Partnership s managing general partner, subject to our specified joint management rights, and would be subject to market conditions and negotiation of terms acceptable to the Partnership s managing general partner. In connection with the Partnership s initial public or private offering, if any, the Partnership may require us to include a sale of a portion of our interests in the Partnership. If the Partnership becomes a public company, we may consider a secondary offering of interests which we own. We cannot assure you that any such transaction will be consummated or that master limited partnership valuations will continue to be greater relative to market valuation levels for corporations in the refining and marketing sector.

For more detailed information about the Partnership, see The Nitrogen Fertilizer Limited Partnership.

Flood and Crude Oil Discharge

Flood. During the weekend of June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville. The river crested more than 10 feet above flood stage, setting a new record for the river. Approximately 2,000 citizens and hundreds of homes throughout the city of Coffeyville were affected. Our refinery and the nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded and were forced to conduct emergency shutdowns and evacuate.

As a result, our refinery and nitrogen fertilizer facilities sustained major damage and required extensive repairs. We hired nearly 1,000 extra contract workers to help repair and replace damaged equipment at the refinery. The refinery started operating its reformer on August 6, 2007 and began to charge crude oil to the facility on August 9, 2007. Substantially all of the refinery s units were in operation by August 20, 2007. The nitrogen fertilizer facility, situated on slightly higher ground, sustained less damage than the refinery. The nitrogen fertilizer facility initiated startup at its production facility on July 13, 2007.

The total third party cost to repair the refinery is currently estimated at approximately $86 million, and the total third party cost to repair the nitrogen fertilizer facility is currently estimated at approximately $4 million.

Crude Oil Discharge. Because the Verdigris River rose so rapidly during the flood, much faster than predicted, our employees had to shut down and secure the refinery in six to seven hours, rather than the 24 hours typically needed for such an effort. Despite our efforts to secure the refinery prior to its evacuation, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007. Crude oil was carried by floodwaters downstream from our refinery and into residential and commercial areas.

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On July 10, 2007, we entered into an administrative order on consent (the Consent Order) with the United States Environmental Protection Agency (the EPA). Pursuant to the Consent Order, we agreed to perform specified remedial actions to respond to the discharge of crude oil from our refinery. We have worked with the EPA throughout the recovery process and we could be required to reimburse the EPA s costs under the federal Oil Pollution Act. We are currently remediating the contamination caused by the crude oil discharge and expect our remedial actions to continue through December 2007. We estimate that the total costs of oil remediation through completion will be approximately $7 million to $10 million. Resolution of third party property damage claims is estimated to cost approximately $25 million to $30 million. As a result, the total cost associated with remediation and property damage claims resolution is estimated to be approximately $32 million to $40 million. This estimate does not include potential fines or penalties which may be imposed by regulatory authorities or costs arising from potential natural resource damages claims (for which we are unable to estimate a range of possible costs at this time) or possible additional damages arising from class action lawsuits related to the flood.

Impact on Our Third Quarter 2007 Performance. The flood and crude oil discharge will have a significant adverse impact on our third quarter 2007 financial results. We estimate that during the third quarter of 2007, revenue ranged between $580 million and $590 million compared to $778.6 million for the third quarter of 2006. In addition, we estimate that during the third quarter of 2007, operating income ranged between $45 million and $65 million, compared to $52.1 million for the third quarter of 2006, subject to the discussion below. The operating income range described above includes an approximately $95 million receivable due from our insurance carriers in connection with the flood and crude oil discharge. In connection with our third quarter closing process, we continue to evaluate and gather information to assess the measurement of this receivable. To the extent that we determine not to recognize some of this receivable in our third quarter financial statements, the operating income range described above will be reduced by a corresponding amount. The third quarter estimates included above are unaudited, are subject to completion, and reflect our current best estimates and may be revised as a result of management s further review of our results for the third quarter of 2007. During the course of the preparation of our final consolidated quarterly financial statements and related notes, we may identify items that would require us to make material adjustments to the preliminary financial information presented above.

We expect that we will report reduced revenue due to the closure of our facilities for a portion of the third quarter, as well as significant costs related to the flood as a result of the necessary repairs to our facilities and environmental remediation. Although operating results for the quarter ending September 30, 2007 will be significantly below historical levels due to the flood and crude oil discharge, both our refinery and nitrogen fertilizer facility have returned to operating performances at or exceeding levels achieved prior to the flood. For several days during the final weeks of September 2007, we processed in excess of 119,000 barrels per day of crude oil in our refinery. These levels of daily crude processing constitute the highest levels of daily processing ever achieved at the facility. The fertilizer plant has been back in operation since restarting production on July 13, 2007 and has demonstrated an operating performance at pre-flood levels. In addition, as of September 30, 2007, 300 of the approximately 330 residential properties that we have offered to purchase under our property repurchase program in connection with the flood and crude oil discharge are under contract. As of September 30, 2007, we had $168.1 million of borrowing availability under our credit facilities.

For more detailed information about the flood and crude oil discharge, including insurance reimbursement information, see Flood and Crude Oil Discharge.

Cash Flow Swap

In conjunction with the acquisition of our business by Coffeyville Acquisition LLC, on June 16, 2005, Coffeyville Acquisition LLC entered into a series of commodity derivative arrangements, or the Cash Flow Swap, with J. Aron & Company, or J. Aron, a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The derivative took the form of three New York Mercantile Exchange,

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or NYMEX, swap agreements whereby if crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. The Cash Flow Swap was assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005.

With crude oil capacity expected to reach 115,000 bpd by the end of 2007, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our Credit Facility and upon meeting specific requirements related to an initial public offering, our leverage ratio and our credit ratings, and assuming our other credit facilities are terminated or amended to allow such actions, we may reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010.

We entered into the Cash Flow Swap for the following reasons:

Debt was used as part of the acquisition financing in June 2005 which required the introduction of a financial risk management tool that would mitigate a portion of the inherent commodity price based volatility in our cash flow and preserve our ability to service debt; and

Given the size of the capital expenditure program contemplated by us at the time of the June 2005 acquisition, we considered it necessary to enter into a derivative arrangement to reduce the volatility of our cash flow and to ensure an appropriate return on the incremental invested capital.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current generally accepted accounting principles in the United States, or GAAP. As a result, our periodic statements of operations reflect material amounts of unrealized gains and losses based on the increases or decreases in market value of the unsettled position under the swap agreements. Given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income adjusted for unrealized gain or loss from Cash Flow Swap as a key indicator of our business performance and believes that this non-GAAP measure is a useful measure for investors in analyzing our business. For a discussion of the calculation and use of this measure, see footnote 4 to our Summary Consolidated Financial Information.

Our History

Prior to March 3, 2004, our refinery assets and the nitrogen fertilizer plant were operated as a small component of Farmland Industries, Inc., or Farmland, an agricultural cooperative. Farmland filed for bankruptcy protection on May 31, 2002. Coffeyville Resources, LLC, a subsidiary of Coffeyville Group Holdings, LLC, won the bankruptcy court auction for Farmland s petroleum business and a nitrogen fertilizer plant and completed the purchase of these assets on March 3, 2004. On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, all of the subsidiaries of Coffeyville Group Holdings, LLC were acquired by Coffeyville Acquisition LLC, an entity principally owned by the Goldman Sachs Funds and the Kelso Funds.

Prior to this offering, Coffeyville Acquisition LLC directly or indirectly owned all of our subsidiaries. We were formed as a wholly owned subsidiary of Coffeyville Acquisition LLC in order to complete this offering.

Prior to the consummation of this offering, Coffeyville Acquisition LLC will transfer half of its interests in each of Coffeyville Refining & Marketing Holdings, Inc., Coffeyville Nitrogen Fertilizers, Inc. and CVR Energy to Coffeyville Acquisition II LLC. Coffeyville Acquisition LLC will be owned by the Kelso Funds and our senior management and Coffeyville Acquisition II LLC will be owned by the Goldman Sachs Funds and our senior management.

We will then merge a newly formed direct subsidiary of ours with Coffeyville Refining & Marketing Holdings, Inc. (which owns Coffeyville Refining & Marketing, Inc.) and merge a separate newly formed direct subsidiary of ours with Coffeyville Nitrogen Fertilizers, Inc. which will make Coffeyville Refining & Marketing, Inc. and Coffeyville Nitrogen Fertilizers, Inc. wholly owned subsidiaries of ours. These transactions will result in a structure with CVR Energy below Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and above the two subsidiaries, so that CVR Energy will become the parent of the two subsidiaries. CVR Energy has not commenced operations and has no assets or liabilities. In addition, there are no contingent liabilities and commitments attributable to CVR Energy. The mergers provide a tax free means to put an appropriate organizational structure in place to go public and give CVR Energy the flexibility to simplify its structure in a tax efficient manner in the future if necessary.

In addition, we will transfer our nitrogen fertilizer business into a newly formed limited partnership and we will sell all of the interests of the managing general partner of this partnership to a new entity owned by our controlling stockholders and senior management at fair market value at such time.

We refer to these pre-IPO reorganization transactions in the prospectus as the Transactions.

Risks Relating to Our Business

We face certain risk factors that could materially affect our business, results of operations or financial condition. Our petroleum business is primarily affected by the relationship, or margin, between refined product prices and the prices for crude oil; future volatility in refining industry margins may cause volatility or a decline in our results of operations. Disruption of our ability to obtain an adequate supply of crude oil could reduce our liquidity and increase our costs.

In addition, our refinery and nitrogen fertilizer facilities face operating hazards and interruptions, including unscheduled maintenance or downtime. The nitrogen fertilizer plant has high fixed costs, and if natural gas prices fall below a certain level, our nitrogen fertilizer business may not generate sufficient revenue to operate profitably. In addition, our operations involve environmental risks that may require us to make substantial capital expenditures to remain in compliance or to remediate current or future contamination that could give rise to material liabilities. Also, we may not recover all of the costs we have incurred or expect to incur in connection with the flood and crude oil discharge that occurred at our refinery on the weekend of June 30, 2007.

The transfer of our nitrogen fertilizer business to the Partnership also involves numerous risks that could materially affect our business. The managing general partner of the Partnership will be a new entity owned by our controlling stockholders and senior management, and will manage the operations of the Partnership (subject to our specified joint management rights). The managing general partner will own incentive distribution rights which, over time, will entitle it to receive increasing percentages of quarterly distributions from the Partnership if the Partnership increases its quarterly distributions over a set amount. We will not be entitled to cash distributed in respect of the incentive distribution rights. If in the future the managing general partner decides to sell interests in the Partnership, we and you, as a stockholder of CVR Energy, will no longer have access to the cash flows of the Partnership to which the purchasers of these interests will be entitled, and at least 40% (and potentially all) of our interests will be subordinated to the interests of the new investors. In addition, the managing general partner of the Partnership will have a fiduciary duty to favor the interests of its owners, and these interests may differ from our interests and the interests of our stockholders. The members of our senior management will also face conflicts of interest because they will serve as executive officers of both CVR Energy as well as of the managing general partner of the Partnership.

For more information about these and other risks relating to our company, see Risk Factors beginning on page 24 and Cautionary Note Regarding Forward-Looking Statements beginning on page 55. You should carefully consider these risk factors together with all other information included in this prospectus.

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Organizational Structure

The following chart illustrates our organizational structure before the completion of this offering:

* Mr. John J. Lipinski, our chief executive officer, owns approximately 0.31% of Coffeyville Refining & Marketing Holdings, Inc. and approximately 0.64% of Coffeyville Nitrogen Fertilizers, Inc. It is expected that these interests will be exchanged for shares of our common stock (with an equivalent value) prior to the consummation of this offering. The mechanism for determining the equivalent value is described under Certain Relationships and Related Party Transactions Transactions with Senior Management.

The following chart illustrates our organizational structure and the organizational structure of the Partnership upon completion of this offering:

* CVR GP, LLC, which we refer to as Fertilizer GP, will be the managing general partner of CVR Partners, LP. As managing general partner, Fertilizer GP will hold incentive distribution rights, or IDRs, which will entitle the managing general partner to receive increasing percentages of the Partnership s quarterly distributions if the Partnership increases its distributions above an amount specified in the limited partnership agreement. The IDRs will only be payable after the Partnership has distributed all aggregated adjusted operating surplus (as defined on page 241) generated by the Partnership during the period from the Partnership s formation through December 31, 2009.

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The Offering

Issuer	CVR Energy, Inc.
Common stock offered by us	20,000,000 shares.
Option to purchase additional shares of common stock from us	3,000,000 shares.
Common stock outstanding immediately after the offering	83,141,291 shares.
Use of proceeds	We estimate that the net proceeds to us in this offering, after deducting the underwriters discount and the estimated expenses of the offering, will be approximately $345.20 million. We expect to use the net proceeds of this offering to repay $280 million of the term loans under our Credit Facility, and to repay all indebtedness under our $25 million unsecured facility and our $25 million secured facility. We will use the remaining net proceeds to repay indebtedness outstanding under the revolving loan facility under our Credit Facility. If the underwriters exercise their option to purchase 3,000,000 additional shares from us in full, the additional net proceeds to us would be approximately $53.28 million (and the total net proceeds to us would be approximately $398.48 million) and we intend to use such additional net proceeds in the manner described above. Any remaining net proceeds would be used for general corporate purposes. See Use of Proceeds.
Proposed New York Stock Exchange symbol	CVI.
Risk Factors	See Risk Factors beginning on page 24 of this prospectus for a discussion of factors that you should carefully consider before deciding to invest in shares of our common stock.

The number of shares of common stock to be outstanding after the offering:

- gives effect to a 628,667.20 for 1 split of our common stock;
- excludes 10,300 shares of common stock issuable upon the exercise of stock options to be granted to two directors pursuant to our long-term incentive plan on the date of this prospectus;
- excludes 17,500 shares of non-vested restricted stock to be awarded to two directors pursuant to our long-term incentive plan on the date of this prospectus;
- includes 27,100 shares of common stock to be awarded to our employees in connection with this offering; and
- assumes no exercise by the underwriters of their option to purchase up to 3,000,000 shares of common stock from us.

CVR Energy, Inc. was incorporated in Delaware in September 2006. Our principal executive offices are located at 2277 Plaza Drive, Suite 500 Sugar Land, Texas 77479, and our telephone number is (281) 207-3200. Our website address is www.CVREnergy.com. Information contained on our website is not a part of this prospectus.

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Prior to this offering, the Kelso Funds and the Goldman Sachs Funds beneficially owned substantially all of our capital stock. For further information on these entities and their relationships with us, see Certain Relationships and Related Party Transactions and The Nitrogen Fertilizer Limited Partnership.

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Summary Consolidated Financial Information

The summary consolidated financial information presented below under the caption Statement of Operations Data for the 62-day period ended March 2, 2004, for the 304-day period ended December 31, 2004, for the 174-day period ended June 23, 2005, for the 233-day period ended December 31, 2005 and for the year ended December 31, 2006, and the summary consolidated financial information presented below under the caption Balance Sheet Data as of December 31, 2005 and 2006, has been derived from our consolidated financial statements included elsewhere in this prospectus, which consolidated financial statements have been audited by KPMG LLP, independent registered public accounting firm. The summary consolidated financial information presented below under the caption Statement of Operations Data for the year ended December 31, 2003 and the summary consolidated balance sheet data as of December 31, 2003 and 2004 are derived from our audited consolidated financial statements that are not included in this prospectus. The summary unaudited interim consolidated financial information presented below under the caption Statement of Operations Data for the six-month period ended June 30, 2006 and the six-month period ended June 30, 2007, and the summary consolidated financial information presented below under the caption Balance Sheet Data as of June 30, 2007, have been derived from our unaudited interim consolidated financial statements, which are included elsewhere in this prospectus and have been prepared on the same basis as the audited consolidated financial statements. In the opinion of management, the interim data reflect all adjustments, consisting only of normal and recurring adjustments, necessary for a fair presentation of results for these periods. Operating results for the six-month period ended June 30, 2007 are not necessarily indicative of the results that may be expected for the year ended December 31, 2007. We have also included herein certain industry data.

The summary unaudited pro forma consolidated statement of operations data and other financial data for the fiscal year ended December 31, 2006 and for the six months ended June 30, 2007 give pro forma effect to the refinancing of the Credit Facility which occurred on December 28, 2006, the borrowings under the $25 million secured facility and the $25 million unsecured facility which occurred in August 2007, this offering, the use of proceeds from this offering and the Transactions, as if these transactions had occurred on January 1, 2006. The summary unaudited as adjusted consolidated financial information presented under the caption Balance Sheet Data as of June 30, 2007 gives effect to the transactions described above (other than the refinancing of the Credit Facility), the payment of a dividend to Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, the termination fee payable in connection with the termination of the management agreements with Goldman, Sachs & Co. and Kelso and Company, L.P. in conjunction with this offering and the issuance of shares of our common stock to Mr. John J. Lipinski in exchange for his shares in two of our subsidiaries in the manner described under Unaudited Pro Forma Consolidated Financial Statements, as if these transactions occurred on June 30, 2007. The summary unaudited pro forma information does not purport to represent what our results of operations would have been if these transactions had occurred as of the date indicated or what these results will be for future periods.

Prior to March 3, 2004, our assets were operated as a component of Farmland Industries, Inc. Farmland filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code on May 31, 2002. On March 3, 2004, Coffeyville Resources, LLC completed the purchase of the former Petroleum Division and one facility within the eight-plant Nitrogen Fertilizer Manufacturing and Marketing Division of Farmland (which we refer to collectively as Original Predecessor) from Farmland in a sales process under Chapter 11 of the U.S. Bankruptcy Code. See note 1 to our consolidated financial statements included elsewhere in this prospectus. We refer to this acquisition as the Initial Acquisition. As a result of certain adjustments made in connection with the Initial Acquisition, a new basis of accounting was established on the date of the Initial Acquisition and the results of operations for the 304 days ended December 31, 2004 are not comparable to prior periods.

During Original Predecessor periods, Farmland allocated certain general corporate expenses and interest expense to Original Predecessor. The allocation of these costs is not necessarily indicative of the costs that would have been incurred if Original Predecessor had operated as a

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stand-alone entity. Further, the historical results are not necessarily indicative of the results to be expected in future periods.

We calculate earnings per share for Successor on a pro forma basis, based on an assumed number of shares outstanding at the time of the initial public offering. All information in this prospectus assumes that in conjunction with the initial public offering, Coffeyville Refining & Marketing Holdings, Inc. (which owns Coffeyville Refining & Marketing, Inc.) and Coffeyville Nitrogen Fertilizers, Inc. will merge with two of our direct wholly owned subsidiaries, we will effect a 628,667.20 for 1 stock split, we will issue 247,471 shares of our common stock to our chief executive officer in exchange for his shares in two of our subsidiaries, we will issue 27,100 shares of our common stock to our employees, we will issue 17,500 shares of non-vested restricted stock to two of our directors and we will issue 20,000,000 shares of common stock in this offering. No effect has been given to any shares that might be issued in this offering by us pursuant to the exercise by the underwriters of their option.

We paid dividends for the period ended December 31, 2006 in excess of the earnings for such period. Accordingly, the earnings per share for Successor s December 31, 2006 year end and pro forma December 31, 2006 year end is calculated on a pro forma basis to give effect to the increase in the number of shares which, when multiplied by the offering price, would be sufficient to replace the capital in excess of earnings withdrawn. The weighted average number of shares outstanding for the pro forma December 31, 2006 year end also accounts for the additional $10.6 million dividend to be paid to Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Therefore, the earnings per share calculation for these periods is based upon an assumed number of shares outstanding at the time of the initial public offering increased for the additional calculated shares for the excess earnings withdrawn.

We have omitted earnings per share data for Immediate Predecessor because we operated under a different capital structure than what we will operate under at the time of this offering and, therefore, the information is not meaningful.

We have omitted per share data for Original Predecessor because, under Farmland s cooperative structure, earnings of Original Predecessor were distributed as patronage dividends to members and associate members based on the level of business conducted with Original Predecessor as opposed to a common stockholder s proportionate share of underlying equity in Original Predecessor.

Original Predecessor was not a separate legal entity, and its operating results were included with the operating results of Farmland and its subsidiaries in filing consolidated federal and state income tax returns. As a cooperative, Farmland was subject to income taxes on all income not distributed to patrons as qualifying patronage refunds and Farmland did not allocate income taxes to its divisions. As a result, Original Predecessor periods do not reflect any provision for income taxes.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. See note 1 to our consolidated financial statements included elsewhere in this prospectus. As a result of certain adjustments made in connection with this acquisition, a new basis of accounting was established on the date of the acquisition. Since the assets and liabilities of Successor and Immediate Predecessor were each presented on a new basis of accounting, the financial information for Successor, Immediate Predecessor and Original Predecessor is not comparable.

Financial data for the 2005 fiscal year is presented as the 174 days ended June 23, 2005 and the 233 days ended December 31, 2005. Successor had no financial statement activity during the period from May 13, 2005 to June 24, 2005, with the exception of certain crude oil, heating oil, and gasoline option agreements entered into with a related party as of May 16, 2005.

The historical data presented below has been derived from financial statements that have been prepared using GAAP and the pro forma data presented below has been derived from the Unaudited Pro Forma Consolidated Financial Statements included elsewhere in this prospectus. This data should be read in conjunction with the financial statements and related notes and Management s Discussion and Analysis of Financial Condition and Results of Operations included elsewhere in this prospectus.

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	Successor		Pro Forma
	Six Months Ended June 30, 2006 (unaudited)	Six Months Ended June 30, 2007 (unaudited)	Six Months Ended June 30, 2007 (unaudited)
	(in millions, except as otherwise indicated)		
Statement of Operations Data:			
Net sales	$ 1,550.6	$ 1,233.9	$ 1,233.9
Cost of product sold (exclusive of depreciation and amortization)	1,203.4	873.3	873.3
Direct operating expenses (exclusive of depreciation and amortization)	87.8	174.4	174.4
Selling, general and administrative expenses (exclusive of depreciation and amortization)	20.5	28.1	28.1
Costs associated with flood(1)		2.1	2.1
Depreciation and amortization	24.0	32.2	32.2
Operating income	$ 214.9	$ 123.8	$ 123.8
Other income	1.4	0.7	0.7
Interest (expense)	(22.3)	(27.6)	(15.9)
Loss on derivatives	(126.5)	(292.4)	(292.4)
Income (loss) before income taxes and minority interest in subsidiaries	$ 67.5	$ (195.5)	$ (183.8)
Income tax (expense) benefit	(25.7)	141.0	136.3
Minority interest in (income) loss of subsidiaries		0.2	0.2
Net income (loss)(2)	$ 41.8	$ (54.3)	$ (47.3)
Pro forma earnings (loss) per share, basic	0.50	(0.65)	(0.57)
Pro forma earnings (loss) per share, diluted	0.50	(0.65)	(0.57)
Pro forma weighted average shares, basic	83,141,291	83,141,291	83,141,291
Pro forma weighted average shares, diluted	83,158,791	83,141,291	83,141,291
Segment Financial Data:			
Operating income (loss)			
Petroleum	$ 178.0	$ 102.9	$ 102.9
Nitrogen fertilizer	37.1	21.0	21.0
Other	(0.2)	(0.1)	(0.1)
Operating income	$ 214.9	$ 123.8	$ 123.8
Depreciation and amortization			
Petroleum	$ 15.6	$ 23.1	$ 23.1
Nitrogen fertilizer	8.4	8.8	8.8
Other		0.3	0.3
Depreciation and amortization(3)	$ 24.0	$ 32.2	$ 32.2
Other Financial Data:			
	$ 101.0	$ 59.0	$ 66.0

Net income adjusted for unrealized gain or loss from Cash Flow Swap(4)		
Cash flows provided by operating activities	120.3	157.6
Cash flows (used in) investing activities	(86.2)	(214.1)
Cash flows provided by financing activities	29.0	37.6
Capital expenditures for property, plant and equipment	86.2	214.1

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	Successor	
	Six Months Ended June 30, 2006 (unaudited)	Six Months Ended June 30, 2007 (unaudited)
	(in millions, except as otherwise indicated)	
Key Operating Statistics:		
Petroleum Business		
Production (barrels per day)(5)	106,915	78,098
Crude oil throughput barrels per day(5)	94,083	71,098
Refining margin per barrel(6)	$ 15.69	$ 22.71
NYMEX 2-1-1 crack spread(7)	$ 12.02	$ 17.13
Direct operating expenses exclusive of depreciation and amortization per barrel(8)	$ 3.47	$ 10.96
Gross profit (loss) per barrel(8)	$ 11.30	$ 9.80
Nitrogen Fertilizer Business		
Production Volume:		
Ammonia (tons in thousands)	205.6	169.0
UAN (tons in thousands)	328.3	304.6
On-stream factors(9):		
Gasification	97.3%	90.6%
Ammonia	94.7%	86.8%
UAN	93.8%	81.9%

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	Original Predecessor		Immediate Predecessor		Successor	Successor	Pro Forma
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2006 (unaudited)
	(in millions, except as otherwise indicated)						
Statement of Operations Data:							
Net sales	$ 1,262.2	$ 261.1	$ 1,479.9	$ 980.7	$ 1,454.3	$ 3,037.6	$ 3,037.6
Cost of product sold (exclusive of depreciation and amortization)	1,061.9	221.4	1,244.2	768.0	1,168.1	2,443.4	2,443.4
Direct operating expenses (exclusive of depreciation and amortization)	133.1	23.4	117.0	80.9	85.3	199.0	199.0
Selling, general and administrative expenses (exclusive of depreciation and amortization)	23.6	4.7	16.3	18.4	18.4	62.6	63.5
Depreciation and amortization	3.3	0.4	2.4	1.1	24.0	51.0	51.0
Impairment, losses in joint ventures, and other charges(10)	10.9						
Operating income	$ 29.4	$ 11.2	$ 100.0	$ 112.3	$ 158.5	$ 281.6	$ 280.7
Other income (expense)(11)	(0.5)		(6.9)	(8.4)	0.4	(20.8)	(20.8)
Interest (expense)	(1.3)		(10.1)	(7.8)	(25.0)	(43.9)	(34.1)
Gain (loss) on derivatives	0.3		0.5	(7.6)	(316.1)	94.5	94.5
Income (loss) before income taxes	$ 27.9	$ 11.2	$ 83.5	$ 88.5	$ (182.2)	$ 311.4	$ 320.3
Income tax (expense) benefit			(33.8)	(36.1)	63.0	(119.8)	(123.4)

Net income (loss)(2)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ (119.2)	$ 191.6	$ 196.9
Pro forma earnings per share, basic						$ 2.22	$ 2.28
Pro forma earnings per share, diluted						2.22	2.28
Pro forma weighted average shares, basic						86,216,485	86,493,623
Pro forma weighted average shares, diluted						86,233,985	86,511,123
Segment Financial Data:							
Operating income (loss)							
Petroleum	$ 21.5	$ 7.7	$ 77.1	$ 76.7	$ 123.0	$ 245.6	245.0
Nitrogen fertilizer	7.8	3.5	22.9	35.3	35.7	36.8	36.5
Other	0.1			0.3	(0.2)	(0.8)	(0.8)
Operating income	$ 29.4	$ 11.2	$ 100.0	$ 112.3	$ 158.5	$ 281.6	280.7
Depreciation and amortization							
Petroleum	$ 2.1	$ 0.3	$ 1.5	$ 0.8	$ 15.6	$ 33.0	33.0
Nitrogen fertilizer	1.2	0.1	0.9	0.3	8.4	17.1	17.1
Other						0.9	0.9
Depreciation and amortization(3)	$ 3.3	$ 0.4	$ 2.4	$ 1.1	$ 24.0	$ 51.0	$ 51.0
Other Financial Data:							
Net income adjusted for unrealized gain or loss from Cash Flow Swap(4)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ 23.6	$ 115.4	$ 120.7
Cash flows provided by operating activities	20.3	53.2	89.8	12.7	82.5	186.6	
Cash flows (used in) investing activities	(0.8)		(130.8)	(12.3)	(730.3)	(240.2)	
Cash flows provided by (used in) financing activities	(19.5)	(53.2)	93.6	(52.4)	712.5	30.8	
Capital expenditures for property, plant and equipment	0.8		14.2	12.3	45.2	240.2	

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	Original Predecessor		Immediate Predecessor		Successor	
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006
	(in millions, except as otherwise indicated)					
Key Operating Statistics:						
Petroleum Business						
Production (barrels per day)(5)(12)	95,701	106,645	102,046	99,171	107,177	108,031
Crude oil throughput (barrels per day)(5)(12)	85,501	92,596	90,418	88,012	93,908	94,524
Refining margin per barrel(6)	$ 3.89	$ 4.23	$ 5.92	$ 9.28	$ 11.55	$ 13.27
NYMEX 2-1-1 crack spread(7)	$ 5.53	$ 6.80	$ 7.55	$ 9.60	$ 13.47	$ 10.84
Direct operating expenses exclusive of depreciation and amortization per barrel(8)	$ 2.57	$ 2.60	$ 2.66	$ 3.44	$ 3.13	$ 3.92
Gross profit per barrel(8)	$ 1.25	$ 1.57	$ 3.20	$ 5.79	$ 7.55	$ 8.39
Nitrogen Fertilizer Business						
Production Volume:						
Ammonia (tons in thousands)(12)	335.7	56.4	252.8	193.2	220.0	369.3
UAN (tons in thousands)(12)	510.6	93.4	439.2	309.9	353.4	633.1
On-stream factors(9):						
Gasification	90.1%	93.5%	92.2%	97.4%	98.7%	92.5%
Ammonia	89.6%	80.9%	79.7%	95.0%	98.3%	89.3%
UAN	81.6%	88.7%	82.2%	93.9%	94.8%	88.9%

	Original Predecessor December 31, 2003	Immediate Predecessor December 31, 2004	Successor December 31, 2005	Successor December 31, 2006	Successor Actual June 30, 2007 (unaudited)	Successor As Adjusted June 30, 2007 (unaudited)
	(in millions)					
Balance Sheet Data:						
Cash and cash equivalents	$	$ 52.7	$ 64.7	$ 41.9	$ 23.1	$ 61.1

Working capital(13)	150.5	106.6	108.0	112.3	53.5	105.3
Total assets	199.0	229.2	1,221.5	1,449.5	1,826.2	1,854.4
Liabilities subject to compromise(14)	105.2					
Total debt, including current portion		148.9	499.4	775.0	813.1	512.4
Minority interest in subsidiaries(15)				4.3	4.9	10.6
Management units subject to redemption			3.7	7.0	7.8	
Divisional/members equity	58.2	14.1	115.8	76.4	21.7	
Stockholders equity						354.6

(1) Represents the write-off of approximately $2.1 million of property, inventories and catalyst that were destroyed by the flood that occurred on June 30, 2007. See Flood and Crude Oil Discharge.

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(2) The following are certain charges and costs incurred in each of the relevant periods that are meaningful to understanding our net income and in evaluating our performance due to their unusual or infrequent nature:

	Original Predecessor		Immediate Predecessor		Successor	Successor	Pro Forma	Successor Six Months Ended June 30,		Pro Forma Six Months Ended June 30,
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2006 (unaudited)	2006 (unaudited)	2007 (unaudited)	2007 (unaudited)
	(in millions)									
Impairment of property, plant and equipment(a)	$ 9.6	$	$	$	$	$	$	$	$	$
Loss on extinguishment of debt(b)			7.2	8.1		23.4	23.4			
Inventory fair market value adjustment(c)			3.0		16.6					
Funded letter of credit expense and interest rate swap not included in interest expense(d)					2.3			0.6	0.2	0.2
Major scheduled turnaround expense(e)			1.8			6.6	6.6	0.3	76.8	76.8
Loss on termination of swap(f)					25.0					
Unrealized (gain) loss from Cash Flow Swap					235.9	(126.8)	(126.8)	98.2	188.5	188.5

(a) During the year ended December 31, 2003, we recorded an additional charge of $9.6 million related to the asset impairment of our refinery and nitrogen fertilizer plant based on the expected sales price of the assets in the Initial Acquisition.

(b) Represents the write-off of $7.2 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on May 10, 2004, the write-off of $8.1 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on June 23, 2005 and the write-off of $23.4 million in connection with the refinancing of our senior secured credit facility on December 28, 2006.

(c) Consists of the additional cost of product sold expense due to the step up to estimated fair value of certain inventories on hand at March 3, 2004 and June 24, 2005, as a result of the allocation of the purchase price of the Initial Acquisition and the Subsequent Acquisition to inventory.

(d) Consists of fees which are expensed to Selling, general and administrative expenses in connection with the funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap. We consider these fees to be equivalent to interest expense and the fees are treated as such in the calculation of EBITDA in the Credit Facility.

(e) Represents expenses associated with a major scheduled turnaround at the nitrogen fertilizer plant and our refinery.

(f) Represents the expense associated with the expiration of the crude oil, heating oil and gasoline option agreements entered into by Coffeyville Acquisition LLC in May 2005.

(3) Depreciation and amortization is comprised of the following components as excluded from cost of products sold, direct operating expense and selling, general and administrative expense:

	Original Predecessor		Immediate Predecessor		Successor			
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007
			(in millions)				(unaudited)	
Depreciation and amortization included in cost of product sold			0.2	0.1	1.1	2.2	1.0	1.2
Depreciation and amortization included in direct operating expense	3.3	0.4	2.0	0.9	22.7	47.7	22.8	30.6
Depreciation and amortization included in selling, general and administrative expense			0.2	0.1	0.2	1.1	0.2	0.4
Total depreciation and amortization	3.3	0.4	2.4	1.1	24.0	51.0	24.0	32.2

(4) Net income adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for the derivative transaction that was executed in conjunction with the Subsequent Acquisition. On June 16, 2005, Coffeyville Acquisition LLC entered into the Cash Flow Swap with J. Aron, a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The Cash Flow Swap was subsequently assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. The derivative took the form of three NYMEX swap agreements whereby if crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. With crude oil capacity expected to reach 115,000 bpd by the end of

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2007, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of the Credit Facility and upon meeting specific requirements related to an initial public offering, our leverage ratio and our credit ratings, and assuming our other credit facilities are terminated or amended to allow such actions, we may reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010. See Description of Our Indebtedness and the Cash Flow Swap.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current GAAP. As a result, our periodic statements of operations reflect in each period material amounts of unrealized gains and losses based on the increases or decreases in market value of the unsettled position under the swap agreements which is accounted for as a liability on our balance sheet. As the crack spreads increase we are required to record an increase in this liability account with a corresponding expense entry to be made to our statement of operations. Conversely, as crack spreads decline we are required to record a decrease in the swap related liability and post a corresponding income entry to our statement of operations. Because of this inverse relationship between the economic outlook for our underlying business (as represented by crack spread levels) and the income impact of the unrecognized gains and losses, and given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income adjusted for unrealized gain or loss from Cash Flow Swap as a key indicator of our business performance. In managing our business and assessing its growth and profitability from a strategic and financial planning perspective, management and our board of directors considers our U.S. GAAP net income results as well as Net income adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income adjusted for unrealized gain or loss from Cash Flow Swap enhances the understanding of our results of operations by highlighting income attributable to our ongoing operating performance exclusive of charges and income resulting from mark to market adjustments that are not necessarily indicative of the performance of our underlying business and our industry. The adjustment has been made for the unrealized loss from Cash Flow Swap net of its related tax benefit.

Net income adjusted for unrealized gain or loss from Cash Flow Swap is not a recognized term under GAAP and should not be substituted for net income as a measure of our performance but instead should be utilized as a supplemental measure of financial performance or liquidity in evaluating our business. Because Net income adjusted for unrealized gain or loss from Cash Flow Swap excludes mark to market adjustments, the measure does not reflect the fair market value of our Cash Flow Swap in our net income. As a result, the measure does not include potential cash payments that may be required to be made on the Cash Flow Swap in the future. Also, our presentation of this non-GAAP measure may not be comparable to similarly titled measures of other companies.

The following is a reconciliation of Net income adjusted for unrealized gain or loss from Cash Flow Swap to Net income:

	Original Predecessor		**Immediate Predecessor**		**Successor**	**Successor**	**Pro Forma**	**Successor**		**Pro Forma**
	Year Ended	**62 Days Ended**	**304 Days Ended**	**174 Days Ended**	**233 Days Ended**	**Year Ended**		**Six Months Ended**		**Six Months Ended**
	December 31, 2003	**March 2, 2004**	**December 31, 2004**	**June 23, 2005**	**December 31, 2005**	**December 31, 2006**	**2006**	**June 30, 2006**	**2007**	**June 30, 2007**
							(unaudited)	**(unaudited)**	**(unaudited)**	**(unaudited)**

	(in millions)									
Net income (loss) adjusted for unrealized loss from Cash Flow Swap	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ 23.6	$ 115.4	$ 120.7	$ 101.0	$ 59.0	$ 66.0
Plus: Unrealized gain (loss) from Cash Flow Swap, net of tax benefit					(142.8)	76.2	76.2	(59.2)	(113.3)	(113.3)
Net income (loss)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ (119.2)	$ 191.6	$ 196.9	$ 41.8	$ (54.3)	$ (47.3)

(5) Barrels per day is calculated by dividing the volume in the period by the number of calendar days in the period. Barrels per day as shown here is impacted by plant down-time and other plant disruptions and does not represent the capacity of the facility s continuous operations.

(6) Refining margin is a measurement calculated as the difference between net sales and cost of products sold (exclusive of deprecation and amortization) which we use as a general indication of the amount above our cost of products sold at which we are able to sell refined products. Each of the components used to calculate refining margin (net sales and cost of products sold exclusive of deprecation and amortization) can be taken directly from our statement of operations. Refining margin per barrel is a measurement calculated by dividing the refining margin by our refinery s crude oil throughput volumes for the respective periods presented. We use refining margin as the most direct and comparable metric to a crack spread which is an observable market indication of industry profitability.

Refining margin is a non-GAAP measure and should not be substituted for gross profit or operating income. Our calculations of refining margin and refining margin per barrel may differ from similar calculations of other companies in our industry, thereby limiting their usefulness as comparative measures. The table included in footnote 8 reconciles refining margin to gross profit for the periods presented.

(7) This information is industry data and is not derived from our audited financial statements or unaudited interim financial statements.

(8) Direct operating expenses (exclusive of depreciation and amortization) per throughput barrel is calculated by dividing direct operating expenses (exclusive of depreciation and amortization) by total crude oil throughput volumes for the respective periods presented. Direct operating expenses (exclusive of depreciation and amortization) includes costs associated with the actual operations of the refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance and labor and environmental compliance costs but does not include deprecation or amortization. We use direct operating expenses (exclusive of depreciation and

amortization) as a measure of operating efficiency within the plant and as a control metric for expenditures.

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Direct operating expenses (exclusive of depreciation and amortization) per refinery throughput barrel is a non-GAAP measure. Our calculations of direct operating expenses (exclusive of depreciation and amortization) per refinery throughput barrel may differ from similar calculations of other companies in our industry, thereby limiting its usefulness as a comparative measure. The following table reflects direct operating expenses (exclusive of depreciation and amortization) and the related calculation of direct operating expenses per refinery throughput barrel.

	Original Predecessor		Immediate Predecessor		Successor			
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Six Months Ended June 30, 2006 (unaudited)	Six Months Ended June 30, 2007 (unaudited)
	(in millions, except as otherwise indicated)							
Petroleum Business:								
Net sales	$ 1,161.3	$ 241.6	$ 1,390.8	$ 903.8	$ 1,363.4	$ 2,880.4	$ 1,457.7	$ 1,161.4
Cost of product sold (exclusive of depreciation and amortization)	1,040.0	217.4	1,228.1	761.7	1,156.2	2,422.7	1,190.5	869.1
Direct operating expenses (exclusive of depreciation and amortization)	80.1	14.9	73.2	52.6	56.2	135.3	59.1	141.1
Costs associated with flood								2.0
Depreciation and amortization	2.1	0.3	1.5	0.8	15.6	33.0	15.6	23.1
Gross profit (loss)	$ 39.1	$ 9.0	$ 88.0	$ 88.7	$ 135.4	$ 289.4	$ 192.5	$ 126.1
Plus direct operating expenses (exclusive of depreciation and amortization)	80.1	14.9	73.2	52.6	56.2	135.3	59.1	141.1
Plus costs associated with flood								2.0
Plus depreciation and amortization	2.1	0.3	1.5	0.8	15.6	33.0	15.6	23.1
Refining margin	$ 121.3	$ 24.2	$ 162.7	$ 142.1	$ 207.2	$ 457.7	$ 267.2	$ 292.3
Refining margin per refinery throughput barrel	$ 3.89	$ 4.23	$ 5.92	$ 9.28	$ 11.55	$ 13.27	$ 15.69	$ 22.71
Gross profit (loss) per refinery throughput	$ 1.25	$ 1.57	$ 3.20	$ 5.79	$ 7.55	$ 8.39	$ 11.30	$ 9.80

barrel																
Direct operating expenses (exclusive of depreciation and amortization) per refinery throughput barrel	$	2.57	$	2.60	$	2.66	$	3.44	$	3.13	$	3.92	$	3.47	$	10.96

(9) On-stream factor is the total number of hours operated divided by the total number of hours in the reporting period.

(10) During the year ended December 31, 2003, we recorded an additional charge of $9.6 million related to the asset impairment of the refinery and nitrogen fertilizer plant based on the expected sales price of the assets in the Initial Acquisition. In addition, we recorded a charge of $1.3 million for the rejection of existing contracts while operating under Chapter 11 of the U.S. Bankruptcy Code.

(11) During the 304 days ended December 31, 2004, the 174 days ended June 23, 2005 and the year ended December 31, 2006, we recognized a loss of $7.2 million, $8.1 million and $23.4 million, respectively, on early extinguishment of debt.

(12) Operational information reflected for the 233-day Successor period ended December 31, 2005 includes only 191 days of operational activity. Successor was formed on May 13, 2005 but had no financial statement activity during the 42-day period from May 13, 2005 to June 24, 2005, with the exception of certain crude oil, heating oil and gasoline option agreements entered into with J. Aron as of May 16, 2005 which expired unexercised on June 16, 2005.

(13) Excludes liabilities subject to compromise due to Original Predecessor s bankruptcy of $105.2 million as of December 31, 2003 in calculating Original Predecessor s working capital.

(14) While operating under Chapter 11 of the U.S. Bankruptcy Code, Original Predecessor s financial statements were prepared in accordance with SOP 90-7 Financial Reporting by Entities in Reorganization under Bankruptcy Code. SOP 90-7 requires that pre-petition liabilities be segregated in the Balance Sheet.

(15) Minority interest reflects (a) on December 31, 2006 and June 30, 2007, respectively, common stock in two of our subsidiaries owned by John J. Lipinski (which will be exchanged for shares of our common stock with an equivalent value prior to the consummation of this offering) and (b) on June 30, 2007, as adjusted, the managing general partner interest in the Partnership held by our controlling stockholders and senior management.

About This Prospectus

Certain Definitions

In this prospectus,

Original Predecessor refers to the former Petroleum Division and one facility within the eight-plant Nitrogen Fertilizer Manufacturing and Marketing Division of Farmland which Coffeyville Resources, LLC acquired on March 3, 2004 in a sales process under Chapter 11 of the U.S. Bankruptcy Code;

Initial Acquisition refers to the acquisition of Original Predecessor on March 3, 2004 by Coffeyville Resources, LLC;

Immediate Predecessor refers to Coffeyville Group Holdings, LLC and its subsidiaries, including Coffeyville Resources, LLC;

Subsequent Acquisition refers to the acquisition of Immediate Predecessor on June 24, 2005 by Coffeyville Acquisition LLC; and

Successor refers to Coffeyville Acquisition LLC and its consolidated subsidiaries.

In addition, references in this prospectus to the nitrogen fertilizer business refer to our nitrogen fertilizer business which, prior to the consummation of this offering, we are transferring to a newly formed limited partnership. The managing general partner of the limited partnership will be a new entity owned by our controlling stockholders and senior management. We will initially own all of the interests in the limited partnership (other than the managing general partner interest and associated IDRs). See The Nitrogen Fertilizer Limited Partnership.

Industry and Market Data

The data included in this prospectus regarding the oil refining industry and the nitrogen fertilizer industry, including trends in the market and our position and the position of our competitors within these industries, are based on our estimates, which have been derived from management s knowledge and experience in the areas in which the relevant businesses operate, and information obtained from customers, distributors, suppliers, trade and business organizations, internal research, publicly available information, industry publications and surveys and other contacts in the areas in which the relevant businesses operate. We have also cited information compiled by industry publications, governmental agencies and publicly available sources. Although we believe that these sources are generally reliable, we have not independently verified data from these sources or obtained third party verification of this data. Estimates of market size and relative positions in a market are difficult to develop and inherently uncertain. Accordingly, investors should not place undue weight on the industry and market share data presented in this prospectus.

Trademarks, Trade Names and Service Marks

This prospectus includes trademarks, including COFFEYVILLE RESOURCES™ and CVR Energy™, and we have applied for federal registration of these trademarks. This prospectus also contains trademarks, service marks, copyrights and trade names of other companies.

RISK FACTORS

You should carefully consider each of the following risks and all of the information set forth in this prospectus before deciding to invest in our common stock. If any of the following risks and uncertainties develops into actual events, our business, financial condition or results of operations could be materially adversely affected. In that case, the price of our common stock could decline and you could lose part or all of your investment.

Risks Related to Our Petroleum Business

Volatile margins in the refining industry may cause volatility or a decline in our future results of operations and decrease our cash flow.

Our petroleum business financial results are primarily affected by the relationship, or margin, between refined product prices and the prices for crude oil and other feedstocks. Future volatility in refining industry margins may cause volatility or a decline in our results of operations, since the margin between refined product prices and feedstock prices may decrease below the amount needed for us to generate net cash flow sufficient for our needs. Although an increase or decrease in the price for crude oil generally results in a similar increase or decrease in prices for refined products, there is normally a time lag in the realization of the similar increase or decrease in prices for refined products. The effect of changes in crude oil prices on our results of operations therefore depends in part on how quickly and how fully refined product prices adjust to reflect these changes. A substantial or prolonged increase in crude oil prices without a corresponding increase in refined product prices, or a substantial or prolonged decrease in refined product prices without a corresponding decrease in crude oil prices, could have a significant negative impact on our earnings, results of operations and cash flows.

If we are required to obtain our crude oil supply without the benefit of our credit intermediation agreement, our exposure to the risks associated with volatile crude prices may increase and our liquidity may be reduced.

We currently obtain the majority of our crude oil supply through a crude oil credit intermediation agreement with J. Aron, which minimizes the amount of in transit inventory and mitigates crude pricing risks by ensuring pricing takes place extremely close to the time when the crude is refined and the yielded products are sold. In the event this agreement is terminated or is not renewed prior to expiration we may be unable to obtain similar services from another party at the same or better terms as our existing agreement. The current credit intermediation agreement expires on December 31, 2007. Further, if we were required to obtain our crude oil supply without the benefit of an intermediation agreement, our exposure to crude pricing risks may increase, even despite any hedging activity in which we may engage, and our liquidity would be negatively impacted due to the increased inventory and the negative impact of market volatility.

Disruption of our ability to obtain an adequate supply of crude oil could reduce our liquidity and increase our costs.

Our refinery requires approximately 80,000 bpd of crude oil in addition to the light sweet crude oil we gather locally in Kansas and northern Oklahoma. We obtain a significant amount of our non-gathered crude oil, approximately 20% to 30% on average, from Latin America and South America. If these supplies become unavailable to us, we may need to seek supplies from the Middle East, West Africa, Canada and the North Sea. We are subject to the political, geographic, and economic risks attendant to doing business with suppliers located in those regions. Disruption of production in any of such regions for any reason could have a material impact on other regions and our business. In the event that one or more of our traditional suppliers becomes unavailable to us, we may be unable to obtain an adequate supply of crude oil, or we may only be able to obtain our crude oil supply at

unfavorable prices. As a result, we may experience a reduction in our liquidity and our results of operations could be materially adversely affected.

The key event of 2005 in our industry was the hurricane season which produced a record number of named storms, including hurricanes Katrina and Rita. The location and intensity of these storms caused extreme amounts of damage to both crude and natural gas production as well as extensive disruption to many U.S. Gulf Coast refinery operations although we believe that substantially most of this refining capacity has been restored. These events caused both price spikes in the commodity markets as well as substantial increases in crack spreads. Severe weather, including hurricanes along the U.S. Gulf Coast, could interrupt our supply of crude oil. Supplies of crude oil to our refinery are periodically shipped from U.S. Gulf Coast production or terminal facilities, including through the Seaway Pipeline from the U.S. Gulf Coast to Cushing, Oklahoma. U.S. Gulf Coast facilities could be subject to damage or production interruption from hurricanes or other severe weather in the future which could interrupt or materially adversely affect our crude oil supply. If our supply of crude oil is interrupted, our business, financial condition and results of operations could be materially adversely impacted.

Our profitability is linked to the light/heavy and sweet/sour crude oil price spreads. In 2005 and 2006 the light/heavy crude oil price spread increased significantly. A decrease in either of the spreads would negatively impact our profitability.

Our profitability is linked to the price spreads between light and heavy crude oil and sweet and sour crude oil within our plant capabilities. We prefer to refine heavier sour crude oils because they have historically provided wider refining margins than light sweet crude. Accordingly, any tightening of the light/heavy or sweet/sour spreads could reduce our profitability. During 2005 and 2006, relatively high demand for lighter sweet crude due to increasing demand for more highly refined fuels resulted in an attractive light/heavy crude oil price spread and an improved sweet/sour spread compared to 2004. Countries with less complex refining capacity than the United States and Europe continue to require large volumes of light sweet crude in order to meet their demand for transportation fuels. Crude oil prices may not remain at current levels and the light/heavy or sweet/sour spread may decline, which could result in a decline in profitability or operating losses.

The new and redesigned equipment in our facilities may not perform according to expectations, which may cause unexpected maintenance and downtime and could have a negative effect on our future results of operations and financial condition.

We have recently upgraded all of the units in our refinery by installing new equipment and redesigning older equipment to improve refinery capacity. The installation and redesign of key equipment involves significant risks and uncertainties, including the following:

- our upgraded equipment may not perform at expected throughput levels;
- the yield and product quality of new equipment may differ from design; and
- redesign or modification of the equipment may be required to correct equipment that does not perform as expected, which could require facility shutdowns until the equipment has been redesigned or modified.

We have also repaired certain of our equipment as a result of the flood. This repaired equipment is subject to similar risks and uncertainties as described above. Any of these risks associated with new equipment, redesigned older equipment, or repaired equipment could lead to lower revenues or higher costs or otherwise have a negative impact on our future results of operations and financial condition.

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If our access to the pipelines on which we rely for the supply of our feedstock and the distribution of our products is interrupted, our inventory and costs may increase and we may be unable to efficiently distribute our products.

If one of the pipelines on which we rely for supply of our crude oil becomes inoperative, we would be required to obtain crude oil for our refinery through an alternative pipeline or from additional tanker trucks, which could increase our costs and result in lower production levels and profitability. Similarly, if a major refined fuels pipeline becomes inoperative, we would be required to keep refined fuels in inventory or supply refined fuels to our customers through an alternative pipeline or by additional tanker trucks from the refinery, which could increase our costs and result in a decline in profitability.

Our petroleum business financial results are seasonal and generally lower in the first and fourth quarters of the year, which may cause volatility in the price of our common stock.

Demand for gasoline products is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic and road construction work. As a result, our results of operations for the first and fourth calendar quarters are generally lower than for those for the second and third quarters, which may cause volatility in the price of our common stock. Further, reduced agricultural work during the winter months somewhat depresses demand for diesel fuel in the winter months. In addition to the overall seasonality of our business, unseasonably cool weather in the summer months and/or unseasonably warm weather in the winter months in the markets in which we sell our petroleum products could have the effect of reducing demand for gasoline and diesel fuel which could result in lower prices and reduce operating margins.

We face significant competition, both within and outside of our industry. Competitors who produce their own supply of feedstocks, have extensive retail outlets, make alternative fuels or have greater financial resources than we do may have a competitive advantage over us.

The refining industry is highly competitive with respect to both feedstock supply and refined product markets. We may be unable to compete effectively with our competitors within and outside of our industry, which could result in reduced profitability. We compete with numerous other companies for available supplies of crude oil and other feedstocks and for outlets for our refined products. We are not engaged in the petroleum exploration and production business and therefore we do not produce any of our crude oil feedstocks. We do not have a retail business and therefore are dependent upon others for outlets for our refined products. We do not have any long-term arrangements for much of our output. Many of our competitors in the United States as a whole, and one of our regional competitors, obtain significant portions of their feedstocks from company-owned production and have extensive retail outlets. Competitors that have their own production or extensive retail outlets with brand-name recognition are at times able to offset losses from refining operations with profits from producing or retailing operations, and may be better positioned to withstand periods of depressed refining margins or feedstock shortages. A number of our competitors also have materially greater financial and other resources than us, providing them the ability to add incremental capacity in environments of high crack spreads. These competitors have a greater ability to bear the economic risks inherent in all phases of the refining industry. An expansion or upgrade of our competitors facilities, price volatility, international political and economic developments and other factors are likely to continue to play an important role in refining industry economics and may add additional competitive pressure on us. In addition, we compete with other industries that provide alternative means to satisfy the energy and fuel requirements of our industrial, commercial and individual consumers. The more successful these alternatives become as a result of governmental regulations, technological advances, consumer demand, improved pricing or otherwise, the greater the impact on pricing and demand for our products and our profitability. There are presently significant governmental and consumer pressures to increase the use of alternative fuels in the United States.

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Environmental laws and regulations will require us to make substantial capital expenditures in the future.

Current or future federal, state and local environmental laws and regulations could cause us to expend substantial amounts to install controls or make operational changes to comply with environmental requirements. In addition, future environmental laws and regulations, or new interpretations of existing laws or regulations, could limit our ability to market and sell our products to end users. Any such future environmental laws or governmental regulations could have a material impact on the results of our operations.

In March 2004, we entered into a Consent Decree with the United States Environmental Protection Agency, or the EPA, and the Kansas Department of Health and Environment, or the KDHE, to address certain allegations of Clean Air Act violations by Farmland at the Coffeyville oil refinery in order to reduce environmental risks and liabilities going forward. Pursuant to the Consent Decree, in the short-term, we have increased the use of catalyst additives to the fluid catalytic cracking unit at the facility to reduce emissions of sulfur dioxide, or SO_2. We will begin adding catalyst to reduce oxides of nitrogen, or NOx, in 2007. A catalyst is a substance that alters, accelerates or instigates chemical changes, but is neither produced, consumed nor altered in the process. In the long term, we will install controls to minimize both SO_2 and NOx emissions, which under the terms of the Consent Decree require that final controls be in place by January 1, 2011. In addition, pursuant to the Consent Decree, we assumed certain cleanup obligations at our Coffeyville refinery and Phillipsburg terminal, and we agreed to retrofit some heaters at the refinery with Ultra Low NOx burners. All heater retrofits have been performed and we are currently verifying that the heaters meet the Ultra Low NOx standards required by the Consent Decree. The Ultra Low NOx heater technology is in widespread use throughout the industry. There are other permitting, monitoring, recordkeeping and reporting requirements associated with the Consent Decree, and we are required to provide periodic reports on our compliance with the terms and conditions of the Consent Decree. The overall costs of complying with the Consent Decree over the next four years are expected to be approximately $41 million. To date, we have met all deadlines and requirements of the Consent Decree and we have not had to pay any stipulated penalties, which are required to be paid for failure to comply with various terms and conditions of the Consent Decree. Availability of equipment and technology performance, as well as EPA interpretations of provisions of the Consent Decree that differ from ours, could have a material adverse effect on our ability to meet the requirements imposed by the Consent Decree.

We will incur capital expenditures over the next several years in order to comply with regulations under the Clean Air Act establishing stringent low sulfur content specifications for our petroleum products, including the Tier II gasoline standards, as well as regulations with respect to on- and off-road diesel fuel, which are designed to reduce air emissions from the use of these products. In February 2004, the EPA granted us a hardship waiver, which will require us to meet final low sulfur Tier II gasoline standards by January 1, 2011. Compliance with the Tier II gasoline standards and on-road diesel standards required us to spend approximately $133 million during 2006 and we estimate that compliance will require us to spend approximately $108 million in 2007 and approximately $57 million between 2008 and 2010. Changes in these laws or interpretations thereof could result in significantly greater expenditures.

On July 10, 2007, we entered into the Consent Order with the EPA. As set forth in the Consent Order, the EPA concluded that the discharge of oil from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007 caused and may continue to cause an imminent and substantial threat to the public health and welfare. Pursuant to the Consent Order, we agreed to perform specific remedial actions to respond to the discharge of crude oil from our refinery. Additionally, we could be required to reimburse the EPA s costs under the federal Oil Pollution Act. See Flood and Crude Oil Discharge EPA Administrative Order on Consent.

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Changes in our credit profile may affect our relationship with our suppliers, which could have a material adverse effect on our liquidity.

Changes in our credit profile may affect the way crude oil suppliers view our ability to make payments and may induce them to shorten the payment terms of their invoices. Given the large dollar amounts and volume of our feedstock purchases, a change in payment terms may have a material adverse effect on our liquidity and our ability to make payments to our suppliers.

We may have additional capital needs for which our internally generated cash flows and other sources of liquidity may not be adequate.

If we cannot generate cash flow or otherwise secure sufficient liquidity to support our short-term and long-term capital requirements, we may be unable to comply with certain environmental standards or pursue our business strategies, in which case our operations may not perform as well as we currently expect. We have substantial short-term and long-term capital needs, including capital expenditures we are required to make to comply with Tier II gasoline standards, on-road diesel regulations, off-road diesel regulations and the Consent Decree. Our short-term working capital needs are primarily crude oil purchase requirements, which fluctuate with the pricing and sourcing of crude oil. We also have significant long-term needs for cash, including deferred payments owed under the Cash Flow Swap and debt repayment obligations. We currently estimate that mandatory capital and turnaround expenditures, excluding the non-recurring capital expenditures required to comply with Tier II gasoline standards, on-road diesel regulations, off-road diesel regulations and the Consent Decree described above, will average approximately $64 million per year over the next five years.

Risks Related to the Nitrogen Fertilizer Business

The nitrogen fertilizer plant has high fixed costs. If natural gas prices fall below a certain level, the nitrogen fertilizer business may not generate sufficient revenue to operate profitably or cover its costs.

The nitrogen fertilizer plant has high fixed costs as discussed in Management s Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting Results Nitrogen Fertilizer Business. As a result, downtime or low productivity due to reduced demand, weather interruptions, equipment failures, low prices for fertilizer products or other causes can result in significant operating losses. Unlike its competitors, whose primary costs are related to the purchase of natural gas and whose fixed costs are minimal, the nitrogen fertilizer business has high fixed costs not dependent on the price of natural gas. A decline in natural gas prices generally has the effect of reducing the base sale price for fertilizer products while other fixed costs remain substantially the same. Any decline in the price of fertilizer products could have a material negative impact on our profitability and results of operations.

The nitrogen fertilizer business is cyclical, which exposes us to potentially significant fluctuations in our financial condition and results of operations, which could result in volatility in the price of our common stock.

A significant portion of nitrogen fertilizer product sales consists of sales of agricultural commodity products, exposing us to fluctuations in supply and demand in the agricultural industry. These fluctuations historically have had and could in the future have significant effects on prices across all nitrogen fertilizer products and, in turn, the nitrogen fertilizer business results of operations and financial condition, which could result in significant volatility in the price of our common stock. The prices of nitrogen fertilizer products depend on a number of factors, including general economic conditions, cyclical trends in end-user markets, supply and demand imbalances, and weather conditions, which have a greater relevance because of the seasonal nature of fertilizer application. Changes in supply result from capacity additions or reductions and from changes in inventory levels. Demand for fertilizer products is dependent, in part, on demand for crop nutrients by the global agricultural industry. Periods of high demand, high capacity utilization, and increasing operating margins have tended to result in new

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plant investment and increased production until supply exceeds demand, followed by periods of declining prices and declining capacity utilization until the cycle is repeated.

Fertilizer products are global commodities, and the nitrogen fertilizer business faces intense competition from other nitrogen fertilizer producers.

The nitrogen fertilizer business is subject to intense price competition from both U.S. and foreign sources, including competitors operating in the Persian Gulf, Asia-Pacific, the Caribbean and the former Soviet Union. Fertilizers are global commodities, with little or no product differentiation, and customers make their purchasing decisions principally on the basis of delivered price and availability of the product. The nitrogen fertilizer business competes with a number of U.S. producers and producers in other countries, including state-owned and government-subsidized entities. The United States and the European Commission each have trade regulatory measures in effect which are designed to address this type of unfair trade. Changes in these measures could have an adverse impact on the sales and profitability of the particular products involved. Some competitors have greater total resources and are less dependent on earnings from fertilizer sales, which makes them less vulnerable to industry downturns and better positioned to pursue new expansion and development opportunities. In addition, recent consolidation in the fertilizer industry has increased the resources of several competitors. In light of this industry consolidation, our competitive position could suffer to the extent the nitrogen fertilizer business is not able to expand its own resources either through investments in new or existing operations or through acquisitions, joint ventures or partnerships. An inability to compete successfully could result in the loss of customers, which could adversely affect our sales and profitability.

Adverse weather conditions during peak fertilizer application periods may have a negative effect upon our results of operations and financial condition, as the nitrogen fertilizer business agricultural customers are geographically concentrated.

Sales of fertilizer products by the nitrogen fertilizer business to agricultural customers are concentrated in the Great Plains and Midwest states and are seasonal in nature. For example, the nitrogen fertilizer business generates greater net sales and operating income in the spring. Accordingly, an adverse weather pattern affecting agriculture in these regions or during this season could have a negative effect on fertilizer demand, which could, in turn, result in a decline in our net sales, lower margins and otherwise negatively affect our financial condition and results of operations. Our quarterly results may vary significantly from one year to the next due primarily to weather-related shifts in planting schedules and purchase patterns, as well as the relationship between natural gas and nitrogen fertilizer product prices.

Our margins and results of operations may be adversely affected by the supply and price levels of pet coke and other essential raw materials.

Pet coke is a key raw material used by the nitrogen fertilizer business in the manufacture of nitrogen fertilizer products. Increases in the price of pet coke could result in a decrease in our profit margins or results of operations. Our profitability is directly affected by the price and availability of pet coke obtained from our oil refinery and purchased from third parties. The nitrogen fertilizer business obtains the majority of the pet coke it needs from our adjacent oil refinery, and procures the remainder on the open market. The nitrogen fertilizer business is therefore sensitive to fluctuations in the price of pet coke on the open market. Pet coke prices could significantly increase in the future. In addition, the BOC air separation plant that provides oxygen, nitrogen, and compressed dry air to the nitrogen fertilizer plant s gasifier has experienced numerous short-term interruptions (one to five minute), thereby causing interruptions in the gasifier operations. The operations of the nitrogen fertilizer business require a reliable supply of raw materials. A disruption of its reliable supply could prevent it from producing its products at current levels and its reputation, customer relationships and results of operations could be materially harmed.

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The nitrogen fertilizer business may not be able to maintain an adequate supply of pet coke and other essential raw materials. In addition, the nitrogen fertilizer business could experience production delays or cost increases if alternative sources of supply prove to be more expensive or difficult to obtain. If raw material costs were to increase, or if the fertilizer plant were to experience an extended interruption in the supply of raw materials, including pet coke, to its production facilities, the nitrogen fertilizer business could lose sale opportunities, damage its relationships with or lose customers, suffer lower margins, and experience other negative effects to its business, results of operations and financial condition. In addition, if natural gas prices in the United States were to decline to a level that prompts those U.S. producers who have permanently or temporarily closed production facilities to resume fertilizer production, this would likely contribute to a global supply/demand imbalance that could negatively affect our margins, results of operations and financial condition.

Ammonia can be very volatile. If we are held liable for accidents involving ammonia that cause severe damage to property and/or injury to the environment and human health, our financial condition and the price of our common stock could decline. In addition, the costs of transporting ammonia could increase significantly in the future.

The nitrogen fertilizer business manufactures, processes, stores, handles, distributes and transports ammonia, which is very volatile. Accidents, releases or mishandling involving ammonia could cause severe damage or injury to property, the environment and human health, as well as a possible disruption of supplies and markets. Such an event could result in civil lawsuits and regulatory enforcement proceedings, both of which could lead to significant liabilities. Any damage to persons, equipment or property or other disruption of the ability of the nitrogen fertilizer business to produce or distribute its products could result in a significant decrease in operating revenues and significant additional cost to replace or repair and insure its assets, which could negatively affect our operating results and financial condition. In addition, the nitrogen fertilizer business may incur significant losses or costs relating to the operation of railcars used for the purpose of carrying various products, including ammonia. Due to the dangerous and potentially toxic nature of the cargo, in particular ammonia on board railcars, a railcar accident may result in uncontrolled or catastrophic circumstances, including fires, explosions, and pollution. These circumstances may result in severe damage and/or injury to property, the environment and human health. In the event of pollution, we may be strictly liable. If we are strictly liable, we could be held responsible even if we are not at fault and we complied with the laws and regulations in effect at the time. Litigation arising from accidents involving ammonia may result in our being named as a defendant in lawsuits asserting claims for large amounts of damages, which could have a material adverse effect on our financial condition and the price of our common stock.

Given the risks inherent in transporting ammonia, the costs of transporting ammonia could increase significantly in the future. Ammonia is most typically transported by railcar. A number of initiatives are underway in the railroad and chemicals industries which may result in changes to railcar design in order to minimize railway accidents involving hazardous materials. If any such design changes are implemented, or if accidents involving hazardous freight increases the insurance and other costs of railcars, freight costs of the nitrogen fertilizer business could significantly increase.

Environmental laws and regulations could require the nitrogen fertilizer business to make substantial capital expenditures in the future.

The nitrogen fertilizer business manufactures, processes, stores, handles, distributes and transports fertilizer products, including ammonia, that are subject to federal, state and local environmental laws and regulations. Presently existing or future environmental laws and regulations could cause the nitrogen fertilizer business to expend substantial amounts to install controls or make operational changes to comply with changes in environmental requirements. In addition, future environmental laws and regulations, or new interpretations of existing laws or regulations, could limit the ability of the nitrogen fertilizer business to market and sell its products to end users. Any such future environmental laws or governmental regulations may have a significant impact on our results of operations.

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The nitrogen fertilizer operations are dependent on a few third-party suppliers. Failure by key third-party suppliers of oxygen, nitrogen and electricity to perform in accordance with their contractual obligations may have a negative effect upon our results of operations and financial condition.

The nitrogen fertilizer operations depend in large part on the performance of third-party suppliers, including The BOC Group, for the supply of oxygen and nitrogen, and the City of Coffeyville for the supply of electricity. The contract with The BOC Group extends through 2020 and the electricity contract extends through 2019. Should either of those two suppliers fail to perform in accordance with the existing contractual arrangements, the gasification operation would be forced to a halt. Alternative sources of supply of oxygen, nitrogen or electricity could be difficult to obtain. Any shutdown of operations at the nitrogen fertilizer business could have a material negative effect upon our results of operations and financial condition.

Risks Related to Our Entire Business

Our refinery and nitrogen fertilizer facilities face operating hazards and interruptions, including unscheduled maintenance or downtime. We could face potentially significant costs to the extent these hazards or interruptions are not fully covered by our existing insurance coverage. Insurance companies that currently insure companies in the energy industry may cease to do so or may substantially increase premiums in the future.

Our operations, located primarily in a single location, are subject to significant operating hazards and interruptions. If any of our facilities, including our refinery and nitrogen fertilizer plant, experiences a major accident or fire, is damaged by severe weather, flooding or other natural disaster, or is otherwise forced to curtail its operations or shut down, we could incur significant losses which could have a material adverse impact on our financial results. In addition, a major accident, fire, flood, crude oil discharge or other event could damage our facilities or the environment and the surrounding community or result in injuries or loss of life. If our facilities experience a major accident or fire or other event or an interruption in supply or operations, our business could be materially adversely affected if the damage or liability exceeds the amounts of business interruption, property, terrorism and other insurance that we maintain against these risks and successfully collect. As required under our existing credit facilities, we maintain property and business interruption insurance capped at $1.25 billion which is subject to various deductibles and sub-limits for particular types of coverages (e.g., $300 million for a loss caused by flood). In the event of a business interruption, we would not be entitled to recover our losses until the interruption exceeds 45 days in the aggregate. We are fully exposed to losses in excess of this dollar cap and the various sub-limits, or business interruption losses that occur in the 45 days of our deductible period. These losses may be material. For example, a substantial portion of our lost revenue caused by the business interruption following the flood that occurred during the weekend of June 30, 2007 cannot be claimed because it was lost in the 45 days after the flood.

If our refinery is forced to curtail its operations or shut down due to hazards or interruptions like those described above, we will still be obligated to make any required payments to J. Aron under our Cash Flow Swap. We will be required to make payments under the Cash Flow Swap if crack spreads rise above a certain level. Such payments could have a material adverse impact on our financial results if, as a result of a disruption to our operations, we are unable to sustain sufficient revenues from which we can make such payments.

The energy industry is highly capital intensive, and the entire or partial loss of individual facilities can result in significant costs to both industry participants, such as us, and their insurance carriers. In recent years, several large energy industry claims have resulted in significant increases in the level of premium costs and deductible periods for participants in the energy industry. For example, during 2005, hurricanes Katrina and Rita caused significant damage to several petroleum refineries along the U.S. Gulf Coast, in addition to numerous oil and gas production facilities and pipelines in that region.

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As a result of large energy industry claims, insurance companies that have historically participated in underwriting energy related facilities could discontinue that practice, or demand significantly higher premiums or deductibles to cover these facilities. Although we currently maintain significant amounts of insurance, insurance policies are subject to annual renewal. If significant changes in the number or financial solvency of insurance underwriters for the energy industry occur, we may be unable to obtain and maintain adequate insurance at reasonable cost or we might need to significantly increase our retained exposures.

Our refinery consists of a number of processing units, many of which have been in operation for a number of years. One or more of the units may require unscheduled down time for unanticipated maintenance or repairs on a more frequent basis than our scheduled turnaround of every three to four years for each unit, or our planned turnarounds may last longer than anticipated. Our nitrogen fertilizer plant may also require scheduled or unscheduled downtime for maintenance or repairs. Scheduled and unscheduled maintenance could reduce our net income during the period of time that any of our units is not operating.

We may not recover all of the costs we have incurred or expect to incur in connection with the flood and crude oil discharge that occurred at our refinery in June/July 2007.

We have incurred and will continue to incur significant costs with respect to facility repairs, environmental remediation and property damage claims.

During the weekend of June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville. Our refinery and the nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded, sustained major damage and required extensive repairs. As of August 31, 2007, we had incurred approximately $67 million in costs to repair the refinery and currently estimate the total third party repair costs at approximately $86 million. The total third party cost to repair the nitrogen fertilizer facility is currently estimated at approximately $4 million. In addition to the cost of repairing the facilities, we experienced a significant revenue loss attributable to the property damage during the period when the facilities were not in operation.

Despite our efforts to complete a rapid shutdown of the refinery immediately before the flooding, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007. We are currently remediating the contamination caused by the crude oil discharge. We estimate that the total costs of oil remediation through completion will be approximately $7 million to $10 million, and that the total cost to resolve third party property damage claims will be approximately $25 million to $30 million. As a result, the total cost associated with remediation and property damage claims resolution is estimated to be approximately $32 million to $40 million. This estimate does not include potential fines or penalties which may be imposed by regulatory authorities or costs arising from potential natural resource damages claims (for which we are unable to estimate a range of possible costs at this time) or possible additional damages arising from class action lawsuits related to the flood.

The ultimate cost of environmental remediation and third party property damage is difficult to assess and could be higher than our current estimates.

It is difficult to estimate the ultimate cost of environmental remediation resulting from the crude oil discharge or the cost of third party property damage that we will ultimately be required to pay. The costs and damages that we ultimately pay may be greater than the amounts described and projected in this prospectus. Such excess costs and damages could be material.

We cannot predict the outcome of class action suits that have been brought against us with respect to the flood and crude oil discharge.

Two putative class action suits have been brought against us relating to these incidents. Due to the uncertainty of these suits, we are unable to estimate a range of possible loss at this time.

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Presently, we do not expect that the resolution of either or both of these suits will have a significant adverse effect on our business and results of operations. However, we cannot predict the outcome of these suits or their effect on our financial position or results of operations.

We do not know which of our losses our insurers will ultimately cover or when we will receive any insurance recovery.

During the time of the flood and crude oil discharge, Coffeyville Resources, LLC was covered by both property/business interruption and liability insurance policies. We are in the process of submitting claims to, responding to information requests from, and negotiating with various insurers with respect to costs and damages related to these incidents. However, we do not know which of our losses, if any, the insurers will ultimately cover or when we will receive any recovery. We may not be able to recover all of the costs we have incurred and losses we have suffered in connection with the flood and crude oil discharge. Further, we likely will not be able to recover most of the business interruption losses we incurred since a substantial portion of our facilities were operational within 45 days of the start of the flood.

Our operations involve environmental risks that may require us to make substantial capital expenditures to remain in compliance or to remediate current or future contamination that could give rise to material liabilities.

Our results of operations may be affected by increased costs resulting from compliance with the extensive federal, state and local environmental laws and regulations to which our facilities are subject and from contamination of our facilities and neighboring areas as a result of accidental spills, discharges or other historical releases of petroleum or hazardous substances.

Our operations are subject to a variety of federal, state and local environmental laws and regulations relating to the protection of the environment, including those governing the emission or discharge of pollutants into the environment, product specifications and the generation, treatment, storage, transportation, disposal and remediation of solid and hazardous waste and materials. Environmental laws and regulations that affect the operations, processes and margins for our refined products are extensive and have become progressively more stringent. Violations of these laws and regulations or permit conditions can result in substantial penalties, injunctive orders compelling installation of additional controls, civil and criminal sanctions, permit revocations and/or facility shutdowns.

In addition, new environmental laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement of laws and regulations or other developments could require us to make additional unforeseen expenditures. Many of these laws and regulations are becoming increasingly stringent, and the cost of compliance with these requirements can be expected to increase over time. The requirements to be met, as well as the technology and length of time available to meet those requirements, continue to develop and change. These expenditures or costs for environmental compliance could have a material adverse effect on our financial condition and results of operations.

All of our facilities operate under a number of federal and state permits, licenses and approvals with limits, terms and conditions containing a significant number of prescriptive and performance standards in order to operate. Our facilities are also required to meet compliance with prescriptive and performance standards specific to refining and chemical facilities as well as to general manufacturing facilities. All of these permits, licenses and standards require a significant amount of monitoring, record keeping and reporting requirements in order to demonstrate compliance with the underlying permit, license or standard. Inspections by federal and state governmental agencies may uncover incomplete or unknown documentation of compliance status that may result in the imposition of fines, penalties and injunctive relief that could have a material adverse effect on our ability to operate our facilities. Additionally, due to the nature of our manufacturing processes there may be times when we are unable to meet the standards and terms and conditions of these permits, licenses and standards

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that may not receive enforcement discretion from the governmental agencies, which may lead to the imposition of fines and penalties or operating restrictions that may have a material adverse effect on our ability to operate our facilities and accordingly our financial performance.

Our business is inherently subject to accidental spills, discharges or other releases of petroleum or hazardous substances into the environment and neighboring areas. Past or future spills related to any of our operations, including our refinery, pipelines, product terminals, fertilizer plant or transportation of products or hazardous substances from those facilities, may give rise to liability (including strict liability, or liability without fault, and potential cleanup responsibility) to governmental entities or private parties under federal, state or local environmental laws, as well as under common law. For example, we could be held strictly liable under the Comprehensive Environmental Responsibility, Compensation and Liability Act, or CERCLA, for past or future spills without regard to fault or whether our actions were in compliance with the law at the time of the spills. Pursuant to CERCLA and similar state statutes, we could be held liable for contamination associated with facilities we currently own or operate, facilities we formerly owned or operated and facilities to which we transported or arranged for the transportation of wastes or by-products containing hazardous substances for treatment, storage, or disposal. The potential penalties and clean-up costs for past or future releases or spills, liability to third parties for damage to their property or exposure to hazardous substances, or the need to address newly discovered information or conditions that may require response actions could be significant and could have a material adverse effect on our business, financial condition and results of operations.

Two of our facilities, including our Coffeyville oil refinery and the Phillipsburg terminal (which operated as a refinery until 1991), have environmental contamination. We have assumed Farmland s responsibilities under certain Resource Conservation and Recovery Act, or RCRA, corrective action orders related to contamination at or that originated from the Coffeyville refinery (which includes portions of the fertilizer plant) and the Phillipsburg terminal. If significant unforeseen liabilities that have been undetected to date by our extensive soil and groundwater investigation and sampling programs arise in the areas where we have assumed liability for the corrective action, that liability could have a material adverse effect on our results of operations and financial condition and may not be covered by insurance.

In addition, we may face liability for alleged personal injury or property damage due to exposure to chemicals or other hazardous substances located at or released from our facilities. We may also face liability for personal injury, property damage, natural resource damage or for cleanup costs for the alleged migration of contamination or other hazardous substances from our facilities to adjacent and other nearby properties.

We may face future liability for the off-site disposal of hazardous wastes. Pursuant to CERCLA, companies that dispose of, or arrange for the disposal of, hazardous substances at off-site locations can be held jointly and severally liable for the costs of investigation and remediation of contamination at those off-site locations, regardless of fault. We could become involved in litigation or other proceedings involving off-site waste disposal and the damages or costs in any such proceedings could be material.

For a discussion of environmental risks and impacts related to the flood and crude oil discharge, see We may not recover all of the costs we have incurred or expect to incur in connection with the flood and crude oil discharge that occurred at our refinery in June/July 2007 and Flood and Crude Oil Discharge.

We have a limited operating history as a stand-alone company.

Our limited historical financial performance as a stand-alone company makes it difficult for you to evaluate our business and results of operations to date and to assess our future prospects and viability. Our brief operating history has resulted in strong period-over-period revenue and profitability growth rates that may not continue in the future. We have been operating during a recent period of

significant growth in the profitability of the refined products industry which may not continue or could reverse. As a result, our results of operations may be lower than we currently expect and the price of our common stock may be volatile.

Because we are transferring our nitrogen fertilizer business to a newly formed limited partnership, we may be required in the future to share increasing portions of the fertilizer business cash flows with third parties and we may in the future be required to deconsolidate the fertilizer business from our consolidated financial statements, our historical financial statements do not reflect the new limited partnership structure and therefore our past financial performance may not be an accurate indicator of future performance.

Prior to the consummation of this offering, we will transfer our nitrogen fertilizer business to a newly formed limited partnership, whose managing general partner will be a new entity owned by our controlling stockholders and senior management. Although we will initially consolidate the Partnership in our financial statements, over time an increasing portion of the cash flow of the nitrogen fertilizer business will be distributed to our managing general partner if the Partnership increases its quarterly distributions above specified target distribution levels. In addition, if the Partnership consummates a public or private offering of limited partner interests to third parties, the new limited partners will also be entitled to receive cash distributions from the Partnership. This may require us to deconsolidate. Our historical financial statements do not reflect this new limited partnership structure and therefore our past financial performance may not be an accurate indicator of future performance. See Management s Discussion and Analysis of Financial Condition and Results of Operations Nitrogen Fertilizer Limited Partnership.

Our commodity derivative activities could result in losses and may result in period-to-period earnings volatility.

The nature of our operations results in exposure to fluctuations in commodity prices. If we do not effectively manage our derivative activities, we could incur significant losses. We monitor our exposure and, when appropriate, utilize derivative financial instruments and physical delivery contracts to mitigate the potential impact from changes in commodity prices. If commodity prices change from levels specified in our various derivative agreements, a fixed price contract or an option price structure could limit us from receiving the full benefit of commodity price changes. In addition, by entering into these derivative activities, we may suffer financial loss if we do not produce oil to fulfill our obligations. In the event we are required to pay a margin call on a derivative contract, we may be unable to benefit fully from an increase in the value of the commodities we sell. In addition, we may be required to make a margin payment before we are able to realize a gain on a sale resulting in a reduction in cash flow, particularly if prices decline by the time we are able to sell.

In June 2005, Coffeyville Acquisition LLC entered into the Cash Flow Swap, which is not subject to margin calls, in the form of three swap agreements for the period from July 1, 2005 to June 30, 2010 with J. Aron in connection with the Subsequent Acquisition. These agreements were subsequently assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. With crude oil capacity expected to reach 115,000 bpd by the end of 2007, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of the Credit Facility and upon meeting specific requirements related to an initial public offering, our leverage ratio and our credit ratings, and assuming our other credit facilities are terminated or amended to allow such actions, we may reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010. Otherwise, under the terms of our credit facilities, management has limited discretion to change the amount of hedged volumes under the Cash Flow Swap therefore affecting our exposure to market volatility. Because this derivative is based on NYMEX prices while our revenue is based on prices in the Coffeyville supply area, the contracts cannot completely eliminate all risk of price volatility. If the price of products on NYMEX is different from the

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value contracted in the swap, then we will receive from or owe to the counterparty the difference on each unit of product that is contracted in the swap. In addition, as a result of the accounting treatment of these contracts, unrealized gains and losses are charged to our earnings based on the increase or decrease in the market value of the unsettled position and the inclusion of such derivative gains or losses in earnings may produce significant period-to-period earnings volatility that is not necessarily reflective of our underlying operating performance. The positions under the Cash Flow Swap resulted in unrealized gains (losses) of $126.8 million and $(188.5) million for the year ended December 31, 2006 and the six months ended June 30, 2007, respectively. As of June 30, 2007, a $1.00 change in quoted prices for the crack spreads utilized in the Cash Flow Swap would result in a $54.8 million change to the fair value of derivative commodity position and the same change to net income. See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Derivative Instruments and Fair Value of Financial Instruments and Description of Our Indebtedness and the Cash Flow Swap Cash Flow Swap.

Both the petroleum and nitrogen fertilizer businesses depend on significant customers, and the loss of one or several significant customers may have a material adverse impact on our results of operations and financial condition.

The petroleum and nitrogen fertilizer businesses both have a high concentration of customers. Our four largest customers in the petroleum business represented 58.7%, 44.4% and 36.9% of our petroleum sales for the years ended December 31, 2005 and 2006 and the six months ended June 30, 2007, respectively. Further, in the aggregate the top five ammonia customers of the nitrogen fertilizer business represented 55.2%, 51.9% and 74.3% of its ammonia sales for the years ended December 31, 2005 and 2006 and the six months ended June 30, 2007, respectively, and the top five UAN customers of the nitrogen fertilizer business represented 43.1%, 30.0% and 38.8% of its UAN sales, respectively, for the same periods. Several significant petroleum, ammonia and UAN customers each account for more than 10% of sales of petroleum, ammonia and UAN, respectively. Given the nature of our business, and consistent with industry practice, we do not have long-term minimum purchase contracts with any of our customers. The loss of one or several of these significant customers, or a significant reduction in purchase volume by any of them, could have a material adverse effect on our results of operations and financial condition.

The petroleum and nitrogen fertilizer businesses may not be able to successfully implement their business strategies, which include completion of significant capital programs.

One of the business strategies of the petroleum and nitrogen fertilizer businesses is to implement a number of capital expenditure projects designed to increase productivity, efficiency and profitability. Many factors may prevent or hinder implementation of some or all of these projects, including compliance with or liability under environmental regulations, a downturn in refining margins, technical or mechanical problems, lack of availability of capital and other factors. Costs and delays have increased significantly during the past two years and the large number of capital projects underway in the industry has led to shortages in skilled craftsmen, engineering services and equipment manufacturing. Failure to successfully implement these profit-enhancing strategies may materially adversely affect our business prospects and competitive position. In addition, we expect to execute turnarounds at our refinery every three to four years, which involve numerous risks and uncertainties. These risks include delays and incurrence of additional and unforeseen costs. The next scheduled refinery turnaround will be in 2010. In addition, development and implementation of business strategies for the Partnership will be primarily the responsibility of the managing general partner of the Partnership.

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The acquisition strategy of our petroleum business and the nitrogen fertilizer business involves significant risks.

Both our petroleum business and the nitrogen fertilizer business will consider pursuing strategic and accretive acquisitions in order to continue to grow and increase profitability. However, acquisitions involve numerous risks and uncertainties, including intense competition for suitable acquisition targets; the potential unavailability of financial resources necessary to consummate acquisitions in the future; difficulties in identifying suitable acquisition targets or in completing any transactions identified on sufficiently favorable terms; and the need to obtain regulatory or other governmental approvals that may be necessary to complete acquisitions. In addition, any future acquisitions may entail significant transaction costs and risks associated with entry into new markets. In addition, even when acquisitions are completed, integration of acquired entities can involve significant difficulties, such as

unforeseen difficulties in the acquired operations and disruption of the ongoing operations of our petroleum business and the nitrogen fertilizer business;

failure to achieve cost savings or other financial or operating objectives with respect to an acquisition;

strain on the operational and managerial controls and procedures of our petroleum business and the nitrogen fertilizer business, and the need to modify systems or to add management resources;

difficulties in the integration and retention of customers or personnel and the integration and effective deployment of operations or technologies;

amortization of acquired assets, which would reduce future reported earnings;

possible adverse short-term effects on our cash flows or operating results;

diversion of management s attention from the ongoing operations of our petroleum business and the nitrogen fertilizer business; and

assumption of unknown material liabilities or regulatory non-compliance issues.

Failure to manage these acquisition growth risks could have a material adverse effect on the financial condition and/or operating results of our petroleum business and/or the nitrogen fertilizer business.

We are a holding company and depend upon our subsidiaries for our cash flow.

We are a holding company. Our subsidiaries conduct all of our operations and own substantially all of our assets. Consequently, our cash flow and our ability to meet our obligations or to pay dividends or make other distributions in the future will depend upon the cash flow of our subsidiaries and the payment of funds by our subsidiaries to us in the form of dividends, tax sharing payments or otherwise. In addition, Coffeyville Resources, LLC, our indirect subsidiary, and Coffeyville Refining & Marketing Holdings, Inc., our direct subsidiary, which are the primary obligors under our existing credit facilities, are holding companies and their ability to meet their debt service obligations depends on the cash flow of their subsidiaries. The ability of our subsidiaries to make any payments to us will depend on their earnings, the terms of their indebtedness, including the terms of our credit facilities, tax considerations and legal restrictions. In particular, our credit facilities currently impose significant limitations on the ability of our subsidiaries to make distributions to us and consequently our ability to pay dividends to our stockholders. Distributions that we receive from the Partnership will be primarily reinvested in our business rather than distributed to our stockholders. See also Risks Related to the Limited Partnership Structure Through Which We Will Hold Our Interest in the Nitrogen Fertilizer Business Our rights to receive distributions from the Partnership may be limited over time and Risks Related to the Limited Partnership Structure Through Which We Will Hold Our Interest in the Nitrogen Fertilizer Business The Partnership may not have sufficient available cash to enable it to

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make quarterly distributions to us following establishment of cash reserves and payment of fees and expenses.

Our significant indebtedness may affect our ability to operate our business, and may have a material adverse effect on our financial condition and results of operation.

As of September 30, 2007, we had total debt outstanding of $841.1 million, $150 million in funded letters of credit outstanding and borrowing availability of $168.1 million under our credit facilities. We and our subsidiaries may be able to incur significant additional indebtedness in the future. If new indebtedness is added to our current indebtedness, the risks described below could increase. Our high level of indebtedness could have important consequences, such as:

- limiting our ability to obtain additional financing to fund our working capital, acquisitions, expenditures, debt service requirements or for other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service debt;
- limiting our ability to compete with other companies who are not as highly leveraged;
- placing restrictive financial and operating covenants in the agreements governing our and our subsidiaries long-term indebtedness and bank loans, including, in the case of certain indebtedness of subsidiaries, certain covenants that restrict the ability of subsidiaries to pay dividends or make other distributions to us;
- exposing us to potential events of default (if not cured or waived) under financial and operating covenants contained in our or our subsidiaries debt instruments that could have a material adverse effect on our business, financial condition and operating results;
- increasing our vulnerability to a downturn in general economic conditions or in pricing of our products; and
- limiting our ability to react to changing market conditions in our industry and in our customers industries.

In addition, borrowings under our credit facilities bear interest at variable rates. If market interest rates increase, such variable-rate debt will create higher debt service requirements, which could adversely affect our cash flow. Our interest expense for the year ended December 31, 2006 was $34.1 million on a pro forma basis. Each 1/8% increase or decrease in the applicable interest rates under our credit facilities would correspondingly change our interest expense by approximately $625,000 per year.

In addition to our debt service obligations, our operations require substantial investments on a continuing basis. Our ability to make scheduled debt payments, to refinance our obligations with respect to our indebtedness and to fund capital and non-capital expenditures necessary to maintain the condition of our operating assets, properties and systems software, as well as to provide capacity for the growth of our business, depends on our financial and operating performance, which, in turn, is subject to prevailing economic conditions and financial, business, competitive, legal and other factors. In addition, we are and will be subject to covenants contained in agreements governing our present and future indebtedness. These covenants include and will likely include restrictions on certain payments, the granting of liens, the incurrence of additional indebtedness, dividend restrictions affecting subsidiaries, asset sales, transactions with affiliates and mergers and consolidations. Any failure to comply with these covenants could result in a default under our credit facilities. Upon a default, unless waived, the lenders under our secured credit facilities would have all remedies available to a secured lender, and could elect to terminate their commitments, cease making further loans, institute foreclosure proceedings against our or our subsidiaries assets, and force us and our subsidiaries into bankruptcy or liquidation. In addition, any defaults under the credit facilities or any other debt could trigger cross defaults under other or future credit agreements. Our operating results may not be sufficient to service our indebtedness or to fund our other expenditures and we may not be able to obtain financing to meet these requirements.

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If the Partnership seeks to consummate a public or private offering, we may be required to use our commercially reasonable efforts to amend our credit facilities to remove the Partnership as a guarantor. Any such amendment could result in increased fees to us or other onerous terms in our credit facilities. In addition, we may not be able to obtain such an amendment on terms acceptable to us or at all.

If the managing general partner elects to pursue a public or private offering of limited partner interests in the Partnership, we expect that any such transaction would require amendments to our credit facilities, as well as the Cash Flow Swap, in order to remove the Partnership and its subsidiaries as obligors under such instruments. Any such amendments could result in significant changes to our credit facilities pricing, mandatory repayment provisions, covenants and other terms and could result in increased interest costs and require payment by us of additional fees. We have agreed to use our commercially reasonable efforts to obtain such amendments if the managing general partner elects to cause the Partnership to pursue a public or private offering and gives us at least 90 days written notice. However, we may not be able to obtain any such amendment on terms acceptable to us or at all. If we are not able to amend our credit facilities on terms satisfactory to us, we may need to refinance them with other facilities. We will not be considered to have used our commercially reasonable efforts to obtain such amendments if we do not effect the requested modifications due to (i) payment of fees to the lenders or the swap counterparty, (ii) the costs of this type of amendment, (iii) an increase in applicable margins or spreads or (iv) changes to the terms required by the lenders including covenants, events of default and repayment and prepayment provisions; provided that (i), (ii), (iii) and (iv) in the aggregate are not likely to have a material adverse effect on us.

If we lose any of our key personnel, we may be unable to effectively manage our business or continue our growth.

Our future performance depends to a significant degree upon the continued contributions of our senior management team and key technical personnel. The loss or unavailability to us of any member of our senior management team or a key technical employee could negatively affect our ability to operate our business and pursue our strategy. We face competition for these professionals from our competitors, our customers and other companies operating in our industry. To the extent that the services of members of our senior management team and key technical personnel would be unavailable to us for any reason, we would be required to hire other personnel to manage and operate our company and to develop our products and strategy. We may not be able to locate or employ such qualified personnel on acceptable terms or at all.

A substantial portion of our workforce is unionized and we are subject to the risk of labor disputes and adverse employee relations, which may disrupt our business and increase our costs.

As of June 30, 2007, approximately 39% of our employees, all of whom work in our petroleum business, were represented by labor unions under collective bargaining agreements expiring in 2009. We may not be able to renegotiate our collective bargaining agreements when they expire on satisfactory terms or at all. A failure to do so may increase our costs. In addition, our existing labor agreements may not prevent a strike or work stoppage at any of our facilities in the future, and any work stoppage could negatively affect our results of operations and financial condition.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company, we will be subject to the reporting requirements of the Securities Exchange Act of 1934, or the Exchange Act, and the corporate governance standards of the Sarbanes-Oxley Act of 2002, or Sarbanes-Oxley Act. These requirements may place a strain on our management, systems and resources. The Exchange Act will require that we file annual, quarterly and current reports with respect to our business and financial condition. The Sarbanes-Oxley Act will require that we maintain effective disclosure controls and procedures and internal controls over financial reporting. Due to our limited operating history as a stand-alone company, our disclosure controls and procedures and internal controls may not meet all of the standards applicable to public companies. In order to maintain and improve the effectiveness of our disclosure controls and procedures and internal control over financial reporting, significant resources and management oversight will be required. This may divert management s attention from other business concerns, which could have a material adverse effect on our business, financial condition, results of operations and the price of our common stock.

We will be exposed to risks relating to evaluations of controls required by Section 404 of the Sarbanes-Oxley Act.

We are in the process of evaluating our internal controls systems to allow management to report on, and our independent auditors to audit, our internal controls over financial reporting. We will be performing the system and process evaluation and testing (and any necessary remediation) required to comply with the management certification and auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, and will be required to comply with Section 404 in our annual report for the year ended December 31, 2008 (subject to any change in applicable SEC rules). Furthermore, upon completion of this process, we may identify control deficiencies of varying degrees of severity under applicable U.S. Securities and Exchange Commission, or SEC, and Public Company Accounting Oversight Board, or PCAOB, rules and regulations that remain unremediated. As a public company, we will be required to report, among other things, control deficiencies that constitute a material weakness or changes in internal controls that, or that are reasonably likely to, materially affect internal controls over financial reporting. A material weakness is a significant deficiency or combination of significant deficiencies that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

If we fail to implement the requirements of Section 404 in a timely manner, we might be subject to sanctions or investigation by regulatory authorities such as the SEC or the PCAOB. If we do not implement improvements to our disclosure controls and procedures or to our internal controls in a timely manner, our independent registered public accounting firm may not be able to certify as to the effectiveness of our internal controls over financial reporting pursuant to an audit of our internal controls over financial reporting. This may subject us to adverse regulatory consequences or a loss of confidence in the reliability of our financial statements. We could also suffer a loss of confidence in the reliability of our financial statements if our independent registered public accounting firm reports a material weakness in our internal controls, if we do not develop and maintain effective controls and procedures or if we are otherwise unable to deliver timely and reliable financial information. Any loss of confidence in the reliability of our financial statements or other negative reaction to our failure to develop timely or adequate disclosure controls and procedures or internal controls could result in a decline in the price of our common stock. In addition, if we fail to remedy any material weakness, our financial statements may be inaccurate, we may face restricted access to the capital markets and our stock price may be adversely affected.

We are a controlled company within the meaning of the New York Stock Exchange rules and, as a result, will qualify for, and may rely on, exemptions from certain corporate governance requirements.

A company of which more than 50% of the voting power is held by an individual, a group or another company is a controlled company within the meaning of the New York Stock Exchange rules and may elect not to comply with certain corporate governance requirements of the New York Stock Exchange, including:

- the requirement that a majority of our board of directors consist of independent directors;
- the requirement that we have a nominating/corporate governance committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities; and

the requirement that we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities.

Following this offering, we will rely on some or all of these exemptions as a controlled company. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the New York Stock Exchange.

New regulations concerning the transportation of hazardous chemicals, risks of terrorism, the security of chemical manufacturing facilities and increased insurance costs could result in higher operating costs.

The costs of complying with regulations relating to the transportation of hazardous chemicals and security associated with the refining and nitrogen fertilizer facilities may have a negative impact on our operating results and may cause the price of our common stock to decline. Targets such as refining and chemical manufacturing facilities may be at greater risk of future terrorist attacks than other targets in the United States. As a result, the petroleum and chemical industries have responded to the issues that arose due to the terrorist attacks on September 11, 2001 by starting new initiatives relating to the security of petroleum and chemical industry facilities and the transportation of hazardous chemicals in the United States. Simultaneously, local, state and federal governments have begun a regulatory process that could lead to new regulations impacting the security of refinery and chemical plant locations and the transportation of petroleum and hazardous chemicals. Our business or our customers businesses could be materially adversely affected because of the cost of complying with new regulations.

If we are not able to successfully defend against third-party claims of intellectual property infringement, our business may be adversely affected.

There are currently no claims pending against us relating to the infringement of any third-party intellectual property rights; however, in the future we may face claims of infringement that could interfere with our ability to use technology that is material to our business operations. Any litigation of this type, whether successful or unsuccessful, could result in substantial costs to us and diversions of our resources, either of which could negatively affect our business, profitability or growth prospects. In the event a claim of infringement against us is successful, we may be required to pay royalties or license fees for past or continued use of the infringing technology, or we may be prohibited from using the infringing technology altogether. If we are prohibited from using any technology as a result of such a claim, we may not be able to obtain licenses to alternative technology adequate to substitute for the technology we can no longer use, or licenses for such alternative technology may only be available on terms that are not commercially reasonable or acceptable to us. In addition, any substitution of new technology for currently licensed technology may require us to make substantial changes to our manufacturing processes or equipment or to our products, and may have a material adverse effect on our business, profitability or growth prospects.

If licensed technology is no longer available, the refinery and nitrogen fertilizer businesses may be adversely affected.

The refinery and nitrogen fertilizer businesses have licensed, and may license in the future, a combination of patent, trade secret and other intellectual property rights of third parties for use in their business. If any of these license agreements were to be terminated, licenses to alternative technology may not be available, or may only be available on terms that are not commercially reasonable or acceptable. In addition, any substitution of new technology for currently-licensed technology may require substantial changes to manufacturing processes or equipment and may have a material adverse effect on our business, profitability or growth prospects.

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Risks Related to this Offering

There is no existing market for our common stock, and we do not know if one will develop to provide you with adequate liquidity. If our stock price fluctuates after this offering, you could lose a significant part of your investment.

Prior to this offering, there has not been a public market for our common stock. If an active trading market does not develop, you may have difficulty selling any of our common stock that you buy. The initial public offering price for the shares will be determined by negotiations between us and the underwriters and may not be indicative of prices that will prevail in the open market following this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in this offering. The market price of our common stock may be influenced by many factors including:

- the failure of securities analysts to cover our common stock after this offering or changes in financial estimates by analysts;
- announcements by us or our competitors of significant contracts or acquisitions;
- variations in quarterly results of operations;
- loss of a large customer or supplier;
- general economic conditions;
- terrorist acts;
- future sales of our common stock; and
- investor perceptions of us and the industries in which our products are used.

As a result of these factors, investors in our common stock may not be able to resell their shares at or above the initial offering price. In addition, the stock market in general has experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of companies like us. These broad market and industry factors may materially reduce the market price of our common stock, regardless of our operating performance.

Following the completion of this offering, the Goldman Sachs Funds and the Kelso Funds will continue to control us and may have conflicts of interest with other stockholders. Conflicts of interest may arise because our principal stockholders or their affiliates have continuing agreements and business relationships with us.

Upon completion of this offering, the Goldman Sachs Funds will control 37.4% of our outstanding common stock, or 36.1% if the underwriters exercise their option in full, and the Kelso Funds will control 36.8% of our outstanding common stock, or 35.6% if the underwriters exercise their option in full. As a result, the Goldman Sachs Funds and the Kelso Funds will continue to be able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other stockholders, the outcome of any corporate transaction or other matter submitted to our stockholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. The Goldman Sachs Funds and the Kelso Funds will also have sufficient voting power to amend our organizational documents.

Conflicts of interest may arise between our principal stockholders and us. Affiliates of some of our principal stockholders engage in transactions with our company. We obtain the majority of our crude oil supply through a crude oil credit intermediation agreement with J. Aron, a subsidiary of The Goldman Sachs Group, Inc. and an affiliate of the Goldman Sachs Funds, and Coffeyville Resources, LLC currently has outstanding commodity derivative contracts (swap agreements) with J. Aron for the period from July 1, 2005 to June 30, 2010. In addition, Goldman Sachs Credit Partners, L.P. is the sole or joint lead arranger for our four credit facilities. See Certain Relationships and Related Party Transactions. Further, the Goldman Sachs Funds and the Kelso Funds are in the business of making investments in companies and may, from time to time, acquire and hold interests in businesses that compete directly or indirectly with us and they may either directly, or through affiliates, also maintain business relationships with companies that may directly compete with us. In general, the Goldman Sachs Funds and the Kelso Funds or their affiliates could pursue business interests or exercise their voting power as stockholders in ways that are detrimental to us, but beneficial to themselves or to other companies in which they invest or with whom they have a material relationship. Conflicts of interest could also arise with respect to business opportunities that could be advantageous to the Goldman Sachs Funds and the Kelso Funds and they may pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us. Under the terms of our certificate of incorporation, the Goldman Sachs Funds and the Kelso Funds will have no obligation to offer us corporate opportunities. See Description of Capital Stock Corporate Opportunities.

Other conflicts of interest may arise between our principal stockholders and us because the Goldman Sachs Funds and the Kelso Funds will control the managing general partner of the Partnership which will hold the nitrogen fertilizer business. The managing general partner will manage the operations of the Partnership (subject to our rights to participate in the appointment, termination and compensation of the chief executive officer and chief financial officer of the managing general partner and our other specified joint management rights) and will also hold incentive distribution rights which, over time, entitle the managing general partner to receive increasing percentages of the Partnership s quarterly distributions if the Partnership increases the amount of distributions. Although the managing general partner will have a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and us (as a holder of special units in the Partnership), the fiduciary duty is limited by the terms of the partnership agreement and the directors and officers of the managing general partner also will have a fiduciary duty to manage the managing general partner in a manner beneficial to the owners of the managing general partner. The interests of the owners of the managing general partner may differ significantly from, or conflict with, our interests and the interests of our stockholders. As a result of these conflicts, the managing general partner of the Partnership may favor its own interests and/or the interests of its owners over our interests and the interests of our stockholders (and the interests of the Partnership). In particular, because the managing general partner owns the incentive distribution rights, it may be incentivized to maximize future cash flows by taking current actions which may be in its best interests over the long term. See Risks Related to the Limited Partnership Structure Through Which We Will Hold Our Interest in the Nitrogen Fertilizer Business Our rights to receive distributions from the Partnership may be limited over time and Risks Related to the Limited Partnership Structure Through Which We Will Hold Our Interest in the Nitrogen Fertilizer Business The managing general partner of the Partnership will have a fiduciary duty to favor the interests of its owners, and these interests may differ from, or conflict with, our interests and the interests of our stockholders. In addition, if the value of the managing general partner interest were to increase over time, this increase in value and any realization of such value upon a sale of the managing general partner interest would benefit the owners of the managing general partner, which are the Goldman Sachs Funds and the Kelso Funds, as well as our senior management, rather than our company and our stockholders. Such increase in value could be significant if the Partnership performs well. See The Nitrogen Fertilizer Limited Partnership.

Further, decisions made by the Goldman Sachs Funds and the Kelso Funds with respect to their shares of common stock could trigger cash payments to be made by us to certain members of our senior management under our phantom unit appreciation plans. Phantom points granted under the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I), or the Phantom Unit Plan I, and phantom points that we intend to grant under the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II), or the Phantom Unit Plan II, represent a contractual right to receive a cash payment when payment is made in respect of certain profits interests in Coffeyville Acquisition LLC and, after the consummation of the Transactions, Coffeyville Acquisition II LLC. Definitions of the terms phantom points, Phantom Unit Plan I, and Phantom Unit Plan II are contained in the section of this prospectus entitled Glossary of Selected Terms. If either the Goldman Sachs Funds or the Kelso Funds sell any or all of the shares of common stock of CVR Energy which they beneficially own through Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, they may then cause Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, to make distributions

to their members in respect of their profits interests. Because payments under the phantom unit plans are triggered by payments in respect of profit interests under the Coffeyville Acquisition LLC Agreement and Coffeyville Acquisition II LLC Agreement, we would therefore be obligated to make cash payments under the phantom unit appreciation plans. This could negatively affect our cash reserves, which could negatively affect our results of operations and financial condition. We estimate that any such cash payments should not exceed $50 million, assuming all of the shares of our common stock held by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC were sold at the initial public offering price of $19.00 per share. Following the completion of this offering, Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC may make a significant revision to the Phantom Unit Plan I and Phantom Unit Plan II, respectively, to provide that a significant portion of the payments in respect of phantom service points and phantom performance points will be paid on fixed payment dates (for example, in annual installments) rather than within 30 days from the date distributions are made pursuant to the respective limited liability company agreements. This amendment, if enacted, would mitigate in part the effect of decisions made by the Goldman Sachs Funds and the Kelso Funds with respect to their shares of common stock on cash payments by the plans because those payments scheduled to be made on fixed dates would not be triggered by distributions from Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, to its members. Coffeyville Acquisition LLC has indicated that it is continuing to explore other ways to revise the Phantom Unit Plans.

In addition, one of the Goldman Sachs Funds and one of the Kelso Funds have each guaranteed 50% of (1) our obligations under the $25 million secured facility, the $25 million unsecured facility and the $75 million unsecured facility and (2) our payment obligations under the Cash Flow Swap in the amount of $123.7 million, plus accrued interest. In addition, Coffeyville Acquisition LLC currently guarantees and, following the closing of this offering, Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC will each guarantee 50% of our obligations under the $75 million unsecured facility. As a result of these guarantees, the Goldman Sachs Funds and the Kelso Funds may have interests that conflict with those of our other shareholders.

Since June 24, 2005, we have made one cash distribution to the Goldman Sachs Funds and the Kelso Funds. This distribution, in the aggregate amount of $244.7 million, was made in December 2006. In addition, the Goldman Sachs Funds and the Kelso Funds have received and continue to receive advisory and other fees pursuant to separate consulting and advisory agreements between Coffeyville Acquisition LLC and each of Goldman, Sachs & Co. and Kelso & Company, L.P. In addition, prior to the consummation of this offering, we intend to make a special dividend to the Goldman Sachs Funds and the Kelso Funds in an aggregate amount of approximately $10.3 million, which they will contribute to Coffeyville Acquisition III LLC in connection with the purchase of the managing general partner of the Partnership from us. The Goldman Sachs Funds and the Kelso Funds are not contractually obligated to contribute the special dividend of $10.3 million to Coffeyville Acquisition III LLC for its purchase of the managing general partner. However, they have indicated to us that they intend to do so upon the closing of this offering and we have amended our Credit Facility in order to allow such purchase and distribution.

As a result of these relationships, including their ownership of the managing general partner of the Partnership, the interests of the Goldman Sachs Funds and the Kelso Funds may not coincide with the interests of our company or other holders of our common stock. So long as the Goldman Sachs Funds and the Kelso Funds continue to control a significant amount of the outstanding shares of our common stock, the Goldman Sachs Funds and the Kelso Funds will continue to be able to strongly influence or effectively control our decisions, including potential mergers or acquisitions, asset sales and other significant corporate transactions. In addition, so long as the Goldman Sachs Funds and the Kelso Funds continue to control the managing general partner of the Partnership, they will be able to effectively control actions taken by the Partnership (subject to our specified joint management rights), which may not be in our interests or the interest of our stockholders. See Certain Relationships and Related Party Transactions.

You will incur immediate and substantial dilution.

The initial public offering price of our common stock is substantially higher than the adjusted net tangible book value per share of our outstanding common stock. As a result, if you purchase shares in this offering, you will incur immediate and substantial dilution in the amount of $15.75 per share. See Dilution.

Shares eligible for future sale may cause the price of our common stock to decline.

Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. This could also impair our ability to raise additional capital through the sale of our equity securities. Under our amended and restated certificate of incorporation, we are authorized to issue up to 350,000,000 shares of common stock, of which 83,141,291 shares of common stock will be outstanding following this offering. Of these shares, the 20,000,000 shares of common stock sold in this offering will be freely transferable without restriction or further registration under the Securities Act by persons other than affiliates, as that term is defined in Rule 144 under the Securities Act. Our principal stockholders, directors and executive officers will enter into lock-up agreements, pursuant to which they are expected to agree, subject to certain exceptions, not to sell or transfer, directly or indirectly, any shares of our common stock for a period of 180 days from the date of this prospectus, subject to extension in certain circumstances. See Shares Eligible for Future Sale.

Risks Related to the Limited Partnership Structure Through Which We Will Hold Our Interest in the Nitrogen Fertilizer Business

Because we will neither serve as, nor control, the managing general partner of the Partnership, the managing general partner may operate the Partnership in a manner with which we disagree or which is not in our interest.

CVR GP, LLC, or Fertilizer GP, a new entity owned by our controlling stockholders and senior management, will be the managing general partner of the Partnership which will hold the nitrogen fertilizer business. The managing general partner will be authorized to manage the operations of the nitrogen fertilizer business (subject to our specified joint management rights), and we will not control the managing general partner. Although our senior management will also serve as the senior management of Fertilizer GP, in accordance with a services agreement between us, Fertilizer GP and the Partnership, our senior management will operate the Partnership under the direction of the managing general partner s board of directors and Fertilizer GP has the right to select different management at any time (subject to our joint right in relation to the chief executive officer and chief financial officer of the managing general partner). Accordingly, the managing general partner may operate the Partnership in a manner with which we disagree or which is not in the interests of our company and our stockholders.

Our interest in the Partnership will consist of special units. The substantial majority of these units will be general partner interests that will give us defined rights to participate in the management and governance of the Partnership. These rights will include the right to approve the appointment, termination of employment and compensation of the chief executive officer and chief financial officer of Fertilizer GP, not to be exercised unreasonably, and to approve specified major business transactions such as significant mergers and asset sales. We will also have the right to appoint two directors to Fertilizer GP s board of directors. However, our special GP units will be converted into limited partner interests, and we will lose the rights listed above, if we fail to hold at least 15% of the units in the Partnership. See The Nitrogen Fertilizer Limited Partnership.

Our rights to receive distributions from the Partnership may be limited over time.

As a holder of 30,333,333 special units (which may convert into common and/or subordinated units, and which we may sell from time to time), we will be entitled to receive a quarterly distribution of $0.4313 per unit (or $13.1 million per quarter in the aggregate, assuming we do not sell any of our units) from the Partnership to the extent the Partnership has sufficient available cash after establishment of cash reserves and payment of fees and expenses before any distributions are made in respect of the incentive distribution rights. The Partnership will be required to distribute all of its cash on hand at the end of each quarter, less reserves established by the managing general partner in its discretion. In addition, the managing general partner, Fertilizer GP, will have no right to receive distributions in respect of its incentive distribution rights (i) until the Partnership has distributed all aggregate adjusted operating surplus generated by the Partnership during the period from its formation through December 31, 2009 and (ii) for so long as the Partnership or its subsidiaries are guarantors under our credit facilities.

However, distributions of amounts greater than the aggregate adjusted operating surplus (as defined under The Nitrogen Fertilizer Limited Partnership Cash Distributions by the Partnership Operating Surplus, Capital Surplus and Adjusted Operating Surplus) generated through December 31, 2009 will be allocated between us and Fertilizer GP (and the holders of any other interests in the Partnership), and in the future the allocation will grant Fertilizer GP a greater percentage of the Partnership s cash distributions as more cash becomes available for distribution. In particular, if quarterly distributions exceed the target of $0.4313 per unit, Fertilizer GP will be entitled to increasing percentages of the distributions, up to 48% of the distributions above the highest target level, in respect of its incentive distribution rights. Therefore, we will receive a smaller percentage of quarterly cash distributions from the Partnership if the Partnership increases its quarterly distributions above the set amount per unit. This could incentivise Fertilizer GP, as managing general partner, to cause the Partnership to make capital expenditures for maintenance, which reduces operating surplus (as defined under The Nitrogen Fertilizer Limited Partnership Cash Distributions by the Partnership Operating Surplus, Capital Surplus and Adjusted Operating Surplus), rather than for improvement or expansion, which does not, and accordingly effect the amount of cash available for distribution. Fertilizer GP could also be incentivized to cause the Partnership to make capital expenditures for maintenance prior to December 31, 2009 that it would otherwise make at a later date in order to reduce operating surplus generated prior to such date. In addition, Fertilizer GP s discretion in determining the level of cash reserves may materially adversely affect the Partnership s ability to make cash distributions to us.

Moreover, if the Partnership issues common units in a public or private offering, at least 40% (and potentially all) of our special units will become subordinated units. We will not be entitled to any distributions on our subordinated units until the common units issued in the public or private offering and our common units (which the balance of our special units will become) have received the minimum quarterly distribution, or MQD, of $0.375 per unit (which may be reduced without our consent in connection with the public or private offering, or could be increased with our consent), plus any accrued and unpaid arrearages in the minimum quarterly distribution from prior quarters. The managing general partner, and not CVR Energy, has authority to decide whether or not to pursue such an offering. As a result, our right to distributions will diminish if the managing general partner decides to pursue such an offering. See The Nitrogen Fertilizer Limited Partnership Cash Distributions by the Partnership Distributions from Operating Surplus.

The managing general partner of the Partnership will have a fiduciary duty to favor the interests of its owners, and these interests may differ from, or conflict with, our interests and the interests of our stockholders.

The managing general partner of the Partnership, Fertilizer GP, will be responsible for the management (subject to our specified management rights) of the Partnership. Although Fertilizer GP will have a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and holders of interests in the Partnership (including us, in our capacity as holder of special units), the fiduciary duty is specifically limited by the express terms of the partnership agreement and the directors and officers of Fertilizer GP also will have a fiduciary duty to manage Fertilizer GP in a manner beneficial to the owners of Fertilizer GP. The interests of the owners of Fertilizer GP may differ from, or conflict with, our interests and the interests of our stockholders. In resolving these conflicts, Fertilizer GP may favor its own interests and/or the interests of its owners over our interests

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and the interests of our stockholders (and the interests of the Partnership). In addition, while our directors and officers will have a fiduciary duty to make decisions in our interests and the interests of our stockholders, one of our wholly-owned subsidiaries is also a general partner of the Partnership and, therefore, in such capacity, will have a fiduciary duty to exercise rights as general partner in a manner beneficial to the Partnership and its unit holders, subject to the limitations contained in the partnership agreement. As a result of these conflicts, our directors and officers may feel obligated to take actions that benefit the Partnership as opposed to us and our stockholders.

The potential conflicts of interest include, among others, the following:

Fertilizer GP, as managing general partner of the Partnership, will hold all of the incentive distribution rights in the Partnership. Incentive distribution rights will give Fertilizer GP a right to increasing percentages of the Partnership s quarterly distributions after the Partnership has distributed all aggregate adjusted operating surplus generated by the Partnership during the period from its formation through December 31, 2009, assuming the Partnership and its subsidiaries are released from their guaranty of our credit facilities. Fertilizer GP may have an incentive to manage the Partnership in a manner which increases these future cash flows rather than in a manner which increases current cash flows.

The initial directors and executive officers of Fertilizer GP will also serve as directors and executive officers of CVR Energy. The executive officers who work for both us and Fertilizer GP, including our chief executive officer, chief operating officer, chief financial officer and general counsel, will divide their time between our business and the business of the Partnership. These executive officers will face conflicts of interests from time to time in making decisions which may benefit either our company or the Partnership. However, when making decisions on behalf of the Partnership, they will be acting in their capacity as directors and officers of the managing general partner and not us.

The owners of Fertilizer GP, who are also our controlling stockholders and senior management, will be permitted to compete with us or the Partnership or to own businesses that compete with us or the Partnership. In addition, the owners of Fertilizer GP will not be required to share business opportunities with us, and our owners will not be required to share business opportunities with the Partnership or Fertilizer GP.

Neither the partnership agreement nor any other agreement will require the owners of Fertilizer GP to pursue a business strategy that favors us or the Partnership. The owners of Fertilizer GP will have fiduciary duties to make decisions in their own best interests, which may be contrary to our interests and the interests of the Partnership. In addition, Fertilizer GP will be allowed to take into account the interests of parties other than us, such as its owners, in resolving conflicts of interest, which will have the effect of limiting its fiduciary duty to us.

The partnership agreement will limit the liability and reduce the fiduciary duties of Fertilizer GP, while also restricting the remedies available to the unit holders of the Partnership, including us, for actions that, without these limitations, might constitute breaches of fiduciary duty. Delaware partnership law permits such contractual reductions of fiduciary duty. As a result of our ownership interest in the Partnership, we may consent to some actions that might otherwise constitute a breach of fiduciary or other duties applicable under state law.

Fertilizer GP will determine the amount and timing of asset purchases and sales, capital expenditures, borrowings, repayment of indebtedness, issuances of additional partnership units and cash reserves maintained by the Partnership (subject to our specified joint management rights as holder of special GP rights), each of which can affect the amount of cash that is available for distribution to us in our capacity as a holder of special units and the amount of cash paid to Fertilizer GP in respect of its IDRs.

In some instances Fertilizer GP may cause the Partnership to borrow funds in order to permit the payment of cash distributions, where the purpose or effect of the borrowing is to make incentive distributions which benefit Fertilizer GP. Fertilizer GP will also be able to determine the amount and timing of any capital expenditures and whether a capital expenditure is for maintenance, which reduces operating surplus, or improvement, which does not. Such determinations can affect the amount of cash that is available for distribution and the manner in which the cash is distributed.

Fertilizer GP may exercise its rights to call and purchase all of the Partnership s equity securities of any class if at any time it and its affiliates (excluding us) own more than 80% of the outstanding securities of such class.

Fertilizer GP will control the enforcement of obligations owed to the Partnership by it and its affiliates. In addition, Fertilizer GP will decide whether to retain separate counsel or others to perform services for the Partnership.

The partnership agreement limits the fiduciary duties of the managing general partner and restricts the remedies available to us for actions taken by the managing general partner that might otherwise constitute breaches of fiduciary duty.

The partnership agreement contains provisions that reduce the standards to which Fertilizer GP, as the managing general partner, would otherwise be held by state fiduciary duty law. For example:

The partnership agreement permits Fertilizer GP to make a number of decisions in its individual capacity, as opposed to its capacity as a general partner. This entitles Fertilizer GP to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us or our affiliates.

The partnership agreement provides that Fertilizer GP will not have any liability to the Partnership or to us for decisions made in its capacity as managing general partner so long as it acted in good faith, meaning it believed that the decisions were in the best interests of the Partnership.

The partnership agreement provides that Fertilizer GP and its officers and directors will not be liable for monetary damages to the Partnership for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that Fertilizer GP or those persons acted in bad faith or engaged in fraud or willful misconduct.

The partnership agreement generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of Fertilizer GP and not involving a vote of unit holders must be on terms no less favorable to the Partnership than those generally provided to or available from unrelated third parties or be fair and reasonable to the Partnership and that, in determining whether a transaction or resolution is fair and reasonable, Fertilizer GP may consider the totality of the relationship between the parties involved, including other transactions that may be particularly advantageous or beneficial to the Partnership.

The Partnership will have a preferential right to pursue corporate opportunities before we can pursue them.

We will enter into an agreement with the Partnership in order to clarify and structure the division of corporate opportunities between us and the Partnership. Under this agreement, we have agreed not to engage in the production, transportation or distribution, on a wholesale basis, of fertilizers in the contiguous United States, subject to limited exceptions (fertilizer restricted business). In addition, the Partnership has agreed not to engage in the ownership or operation within the United States of any refinery with processing capacity greater than 20,000 barrels per day whose primary business is producing transportation fuels or the ownership or operation outside the United States of any refinery (refinery restricted business).

With respect to any business opportunity other than those covered by a fertilizer restricted business or a refinery restricted business, we have agreed that the Partnership will have a preferential right to pursue such opportunities before we may pursue them. If the managing general partner of the Partnership elects not to pursue the business opportunity, then we will be free to pursue such opportunity. This provision will continue so long as we continue to own 50% of the outstanding units of

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the Partnership. See The Nitrogen Fertilizer Limited Partnership Other Intercompany Agreements Omnibus Agreement.

If the Partnership completes a public offering or private placement of limited partner interests, our voting power in the Partnership would be reduced and our rights to distributions from the Partnership could be materially adversely affected.

Fertilizer GP may, in its sole discretion, elect to pursue one or more public or private offerings of limited partner interests in the Partnership. Fertilizer GP will have the sole authority to determine the timing, size (subject to our joint management rights for any initial offering in excess of $200 million, exclusive of the underwriters option to purchase additional limited partner interests, if any), and underwriters or initial purchasers, if any, for such offerings, if any. Any public or private offering of limited partner interests could materially adversely affect us in several ways. For example, if such an offering occurs, our percentage interest in the Partnership would be diluted. Some of our voting rights in the Partnership could thus become less valuable, since we would not be able to take specified actions without support of other unit holders. For example, since the vote of 80% of unit holders is required to remove the managing general partner in specified circumstances, if the managing general partner sells more than 20% of the units to a third party we would not have the right, unilaterally, to remove the general partner under the specified circumstances.

In addition, if the Partnership completes an offering of limited partner interests, the distributions that we receive from the Partnership would decrease because the Partnership s distributions will have to be shared with the new limited partners, and the new limited partners right to distributions will be superior to ours because at least 40% (and potentially all) of our units will become subordinated units. Pursuant to the terms of the partnership agreement, the new limited partners and Fertilizer GP will have superior priority to distributions in some circumstances. Subordinated units will not be entitled to receive distributions unless and until all common units have received the minimum quarterly distribution, plus any accrued and unpaid arrearages in the MQD from prior quarters. In addition, upon a liquidation of the partnership, common unit holders will have a preference over subordinated unit holders in certain circumstances.

If the Partnership does not consummate an initial offering within two years after the consummation of this offering, Fertilizer GP can require us to purchase its managing general partner interest in the Partnership. We may not have requisite funds to do so.

If the Partnership does not consummate an initial private or public offering within two years after the consummation of this offering, Fertilizer GP can require us to purchase the managing general partner interest. This put right expires on the earlier of (1) the fifth anniversary of the consummation of this offering and (2) the closing of the Partnership s initial offering. The purchase price will be the fair market value of the managing general partner interest, as determined by an independent investment banking firm selected by us and Fertilizer GP. Fertilizer GP will determine in its discretion whether the Partnership will consummate an initial offering.

If Fertilizer GP elects to require us to purchase the managing general partner interest, we may not have available cash resources to pay the purchase price. In addition, any purchase of the managing general partner interest would divert our capital resources from other intended uses, including capital expenditures and growth capital. In addition, the instruments governing our indebtedness may limit our ability to acquire, or prohibit us from acquiring, the managing general partner interest.

Fertilizer GP can require us to be a selling unit holder in the Partnership s initial offering at an undesirable time or price.

Under the contribution, conveyance and assumption agreement, if Fertilizer GP elects to cause the Partnership to undertake an initial private or public offering, we have agreed that Fertilizer GP may structure the initial offering to include (1) a secondary offering of interests by us or (2) a primary offering of interests by the Partnership, possibly together with an incurrence of indebtedness by the

Partnership, where a use of proceeds is to redeem units from us (with a per-unit redemption price equal to the price at which a unit is purchased from the Partnership, net of sales commissions or underwriting discounts) (a special GP offering), provided that in either case the number of units associated with the special GP offering is reasonably expected by Fertilizer GP to generate no more than $100 million in net proceeds to us. If Fertilizer GP elects to cause the Partnership to undertake an initial private or public offering, it may require us to sell (including by redemption) a portion, which could be a substantial portion, of our special units in the Partnership at a time or price we would not otherwise have chosen. A sale of special units would result in our receiving cash proceeds for the value of such units, net of sales commissions and underwriting discounts. Any such sale or redemption would likely result in taxable gain to us. See Use of the limited partnership structure involves tax risks. For example, if the Partnership is treated as a corporation for U.S. income tax purposes, this would substantially reduce the cash it has available to make distributions. In return for the receipt of the net cash proceeds, we would no longer receive quarterly distributions on the units that were sold which could negatively impact our financial position. Moreover, because we would own a smaller percentage of the total units of the Partnership after such sale or redemption, the percentage of distributions that we would receive from the Partnership would decrease. See If the Partnership completes a public offering or private placement of limited partner interests, our voting power in the Partnership would be reduced and our rights to distributions from the Partnership could be materially adversely affected.

Our rights to remove Fertilizer GP as managing general partner of the Partnership are extremely limited.

For the first five years after the consummation of this offering, Fertilizer GP may only be removed as managing general partner if at least 80% of the outstanding units of the Partnership vote for removal and there is a final, non-appealable judicial determination that Fertilizer GP, as an entity, has materially breached a material provision of the partnership agreement or is liable for actual fraud or willful misconduct in its capacity as a general partner of the Partnership. Consequently, we will be unable to remove Fertilizer GP unless a court has made a final, non-appealable judicial determination in those limited circumstances as described above. Additionally, if there are other holders of partnership interests in the Partnership, these holders may have to vote for removal of Fertilizer GP as well if we desire to remove Fertilizer GP but do not hold at least 80% of the outstanding units of the Partnership at that time.

After five years from the consummation of this offering, Fertilizer GP may be removed with or without cause by a vote of the holders of at least 80% of the outstanding units of the Partnership, including any units owned by Fertilizer GP and its affiliates, voting together as a single class. Therefore, we may need to gain the support of other unit holders in the Partnership if we desire to remove Fertilizer GP as managing general partner, if we do not hold at least 80% of the outstanding units of the Partnership.

In addition to removal, we will have a right to purchase Fertilizer GP s general partner interest in the Partnership, and therefore remove the Fertilizer GP as managing general partner, if the Partnership has not made an initial private offering or an initial public offering of limited partner interests by the fifth anniversary of the consummation of this offering.

If the managing general partner is removed without cause, it will have the right to convert its managing general partner interest, including the IDRs, into units or to receive cash based on the fair market value of the interest at the time. If the managing general partner is removed for cause, a successor managing general partner will have the option to purchase the managing general partner interest, including the IDRs, of the departing managing general partner for a cash payment equal to the fair market value of the managing general partner interest. Under all other circumstances, the departing managing general partner will have the option to require the successor managing general partner to purchase the managing general partner interest of the departing managing general partner for its fair market value. See The Nitrogen Fertilizer Limited Partnership Other Provisions of the Partnership Agreement Removal of the Managing General Partner.

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The Partnership may not have sufficient available cash to enable it to make quarterly distributions to us following establishment of cash reserves and payment of fees and expenses.

The Partnership may not have sufficient available cash each quarter to make distributions to us and other unit holders, if any. In particular:

The Partnership s managing general partner has broad discretion to establish reserves for the prudent conduct of the Partnership s business. The establishment of those reserves could result in a reduction of the Partnership s distributions.

The amount of distributions made by the Partnership and the decision to make any distribution is determined by the Partnership s managing general partner, which we do not control.

Under Section 17-607 of the Delaware Limited Partnership Act, the Partnership may not make a distribution to its unit holders if the distribution would cause its liabilities to exceed the fair value of its assets.

Although the partnership agreement requires the Partnership to distribute its available cash, the partnership agreement may be amended.

If the Partnership enters into its own credit facility in the future, the credit facility may limit the distributions which the Partnership can make. In addition, the credit facility will likely contain financial tests and covenants that the Partnership must satisfy; any failure to comply with these tests and covenants could result in the lenders prohibiting distributions by the Partnership.

The actual amount of cash available for distribution will depend on factors such as the level of capital expenditures made by the Partnership, the cost of acquisitions, if any, fluctuations in the Partnership s working capital needs, the amount of fees and expenses incurred by the Partnership, and the Partnership s ability to make working capital and other borrowings to make distributions to unit holders.

If the Partnership consummates one or more public or private offerings, because at least 40% (and potentially all) of our interest may be subordinated to common units we would be harmed if the MQD could not be paid on all units.

We have included in this prospectus unaudited pro forma information for 2006 which indicates the amount of cash which the Partnership would have had available for distribution during 2006. This pro forma information is based on numerous estimates and assumptions which we believe to be reasonable, but the Partnership s financial performance had it been in existence during 2006 could have been different from the pro forma results, perhaps materially. In particular, the pro forma data assumes a specific amount of debt and interest expense for the Partnership during 2006, but the Partnership may not be able to enter into a credit facility on terms acceptable to it or at all. Similarly, the pro forma data assumes a specific amount of selling, general and administrative expense for the Partnership, but it is difficult to estimate the actual costs that the Partnership would have incurred as a stand-alone business. Accordingly, investors should review the unaudited pro forma information, including the footnotes, together with the other information included in this prospectus, including Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations. The actual results of the Partnership may differ, possibly materially, from those presented in the pro forma information.

If we were deemed an investment company under the Investment Company Act of 1940, applicable restrictions would make it impractical for us to continue our business as contemplated and could have a material adverse effect

on our business. We may in the future be required to sell some or all of our Partnership interests in order to avoid being deemed an investment company, and such sales could result in gains taxable to the company.

In order not to be regulated as an investment company under the Investment Company Act of 1940, as amended, or the 1940 Act, unless we can qualify for an exemption, we must ensure that we are engaged primarily in a business other than investing, reinvesting, owning, holding or trading in securities (as defined in the 1940 Act) and that we do not own or acquire investment securities having a value exceeding 40% of the value of our total assets (exclusive of U.S. government securities and cash items) on an unconsolidated basis. We believe that we are not currently an investment company because our general partner interests in the Partnership should not be considered to be securities under the 1940 Act and, in any event, both our refinery business and the fertilizer business are operated through majority-owned subsidiaries. In addition, even if our general partner interests in the Partnership were considered securities or investment securities, they do not currently have a value exceeding 40% of the fair market value of our total assets on an unconsolidated basis.

However, there is a risk that we could be deemed an investment company if the SEC or a court determines that our general partner interests in the Partnership are securities or investment securities under the 1940 Act and if our Partnership interests constituted more than 40% of the value of our total assets. Currently, our interests in the Partnership constitute less than 40% of our total assets on an unconsolidated basis, but they could constitute a higher percentage of the fair market value of our total assets in the future if the value of our Partnership interests increases, the value of our other assets decreases, or some combination thereof occurs.

We intend to conduct our operations so that we will not be deemed an investment company. However, if we were deemed an investment company, restrictions imposed by the 1940 Act, including limitations on our capital structure and our ability to transact with affiliates, could make it impractical for us to continue our business as contemplated and could have a material adverse effect on our business and the price of our common stock. In order to avoid registration as an investment company under the 1940 Act, we may have to sell some or all of our interests in the Partnership at a time or price we would not otherwise have chosen. The gain on such sale would be taxable to us. We may also choose to seek to acquire additional assets that may not be deemed investment securities, although such assets may not be available at favorable prices. Under the 1940 Act, we may have only up to one year to take any such actions.

Use of the limited partnership structure involves tax risks. For example, if the Partnership is treated as a corporation for U.S. income tax purposes, this would substantially reduce the cash it has available to make distributions.

The anticipated benefit of the limited partnership structure depends largely on its treatment as a partnership for federal income tax purposes following its initial public offering. In the taxable year of an initial public offering of the Partnership, if any, and in each taxable year thereafter, current law would require the Partnership to derive at least 90% of its annual gross income from specific activities to continue to be treated as a partnership for federal income tax purposes. The Partnership may not find it possible to meet this income requirement, or may inadvertently fail to meet this income requirement. In addition, a change in current law could cause the Partnership to be treated as a corporation for federal income tax purposes without regard to its sources of income or otherwise subject it to entity-level taxation. The Partnership has not requested, and does not plan to request, a ruling from the Internal Revenue Service on this or any other matter affecting the Partnership. However, in order for the Partnership to consummate an initial public offering, the Partnership will be required to obtain an opinion of legal counsel that, based upon, among other things, customary representations by the Partnership, the Partnership will continue to be treated as a partnership for federal income tax purposes following such initial public offering. The ability of the Partnership to obtain such an opinion will depend upon a number of factors, including the state of the law at the time the Partnership seeks such an opinion and the specific facts and circumstances of the Partnership at such time. If the Partnership is unable to obtain such an opinion, the Partnership will not consummate an initial public offering and will not be able to realize the anticipated benefits of being a master limited partnership.

If the Partnership were to be treated as a corporation for federal income tax purposes, it would pay federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and would pay state income taxes at varying rates. Because such a tax would be imposed upon the Partnership as a corporation, the cash available for distribution by the Partnership to its partners, including us, would be substantially reduced. In addition, distributions by the Partnership to us would also be taxable to us (subject to the 70% or 80% dividends received deduction, as applicable, depending on the degree of ownership we have in the Partnership) and we would not be able to use our share of any tax losses of the Partnership to reduce taxes otherwise payable by us. Thus, treatment of the Partnership as a corporation could result in a material reduction in our anticipated cash flow and the after-tax return to us.

In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, beginning in 2008, the Partnership will be required to pay Texas franchise tax at a maximum effective rate of 0.7% of the Partnership s gross income apportioned to Texas in the prior year. Imposition of such a tax on the Partnership by Texas and, if applicable, by any other state will reduce the cash available for distribution by the Partnership.

In addition, the sale of the managing general partner interest of the Partnership to a newly formed entity controlled by the Goldman Sachs Funds and the Kelso Funds will be made at the fair market value of the general partner interest as of the date of transfer, as determined by our board of directors after consultation with management. Any gain on this sale by us will be subject to tax. If the Internal Revenue Service or another taxing authority successfully asserted that the fair market value at the time of sale of the managing general partner interest exceeded the sale price, we would have additional deemed taxable income, which could reduce our cash flow and adversely affect our financial results. For example, if the value of the managing general partner interest increases over time, possibly significantly because the Partnership performs well, then in hindsight the sale price might be challenged or viewed as insufficient by the Internal Revenue Service or another taxing authority.

If the Partnership consummates an initial public offering or private offering and we sell units, or our units are redeemed, in a special GP offering, or the Partnership makes a distribution to us of proceeds of the offering or debt financing, such sale, redemption or distribution would likely result in taxable gain to us. We will also recognize taxable gain to the extent that otherwise nontaxable distributions exceed our tax basis in the Partnership. The tax associated with any such taxable gain could be significant.

Additionally, when the Partnership issues units or engages in certain other transactions, the Partnership will determine the fair market value of its assets and allocate any unrealized gain or loss attributable to those assets to the capital accounts of the existing partners. As a result of this revaluation and the Partnership s adoption of the remedial allocation method under Section 704(c) of the Internal Revenue Code (i) new unitholders will be allocated deductions as if the tax basis of the Partnership s property were equal to the fair market value thereof at the time of the offering, and (ii) we will be allocated reverse Section 704(c) allocations of income or loss over time consistent with our allocation of unrealized gain or loss.

The tax allocations provided by the Partnership s partnership agreement and other tax positions the Partnership may take are complex and under certain circumstances uncertain under relevant tax laws. Furthermore, the allocations depend on valuations which may be subject to challenge by the IRS. The IRS may adopt positions with respect to tax allocations or otherwise that differ from the positions the Partnership takes. It may be necessary to resort to administrative or court proceedings to sustain the positions the Partnership takes and a court may disagree with some or all of those positions.

Control of Fertilizer GP may be transferred to an unrelated third party without our consent. The new owners of Fertilizer GP may have no interest in CVR Energy and may take actions that are not in our interest.

Fertilizer GP is currently controlled by the Goldman Sachs Funds and the Kelso Funds. Following this offering, the Goldman Sachs Funds and the Kelso Funds will also collectively own 74.2% of our common stock. However, there is no restriction in the partnership agreement on the ability of the owners of Fertilizer GP to transfer their equity interest in Fertilizer GP to an unrelated third party without our consent. If such a transfer occurred, the new equity owners of

Fertilizer GP would then be in a position to replace the board of directors of Fertilizer GP (other than the two

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directors appointed by us) and the officers of Fertilizer GP with their own choices and to influence the decisions taken by the board of directors and executive officers of Fertilizer GP. These new equity owners, directors and executive officers may take actions, subject to the specified joint management rights we have as holder of special GP rights, which are not in our interests or the interests of our stockholders. In particular, the new owners may have no economic interest in us (unlike the current owners of Fertilizer GP), which may make it more likely that they would take actions to benefit Fertilizer GP and its managing general partner interest over us and our interests in the Partnership.

The Partnership may never seek to or be able to consummate an initial public offering or one or more private placements. This could negatively impact the value and liquidity of our investment in the Partnership, which could impact the value of our common stock.

The Partnership may never seek to or be able to consummate an initial public offering or an initial private offering. Any public or private offering of interests by the Partnership would be made at the discretion of the managing general partner of the Partnership and would be subject to market conditions and to achievement of a valuation which the Partnership found acceptable. An initial public offering would be subject to SEC review of a registration statement, compliance with applicable securities laws and the Partnership s ability to list Partnership units on a national securities exchange. Similarly, any private placement to a third party would depend on the Partnership s ability to reach agreement on price and enter into satisfactory documentation with a third party. Any such transaction would also require third party approvals, including consent of our lenders under our credit facilities and the swap counterparty under our Cash Flow Swap. The Partnership may never consummate any of such transactions on terms favorable to us, or at all. If no offering by the Partnership is ever made, it could impact the value, and certainly the liquidity, of our investment in the Partnership.

If the Partnership does not consummate an initial public offering, the value of our investment in the Partnership could be negatively impacted because the Partnership would not be able to access public equity markets to fund capital projects and would not have a liquid currency with which to make acquisitions or consummate other potentially beneficial transactions. In addition, we would not have a liquid market in which to sell portions of our interest in the Partnership but rather would need to monetize our interest in a privately negotiated sale if we ever wished to create liquidity through a divestiture of our nitrogen fertilizer business.

In addition, if the Partnership does not consummate an initial public offering, we believe that the value of CVR Energy s common stock could also be affected. Because we have observed that entities structured as master limited partnerships have over recent history demonstrated significantly greater relative market valuation levels compared to corporations in the refining and marketing sector when measured as a ratio of enterprise value to EBITDA, we believe that the value of CVR Energy s common stock may be enhanced to the extent that the Partnership consummates an initial public offering, because then the public market valuation of CVR Energy s common stock would reflect the higher potential valuation of the Partnership realized in its offering. If the Partnership does not consummate an initial public offering, we believe CVR Energy s common stock may not reflect the higher potential valuation of a master limited partnership.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements. Statements that are predictive in nature, that depend upon or refer to future events or conditions or that include the words believe, expect, anticipate, intend, estimate and oth expressions that are predictions of or indicate future events and trends and that do not relate to historical matters identify forward-looking statements. Our forward-looking statements include statements about our business strategy, our industry, our future profitability, our expected capital expenditures and the impact of such expenditures on our performance, the costs of operating as a public company, our capital programs and environmental expenditures. These statements involve known and unknown risks, uncertainties and other factors, including the factors described under Risk Factors, that may cause our actual results and performance to be materially different from any future results or performance expressed or implied by these forward-looking statements. Such risks and uncertainties include, among other things:

volatile margins in the refining industry;

exposure to the risks associated with volatile crude prices;

disruption of our ability to obtain an adequate supply of crude oil;

decreases in the light/heavy and/or the sweet/sour crude oil price spreads;

refinery operating hazards and interruptions, including unscheduled maintenance or downtime, and the availability of adequate insurance coverage;

losses, damages and lawsuits related to the flood and crude oil discharge;

uncertainty regarding our ability to recover costs and losses resulting from the flood and crude oil discharge;

the failure of our new and redesigned equipment in our facilities to perform according to expectations;

interruption of the pipelines supplying feedstock and in the distribution of our products;

the seasonal nature of our petroleum business;

competition in the petroleum and nitrogen fertilizer businesses;

capital expenditures required by environmental laws and regulations;

changes in our credit profile;

the availability of adequate cash and other sources of liquidity for our capital needs;

a decline in the price of natural gas;

the cyclical nature of the nitrogen fertilizer business;

adverse weather conditions;

the supply and price levels of essential raw materials;

the volatile nature of ammonia, potential liability for accidents involving ammonia that cause severe damage to property and/or injury to the environment and human health and potential increased costs relating to transport of ammonia;

the dependence of the nitrogen fertilizer operations on a few third-party suppliers;

liabilities arising from current or future environmental contamination, including from the flood and crude oil discharge;

our limited operating history as a stand-alone company;

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our commodity derivative activities;

our dependence on significant customers;

our potential inability to successfully implement our business strategies, including the completion of significant capital programs;

the success of our acquisition strategies;

our significant indebtedness;

the dependence on our subsidiaries for cash to meet our debt obligations;

whether we will be able to amend our credit facilities on acceptable terms if the Partnership seeks to consummate a public or private offering;

the potential loss of key personnel;

labor disputes and adverse employee relations;

potential increases in costs and distraction of management resulting from the requirements of being a public company;

risks relating to evaluations of internal controls required by Section 404 of the Sarbanes-Oxley Act;

the operation of our company as a controlled company ;

new regulations concerning the transportation of hazardous chemicals, risks of terrorism and the security of chemical manufacturing facilities;

successfully defending against third-party claims of intellectual property infringement;

our ability to continue to license the technology used in our operations;

the Partnership s ability to make distributions equal to the minimum quarterly distribution or any distributions at all;

the possibility that Partnership distributions to us will decrease if the Partnership issues additional equity interests and that our rights to receive distributions will be subordinated to the rights of third party investors;

the possibility that we will be required to deconsolidate the Partnership from our financial statements in the future;

the Partnership s preferential right to pursue certain business opportunities before we pursue them;

reduction of our voting power in the Partnership if the Partnership completes a public offering or private placement;

whether we will be required to purchase the managing general partner interest in the Partnership, and whether we will have the requisite funds to do so;

the possibility that we will be required to sell a portion of our interests in the Partnership in the Partnership s initial offering at an undesirable time or price;

the ability of the Partnership to manage the nitrogen fertilizer business in a manner adverse to our interests;

the conflicts of interest faced by our senior management, which operates both our company and the Partnership, and our controlling stockholders, who control our company and the managing general partner of the Partnership;

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- limitations on the fiduciary duties owed by the managing general partner which are included in the partnership agreement;

- whether we are ever deemed to be an investment company under the 1940 Act or will need to take actions to sell interests in the Partnership or buy assets to refrain from being deemed an investment company;

- changes in the treatment of the Partnership as a partnership for U.S. income tax purposes;

- transfer of control of the managing general partner of the Partnership to a third party that may have no economic interest in us; and

- the risk that the Partnership will not consummate a public offering or private placement.

You should not place undue reliance on our forward-looking statements. Although forward-looking statements reflect our good faith beliefs, reliance should not be placed on forward-looking statements because they involve known and unknown risks, uncertainties and other factors, which may cause our actual results, performance or achievements to differ materially from anticipated future results, performance or achievements expressed or implied by such forward-looking statements. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, changed circumstances or otherwise.

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USE OF PROCEEDS

We expect to receive approximately $345.20 million of net proceeds from the sale of shares by us in this offering, after deducting underwriting discounts and commissions and the estimated expenses of the offering. We expect to use the net proceeds of this offering to repay $280 million of the term loans under our Credit Facility, and to repay all indebtedness under our $25 million unsecured facility and our $25 million secured facility. We will use the remaining net proceeds to repay indebtedness outstanding under the revolving loan facility under our Credit Facility. If the underwriters exercise their option to purchase 3,000,000 additional shares from us in full, the additional net proceeds to us would be approximately $53.28 million (and the total net proceeds to us would be approximately $398.48 million) and we intend to use such additional net proceeds in the manner described above. Any remaining net proceeds would be used for general corporate purposes.

Our subsidiary, Coffeyville Resources, LLC, entered into the Credit Facility on December 28, 2006. The term loans under the Credit Facility mature on December 28, 2013 and the revolving loans under the Credit Facility mature on December 28, 2012. The term loans under the Credit Facility bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus 2.25%, or, at the borrower s election, (b) LIBOR plus 3.25%, subject, in either case, to adjustment upon achievement of certain ratings conditions. Borrowings under the revolving loans facility (including revolving letters of credit) bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus 2.25%, or, at the borrower s election, (b) LIBOR plus 3.25%, subject, in either case, to adjustment upon achievement of certain ratings conditions. At June 30, 2007, the interest rate on the term loans under the Credit Facility was 8.35%. At June 30, 2007, $773.1 million and $40.0 million (or $20.0 million as of September 30, 2007) was outstanding under the term loans and the revolving loans, respectively, under the Credit Facility. The $775 million in net proceeds from the term loans under the Credit Facility received in December 2006 were used to repay the term loans and revolving loans under our then existing first lien credit facility, repay all amounts outstanding under our then existing second lien credit facility, pay related fees and expenses, and pay a dividend to existing members of Coffeyville Acquisition LLC in the amount of $250 million. The Credit Facility entered into in December 2006 amended and restated the then existing first lien credit facility and second lien credit facility which were originally entered into in June 2005 and which were utilized at that time in conjunction with the Subsequent Acquisition. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Debt.

Our subsidiary, Coffeyville Resources, LLC, entered into the $25 million unsecured facility and the $25 million secured facility on August 23, 2007 in order to provide us with enhanced liquidity following the flood and crude oil discharge. On the $25 million unsecured facility, interest is payable in cash, at our option, at the base rate plus 1.00% or at the reserve adjusted eurodollar rate plus 2.00%. As of September 30, 2007, $25 million was outstanding under this facility. On the $25 million secured facility, interest is payable in cash, at our option, at the base rate plus 1.00% or at the reserve adjusted eurodollar rate plus 2.00%. As of September 30, 2007, $25 million was outstanding under this facility. The maturity of each of these facilities is January 31, 2008, provided that if there has been an initial public offering on or prior to January 31, 2008, the maturity will be automatically extended to August 23, 2008.

Under the terms of our Credit Facility, this offering will be deemed a Qualified IPO. Because this offering is a Qualified IPO, the interest margin on LIBOR loans may in the future decrease from 3.25% to 2.75% (if we have credit ratings of B2/B) or 2.50% (if we have credit ratings of B1/B+). Interest on base rate loans will similarly be adjusted. In addition, because the offering is a Qualified IPO, and assuming our other credit facilities are either terminated or amended to allow the following, (1) we will be allowed to borrow an additional $225 million under the Credit Facility after June 30, 2008 to finance capital enhancement projects if we are in pro forma compliance with the financial covenants in the Credit Facility and the rating agencies confirm our ratings, (2) we will be allowed to pay an additional $35 million of dividends each year, if our corporate family ratings are at least B2

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from Moody s and B from S&P, (3) we will not be subject to any capital expenditures limitations commencing with fiscal 2009 if our total leverage ratio is less than or equal to 1.25:1 for any quarter commencing with the quarter ended December 31, 2008, and (4) at any time after March 31, 2008 we will be allowed to reduce the Cash Flow Swap to not less than 35,000 barrels a day for fiscal 2008 and terminate the Cash Flow Swap for any year commencing with fiscal 2009, so long as our total leverage ratio is less than or equal to 1.25:1 and we have a corporate family rating of at least B2 from Moody s and B from S&P.

An affiliate of Goldman, Sachs & Co. is the sole lender under the term loan facility and, accordingly, will receive all of the net proceeds of this offering that we use to repay term loans under the Credit Facility. An affiliate of Goldman, Sachs & Co. is the sole lead arranger and sole bookrunner under our $25 million unsecured facility and $25 million secured facility and, accordingly, will receive all of the net proceeds used to repay our $25 million unsecured facility and $25 million secured facility. Affiliates of Goldman, Sachs & Co., Deutsche Bank Securities Inc., Credit Suisse Securities (USA) LLC and Citibank Capital Markets Inc. are lenders under the revolving loan facility and, accordingly, will receive substantially all of the net proceeds of this offering (or net proceeds received if the underwriters exercise their option to purchase additional shares from us) used to repay such revolving loans. See Description of Our Indebtedness and the Cash Flow Swap and Underwriting.

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DIVIDEND POLICY

Following the completion of this offering, we do not anticipate paying any cash dividends in the foreseeable future. We currently intend to retain future earnings from our refinery business, if any, together with any cash distributions we receive from the Partnership, to finance operations and the expansion of our business. Any future determination to pay cash dividends will be at the discretion of our board of directors and will be dependent upon our financial condition, results of operations, capital requirements and other factors that the board deems relevant. In addition, the covenants contained in our subsidiaries credit facilities limit the ability of our subsidiaries to pay dividends to us, which limits our ability to pay dividends to our stockholders, including any amounts received from the Partnership in the form of quarterly distributions. Our ability to pay dividends also may be limited by covenants contained in the instruments governing future indebtedness that we or our subsidiaries may incur in the future. See Description of Our Indebtedness and the Cash Flow Swap.

In addition, the partnership agreement which will govern the Partnership will include restrictions on the Partnership s ability to make distributions to us. If the Partnership issues limited partner interests to third party investors, these investors will have rights to receive distributions which, in some cases, will be senior to our rights to receive distributions. In addition, the managing general partner of the Partnership will have incentive distribution rights which, over time, will give it rights to receive distributions. These provisions will limit the amount of distributions which the Partnership can make to us which will, in turn, limit our ability to make distributions to our stockholders. In addition, since the Partnership will make its distributions to Coffeyville Resources, LLC, a subsidiary of ours, our credit facilities will limit the ability of Coffeyville Resources to distribute these distributions to us. In addition, the Partnership may also enter into its own credit facility or other contracts that limit its ability to make distributions to us.

On December 28, 2006, the directors of Coffeyville Acquisition LLC approved a special dividend of $250 million to its members, including $244.7 million to companies related to the Goldman Sachs Funds and the Kelso Funds and $3.4 million to certain members of our management and a director who had previously made capital contributions to Coffeyville Acquisition LLC. See Certain Relationships and Related Party Transactions Investments in Coffeyville Acquisition LLC.

In connection with this offering, the directors of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, respectively, will approve a special dividend of $10.6 million to their members, including approximately $5.2 million to the Goldman Sachs Funds, approximately $5.1 million to the Kelso Funds and approximately $0.3 million to certain members of our management, a director and an unrelated member. The common unit holders receiving this special dividend will contribute $10.6 million collectively to Coffeyville Acquisition III LLC, which will use such amounts to purchase the managing general partner.

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CAPITALIZATION

The following table sets forth our consolidated cash and cash equivalents and capitalization as of June 30, 2007:

on an actual basis for Coffeyville Acquisition LLC; and

as adjusted to give effect to the three new credit facilities we entered into in August 2007, the sale by us of 20,000,000 shares in this offering at the initial public offering price of $19.00 per share, the use of proceeds from this offering, the Transactions, the transfer of the nitrogen fertilizer business to the Partnership, the sale of the managing general partner interest in the Partnership to a new entity owned by our controlling stockholders and senior management, the termination fee payable in connection with the termination of the management agreements in conjunction with this offering, the issuance of shares of our common stock to our chief executive officer in exchange for shares in two of our subsidiaries and the payment of a dividend to Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC.

You should read this table in conjunction with Use of Proceeds, Unaudited Pro Forma Consolidated Financial Statements, Selected Historical Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations, and the consolidated financial statements and related notes included elsewhere in this prospectus.

	As of June 30, 2007		
	Actual	As Adjusted before Underwriters Option	As Adjusted after Underwriters Option
		(in thousands)	
Cash and cash equivalents	$ 23,077	$ 61,108	$ 95,070
Debt (including current portion):			
Revolving Credit Facility(1)	40,000	19,318	
Term loan facility	773,063	493,063	493,063
$25 million secured facility			
$25 million unsecured facility			
$75 million unsecured facility			
Total debt	813,063	512,381	493,063
Minority interest in subsidiaries(2)	4,904	10,600	10,600
Management voting common units subject to redemption, 201,063 units(3)	7,795		
Members equity(3):			
Members voting common equity, 22,614,937 units	17,637		
Operating override units, 992,122 units	2,524		
Value override units, 1,984,231 units	1,532		
Total members equity	21,693		

Stockholders equity(3):					
Common stock, $0.01 par value per share, 350,000,000 shares authorized; 83,141,291 shares issued and outstanding as adjusted before underwriters option; 86,141,291 shares issued and outstanding as adjusted after underwriters option(4)			831		861
Preferred stock, $0.01 par value per share, 50,000,000 shares authorized; no shares issued and outstanding as adjusted					
Additional paid-in capital(3)			364,566		417,816
Retained earnings			(10,788)		(10,788)
Total stockholders equity			354,609		407,889
Total capitalization	$ 847,455	$	877,590	$	911,552

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(1) As of June 30, 2007, we had availability of $76.2 million under the revolving credit facility. As of September 30, 2007, we had outstanding $20.0 million of revolver borrowings and aggregate availability of $168.1 million under both the revolving credit facility and the $75 million unsecured facility.

(2) The as adjusted column gives effect to (i) the exchange of our chief executive officer s shares in two of our subsidiaries for shares of our common stock and (ii) the sale of the managing general partner interest in the Partnership.

(3) On an actual basis, the Members equity reflects the unit ownership at Coffeyville Acquisition LLC which is structured as a partnership for tax purposes. Upon completion of this offering, the reporting entity will be CVR Energy, Inc., a corporation. The ownership at Coffeyville Acquisition LLC and, after the consummation of the Transactions, Coffeyville Acquisition II LLC will not be reported, and as such, the components of Members equity do not appear in the As Adjusted column. Upon completion of this offering, common stock in CVR Energy, Inc. will be issued and reflected in Common stock in the As Adjusted column. Members equity and Management s voting common units subject to redemption will be eliminated and replaced with Stockholders equity to reflect the new corporate structure. Any difference in the total value of equity upon completion of this offering and the par value of the common stock issued will be reflected in Additional paid-in capital.

(4) The number of shares of common stock to be outstanding after the offering:

gives effect to a 628,667.20 for 1 split of our common stock;

gives effect to the issuance of 247,471 shares of our common stock to our chief executive officer in exchange for his shares in two of our subsidiaries;

gives effect to the issuance of 20,000,000 shares of our common stock in this offering;

excludes 10,300 shares of common stock issuable upon the exercise of stock options to be granted to two directors pursuant to our long-term incentive plan on the date of this prospectus;

excludes 17,500 shares of non-vested restricted stock to be awarded to two directors pursuant to our long-term incentive plan on the date of this prospectus;

includes 27,100 shares of common stock to be awarded to our employees in connection with this offering; and

assumes no exercise by the underwriters of their option to purchase up to 3,000,000 shares of common stock from us.

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DILUTION

Purchasers of common stock offered by this prospectus will suffer immediate and substantial dilution in net tangible book value per share. Our pro forma net tangible book value as of June 30, 2007, excluding the net proceeds of this offering, was approximately $(74.9) million, or approximately $(1.19) per share of common stock. Pro forma net tangible book value per share represents the amount of tangible assets less total liabilities (excluding the net proceeds of this offering), divided by the pro forma number of shares of common stock outstanding (excluding the 20,000,000 shares of common stock issued in this offering).

Dilution in net tangible book value per share represents the difference between the amount per share paid by purchasers of our common stock in this offering and the pro forma net tangible book value per share of our common stock immediately after this offering. After giving effect to the sale of 20,000,000 shares of common stock in this offering at the initial public offering price of $19.00 per share, and after deduction of the estimated underwriting discounts and commissions and estimated offering expenses payable by us, our pro forma net tangible book value as of June 30, 2007 would have been approximately $270.3 million, or $3.25 per share. This represents an immediate increase in net tangible book value of $4.44 per share of common stock to our existing stockholders and an immediate pro forma dilution of $15.75 per share to purchasers of common stock in this offering. The following table illustrates this dilution on a per share basis.

Assumed initial public offering price per share		$ 19.00
Pro forma net tangible book value per share as of June 30, 2007, excluding the net proceeds of this offering	$ (1.19)	
Pro forma increase per share attributable to new investors	$ 4.44	
Net tangible book value per share after the offering		$ 3.25
Dilution per share to new investors		$ 15.75

The following table sets forth as of June 30, 2007 the number of shares of common stock purchased or to be purchased from us, total consideration paid or to be paid and the average price per share paid by our existing stockholders and by new investors, before deducting estimated underwriting discounts and commissions and estimated offering expenses payable by us at the initial public offering price of $19.00 per share.

	Shares Purchased		Total Consideration		Average Price
	Number	Percent	Amount	Percent	Per Share
Existing stockholders(1)	63,141,291	76%	$ (2,440,000)	(1)%	$ (0.04)
New investors	20,000,000	24	380,000,000	101	19.00
Total	83,141,291	100%	$ 377,560,000	100%	$ 4.54

(1) Total consideration and average price per share paid by the existing stockholders give effect to the $250.0 million distribution made to certain of the existing stockholders in December 2006 using proceeds from the Credit Facility and the $10.6 million dividend we intend to distribute to existing stockholders in connection with the

Transactions. If the table were adjusted to not give effect to these payments, existing stockholders total consideration for their shares would be $258,160,000 with an average share price of $4.09.

If the underwriters exercise their option to purchase 3,000,000 shares from us in full, then the pro forma increase per share attributable to new investors would be $4.95, the net tangible book value per share after the offering would be $3.76 and the dilution per share to new investors would be $15.24. In addition, new investors would purchase 23,000,000 shares, or approximately 27% of shares outstanding, and the total consideration paid by new investors would increase to $437,000,000, or 101% of the total consideration paid.

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UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

CVR Energy, Inc. was incorporated in Delaware in September 2006. CVR Energy has assumed that concurrent with this offering, a newly formed direct subsidiary of CVR Energy will merge with Coffeyville Refining & Marketing Holdings, Inc. (which owns Coffeyville Refining & Marketing, Inc.) and a separate newly formed direct subsidiary of CVR Energy will merge with Coffeyville Nitrogen Fertilizers, Inc. which will make Coffeyville Refining & Marketing and Coffeyville Nitrogen Fertilizers wholly owned subsidiaries of CVR Energy. CVR Energy currently has no assets, liabilities, revenues, or financial activity of its own. It was organized in connection with and in order to consummate this offering. The pre-IPO reorganization transactions will have no financial impact on our results of operations.

In addition, prior to the consummation of this offering, we intend to transfer our nitrogen fertilizer business to a newly created limited partnership in exchange for a managing general partner interest and a special general partner interest. We intend to sell the managing general partner interest to an entity owned by our controlling stockholders and senior management at fair market value prior to the consummation of this offering.

In conjunction with our ownership of the special general partner interest, we will initially own all of the interests in the Partnership (other than the managing general partner interest and associated IDRs) and will initially be entitled to all cash that is distributed by the Partnership. The managing general partner will not be entitled to participate in Partnership distributions except in respect of associated IDRs, which entitle the managing general partner to receive increasing percentages of the Partnership s quarterly distributions if the Partnership increases its distributions above an amount specified in the partnership agreement. The Partnership will not make any distributions with respect to the IDRs until the aggregate adjusted operating surplus, as defined in the partnership agreement, generated by the Partnership during the period from its formation through December 31, 2009 has been distributed in respect of the special general partner interests, which we will hold, and/or the Partnership s common and subordinated interests (none of which are yet outstanding, but which would be issued if the Partnership issues equity in the future). In addition, there will be no distributions paid on the managing general partner s IDRs for so long as the Partnership or its subsidiaries are guarantors under our credit facilities.

The Partnership will be operated by our senior management pursuant to a services agreement to be entered into among us, the managing general partner, and the Partnership. The Partnership will be managed by the managing general partner and, to the extent described below, us, as special general partner. As special general partner of the Partnership, we will have joint management rights regarding the appointment, termination, and compensation of the chief executive officer and chief financial officer of the managing general partner, will designate two members of the board of directors of the managing general partner and will have joint management rights regarding specified major business decisions relating to the Partnership.

On December 28, 2006, our subsidiary Coffeyville Resources, LLC entered into a Credit Facility which provides financing of up to $1.075 billion. The Credit Facility consists of $775 million of tranche D term loans, a $150 million revolving credit facility, and a funded letter of credit facility of $150 million issued in support of the Cash Flow Swap. The Credit Facility refinanced the first lien and second lien credit facilities which had been amended and restated on June 29, 2006.

The unaudited pro forma condensed consolidated statements of operations of CVR Energy, Inc. for the year ended December 31, 2006 and for the six months ended June 30, 2007 have been derived from the audited consolidated statement of operations for the year ended December 31, 2006 and from the unaudited consolidated statement of operations for the six months ended June 30, 2007, respectively. The unaudited pro forma consolidated balance sheet at June 30, 2007 has been derived from the unaudited consolidated balance sheet at June 30, 2007.

The statements of operations for the year ended December 31, 2006 and for the six months ended June 30, 2007 are adjusted to give pro forma effect for the refinancing of the Credit Facility which occurred on December 28, 2006, the borrowings under the $25 million secured facility and the $25 million unsecured facility which occurred in August 2007, this offering, the use of proceeds from this offering and the Transactions, as if these transactions occurred on January 1, 2006. The unaudited consolidated balance sheet as of June 30, 2007 has been adjusted to give effect to the transfer of our nitrogen fertilizer business to the Partnership, the payment of a dividend to Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and the sale of the managing general partner interest in the Partnership to the newly formed entity owned by our controlling stockholders and senior management and the related income tax liability due to the recognition of the gain on such sale for income tax purposes, the borrowings under the $25 million secured facility and the $25 million unsecured facility which occurred in August 2007, this offering, the use of proceeds from this offering, the Transactions, the termination fee payable in connection with the termination of the management agreements with Goldman, Sachs & Co. and Kelso & Company, L.P. in conjunction with this offering and the issuance of shares of our common stock to our chief executive officer in exchange for shares in two of our subsidiaries as if these transactions had occurred on June 30, 2007.

The unaudited pro forma consolidated financial statements are provided for informational purposes only and do not purport to represent or be indicative of the results that actually would have been obtained had the transactions described above occurred on January 1, 2006 and June 30, 2007, respectively and are not intended to project our consolidated financial condition or results of operations for any future period or at any future date.

The pro forma adjustments are based on available information and certain assumptions that we believe are reasonable. The pro forma adjustments and certain assumptions are described in the accompanying notes. Other information included under this heading has been presented to provide additional analysis.

The unaudited pro forma consolidated financial statements set forth below should be read in conjunction with the historical financial statements, the related notes and Management s Discussion and Analysis of Financial Condition and Results of Operations included elsewhere in this prospectus.

CVR Energy, Inc.
Unaudited Pro Forma Condensed Consolidated Statement of Operations
For the Year Ended December 31, 2006

	Successor Year Ended December 31, 2006	Pro Forma Adjustments to Give Effect to the Refinancing and New Credit Facilities	Pro Forma Adjustment to Give Effect to Proceeds from the Offering	Pro Forma Year Ended December 31, 2006
Net Sales	$ 3,037,567,362	$	$	$ 3,037,567,362
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	2,443,374,743			2,443,374,743
Direct operating expenses (exclusive of depreciation and amortization)	198,979,983			198,979,983
	62,600,121	941,667(a)		63,541,788

Selling, general and administrative expenses (exclusive of depreciation and amortization)						
Depreciation and amortization		51,004,582				51,004,582
Total operating costs and expenses		2,755,959,429	941,667			2,756,901,096
Operating income (loss)		281,607,933	(941,667)			280,666,266
Other income (expense):						
Interest expense		(43,879,644)	(18,442,213)(b)	28,256,021(d)		(34,065,836)
Gain on derivatives		94,493,141				94,493,141
Loss on extinguishment of debt		(23,360,306)				(23,360,306)
Other income		2,550,359				2,550,359
Income (loss) before income taxes		311,411,483	(19,383,880)	28,256,021		320,283,624
Income tax expense (benefit)		119,840,160	(7,729,322)(c)	11,267,088(e)		123,377,926
Net income (loss)		191,571,323	(11,654,558)	16,988,933		196,905,698
Pro forma earnings per share, basic(f)	$	2.22			$	2.28
Pro forma earnings per share, diluted(f)	$	2.22			$	2.28
Pro forma weighted average shares, basic(f)		86,216,485				86,493,623
Pro forma weighted average shares, diluted(f)		86,233,985				86,511,123

(a) To reflect the additional increase in fees related to the refinancing transaction and the related funded letter of credit in support of the Cash Flow Swap, which are required under the terms of the senior secured credit facility refinanced on December 28, 2006.

(b) To increase the interest expense for (1) additional interest resulting from the refinancing of the Credit Facility on December 28, 2006 as if it had occurred on January 1, 2006 (an assumed average interest rate of 8.36% based on the interest rate in effect on the term loans as of December 28, 2006 was used to calculate interest expense on an average annual balance of $772 million of term debt); (2) amortization of the related deferred financing costs of $11.1 million amortized over the life of the related debt instrument; (3) additional interest resulting from the borrowings under the $25 million secured facility and the $25 million unsecured facility which occurred in August 2007, as if they had occurred on January 1, 2006 (an assumed average interest rate of 9.25% based on base rate interest in effect on August 23, 2007 was used to calculate interest expense on an average annual balance of $50 million of term debt); and (4) amortization of the related deferred financing costs of $2.0 million amortized over the life of the related debt instrument. Actual interest expense may be higher or lower depending upon fluctuations in interest rates. A 1/8% change in interest rates would have resulted in a $1,040,833 change in interest expense for the twelve month period.

(c) To reflect the income tax effect of the pro forma pre-tax loss adjustments of $(19,383,880) for the year ended December 31, 2006 using a combined federal and state statutory rate of approximately 39.875%.

(d) To reflect the reduction in interest expense related to (1) the repayment of long-term debt of $280 million from the offering proceeds as if it had occurred on January 1, 2006 (an assumed average interest rate of 8.36% based on the interest rate in effect on the term loans as of December 28, 2006 was used to calculate the adjustment to interest expense) and (2) the repayment of the $25 million unsecured facility and the $25 million secured facility from proceeds of this offering as if it had occurred on January 1, 2006. Actual interest expense may be higher or lower depending upon fluctuations in interest rates. A 1/8% change in interest rates would have resulted in a $624,980 change in interest expense for the twelve month period.

(e) To reflect the income tax effect of the pro forma pre-tax income adjustments of $28,256,021 for the year ended December 31, 2006, using a combined federal and state statutory rate of approximately 39.875%.

(f) To calculate earnings per share on a pro forma basis, based on an assumed number of shares outstanding at the time of the initial public offering. All information in this prospectus assumes that prior to the initial public offering, two newly formed direct wholly owned subsidiaries of ours will merge with Coffeyville Refinery and Marketing Holdings, Inc. (which owns Coffeyville Refining & Marketing, Inc.) and Coffeyville Nitrogen Fertilizers, Inc., we will effect a 628,667.20 for 1 stock split, 247,471 shares of our common stock will be issued to our chief executive officer in exchange for his shares in two of our subsidiaries, 27,100 shares of our common stock will be issued to our employees, 17,500 non-vested restricted shares of our common stock will be issued to two of our directors, and we will issue 20,000,000 shares of common stock in this offering. No effect has been given to any shares that might be issued in this offering by us pursuant to the exercise by the underwriters of their option to purchase additional shares in the offering. The weighted average shares outstanding also gives effect to the increase in the number of shares which, when multiplied by the initial public offering price, would be sufficient to replace the capital in excess of earnings withdrawn, as a result of our paying dividends in the year ended December 31, 2006 in excess of earnings for such period, or 3,075,194 shares. The weighted average number of shares outstanding for the pro forma column also accounts for the additional $10.6 million dividend that will be paid to Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. This excess number of shares for the pro forma column is 3,352,332 shares. The 17,500 non-vested restricted shares to be issued to two of our directors at the time of the offering are not included in the pro forma weighted average shares, basic, but are included in the pro forma weighted average shares, diluted.

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CVR Energy, Inc.
Unaudited Pro Forma Condensed Consolidated Statement of Operations
For the Six Months Ended June 30, 2007

	Successor Six Months Ended June 30, 2007	Pro Forma Adjustments to Give Effect to New Credit Facilities	Pro Forma Adjustments to Give Effect to Proceeds from the Offering	Pro Forma Six Months Ended June 30, 2007
Net sales	$ 1,233,895,912	$	$	$ 1,233,895,912
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	873,293,323			873,293,323
Direct operating expenses (exclusive of depreciation and amortization)	174,366,084			174,366,084
Selling, general and administrative expenses (exclusive of depreciation and amortization)	28,087,293			28,087,293
Costs associated with flood	2,138,942			2,138,942
Depreciation and amortization	32,192,458			32,192,458
Total operating costs and expenses	1,110,078,100			1,110,078,100
Operating income	123,817,812			123,817,812
Other income (expense):				
Interest expense	(27,619,423)	(2,293,493)(a)	14,054,320(d)	(15,858,596)
Loss on derivatives	(292,444,434)			(292,444,434)
Other income	715,550			715,550
Income (loss) before income taxes and minority interest in subsidiaries	(195,530,495)	(2,293,493)	14,054,320	(183,769,668)
Income tax expense (benefit)	(140,966,282)	(914,530)(b)	5,604,160(e)	(136,276,652)
Minority interest in (income) loss of subsidiaries	256,748	5,909(c)	(36,210)(f)	226,447
Net income (loss)	(54,307,465)	(1,373,054)	8,413,950	(47,266,569)

Pro forma loss per share, basic(g)	$	(0.65)	$	(0.57)
Pro forma loss per share, diluted(g)	$	(0.65)	$	(0.57)
Pro forma weighted average shares, basic(g)		83,141,291		83,141,291
Pro forma weighted average shares, diluted(g)		83,141,291		83,141,291

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(a) To increase the interest expense for additional interest resulting from the borrowings under the $25 million secured facility and the $25 million unsecured facility which occurred in August 2007, as if they had occurred on January 1, 2007. An assumed average interest rate of 9.25% based on base rate interest in effect on August 23, 2007 was used to calculate interest expense on an average annual balance of $50 million of term debt. Actual interest expense may be higher or lower depending upon fluctuations in interest rates. A 1/8% change in interest rates would have resulted in a $30,993 change in interest expense for the six month period.

(b) To reflect the income tax effect of the pro forma pre-tax loss adjustments of $(2,293,493) for the six months ended June 30, 2007 using a combined federal and state statutory rate of approximately 39.875%.

(c) To reflect the adjustment to minority loss in subsidiaries for the net impact of the pro forma pre-tax loss adjustments of $(2,293,493) and the related income tax effect of the adjustment.

(d) To reflect the reduction in interest expense related to (1) the repayment of long-term debt of $280 million from the offering proceeds as if it had occurred on January 1, 2007 (an assumed average interest rate of 8.35% based on the average interest rate in effect on the term loans as of June 30, 2007 was used to calculate the adjustment to interest expense) and (2) the repayment of the $25 million unsecured facility and the $25 million secured facility from proceeds of this offering as if it had occurred on January 1, 2007. Actual interest expense may be higher or lower depending upon fluctuations in interest rates. A 1/8% change in interest rates would have resulted in a $310,703 change in interest expense for the six month period.

(e) To reflect the income tax effect of the pro forma pre-tax income adjustments of $14,054,320 for the six months ended June 30, 2007 using a combined federal and state statutory rate of approximately 39.875%.

(f) To reflect the adjustment to minority loss in subsidiaries for the net impact of the pro forma pre-tax income adjustments of $14,054,320 and the related income tax effect of the adjustment.

(g) To calculate earnings per share on a pro forma basis, based on an assumed number of shares outstanding at the time of the initial public offering. All information in this prospectus assumes that prior to the initial public offering, two newly formed direct wholly owned subsidiaries of CVR Energy will merge with Coffeyville Refining & Marketing Holdings, Inc. (which owns Coffeyville Refining & Marketing, Inc.) and Coffeyville Nitrogen Fertilizer, Inc., we will effect a 628,667.20 for 1 stock split, 247,471 shares of our common stock will be issued to our chief executive officer in exchange for his shares in two of our subsidiaries, 27,100 shares of our common stock will be issued to our employees, 17,500 non-vested restricted shares of our common stock will be issued to two of our directors, and we will issue 20,000,000 shares of common stock in this offering. No effect has been given to any shares that might be issued in this offering by us pursuant to the exercise by the underwriters of their option to purchase additional shares in the offering. The 17,500 non-vested restricted shares of our common stock to be issued to two of our directors have been excluded from the calculation of pro forma diluted earnings per share because the inclusion of such shares in the number of weighted shares outstanding would be antidilutive.

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CVR Energy, Inc.
Unaudited Pro Forma Consolidated Balance Sheet at June 30, 2007

	Six Months Ended June 30, 2007	Pro Forma Adjustments	Pro Forma Six Months Ended June 30, 2007	Adjustments for Underwriters Option	Pro Forma Adjusted for Underwriters Option Six Months Ended June 30, 2007
ASSETS					
Current assets:					
Cash and cash equivalents	$ 23,077,422	$ (10,600,000)(a) 10,600,000 (b) 380,000,000 (c) (29,317,844)(d) (280,000,000)(e) (70,682,156)(f) 48,030,540 (g) (10,000,000)(h)	$ 61,107,962	$ 57,000,000 (k) (3,720,000)(l) (19,317,844)(m)	$ 95,070,118
Accounts receivable, net of allowance for doubtful accounts of $384,598	76,022,457		76,022,457		76,022,457
Inventories	179,243,439		179,243,439		179,243,439
Prepaid expenses and other current assets	23,255,906	(7,435,453)(d)	15,820,453		15,820,453
Income tax receivable	133,467,799	(4,226,750)(i)	129,241,049		129,241,049
Deferred income taxes	133,008,581		133,008,581		133,008,581
Total current assets	568,075,604	26,368,337	594,443,941	33,962,156	628,406,097
Property, plant, and equipment, net of accumulated depreciation	1,157,972,453	632,509 (j)	1,158,604,962		1,158,604,962
Intangible assets, net	535,525		535,525		535,525
Goodwill	83,774,885		83,774,885		83,774,885
Deferred financing costs, net	8,571,677	1,969,460 (g) (787,784)(f)	9,753,353		9,753,353
Other long-term assets	7,305,374		7,305,374		7,305,374
Total assets	$ 1,826,235,518	$ 28,182,522	$ 1,854,418,040	$ 33,962,156	$ 1,888,380,196

LIABILITIES AND EQUITY					
Current liabilities:					
Current portion of long-term debt	$ 7,701,683	$ (2,782,543)(e) 50,000,000 (g) (50,000,000)(f)	$ 4,919,140	$	$ 4,919,140
Revolving debt	40,000,000	(20,682,156) (f)	19,317,844	(19,317,844)(m)	
Accounts payable	138,394,089	(1,953,297)(d)	136,440,792		136,440,792
Personnel accruals	25,452,206		25,452,206		25,452,206
Accrued taxes other than income taxes	11,506,841		11,506,841		11,506,841
Payable to swap counterparty	267,118,025		267,118,025		267,118,025
Deferred revenue	1,383,699		1,383,699		1,383,699
Other current liabilities	23,024,739		23,024,739		23,024,739
Total current liabilities	514,581,282	(25,417,996)	489,163,286	(19,317,844)	469,845,442
Long-term liabilities:					
Long-term debt, less current portion	765,360,817	(277,217,457)(e)	488,143,360		488,143,360
Accrued environmental liabilities	5,612,516		5,612,516		5,612,516
Deferred income taxes	387,155,256		387,155,256		387,155,256
Payable to swap counterparty	119,133,755		119,133,755		119,133,755
Total long-term liabilities	1,277,262,344	(277,217,457)	1,000,044,887		1,000,044,887
Minority interest in subsidiaries	4,904,421	10,600,000 (b) (4,904,421)(j)	10,600,000		10,600,000
Management voting common units subject to redemption, 201,063 units issued and outstanding in 2007	7,795,213	(92,577)(a)			
Members equity:		(7,702,636)(c)			
Voting common units, 22,614,937 units issued and outstanding in 2007	17,636,575	(10,412,886)(a)			

		(7,223,689)(c)			
Management nonvoting override units, 2,976,353 units issued and outstanding in 2007	4,055,683	(94,537)(a) (3,961,146)(c)			
Total members equity	$ 21,692,258	$ (21,692,258)	$	$	$
PRO FORMA STOCKHOLDERS EQUITY					
Stockholders equity: Common stock, $0.01 par value per share, 350,000,000 shares authorized: 83,141,291 shares issued and outstanding as adjusted before underwriters option; 86,141,291 shares issued and outstanding as adjusted after underwriters option		831,413 (c)	831,413	30,000 (k)	861,413
Additional paid-in capital		(4,226,750)(i) 5,536,930 (j) 398,056,058 (c) (34,800,000)(d)	364,566,238	56,970,000 (k) (3,720,000)(l)	417,816,238
Retained earnings		(787,784)(f) (10,000,000)(h)	(10,787,784)		(10,787,784)
Total pro forma stockholders equity		354,609,867	354,609,867	53,280,000	407,889,867
Commitments and contingencies					
Total liabilities and equity	$ 1,826,235,518	$ 28,182,522	$ 1,854,418,040	$ 33,962,156	$ 1,888,380,196

(a) Reflects estimated payment of a $10.6 million dividend to Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC.

(b) Reflects gross proceeds of $10.6 million received for the sale of the managing general partner interest in the Partnership, through sale of the managing general partner, to Coffeyville Acquisition III LLC at estimated fair market value as determined by our board of directors after consultation with management.

(c) To reflect the public offering of 20,000,000 shares of common stock at the initial public offering price of $19.00 per share resulting in aggregate gross proceeds of $380.0 million, and in conjunction with the offering, to reflect the conversion from a partnership structure to a corporate structure of members equity and management voting common units subject to redemption.

(d) To reflect the payment of underwriters discounts and commissions and estimated offering expenses totaling $34.8 million of which $5.5 million had been prepaid as of June 30, 2007 and $2.0 million has been accrued as of June 30, 2007.

(e) To reflect the repayment of term debt of $280 million with the net proceeds of this offering.

(f) To reflect the repayment of the $25 million unsecured facility, the repayment of the $25 million secured facility, and the repayment of $20.7 million of the revolving credit facility with the remaining net proceeds of this offering and to reflect the write-off of the related deferred financing fees.

(g) To reflect the funded new credit facilities entered into in August 2007 along with deferred financing fees associated with the facilities.

(h) Reflects payment of a $10 million termination fee in connection with the termination of the management agreements payable to Goldman, Sachs & Co. and Kelso & Company, L.P. in conjunction with the offering.

(i) Reflects the tax liability determined at a combined federal and state statutory rate of approximately 39.875% associated with the estimated tax gain recognized on the sale of the managing general partner interest at estimated fair market value.

(j) Reflects the exchange of our chief executive officer s shares in two of our subsidiaries for shares of our common stock at fair market value, resulting in an estimated step-up in basis in our property, plant and equipment of approximately $0.6 million.

(k) To reflect the underwriters option to purchase 3,000,000 shares of common stock at the initial public offering price of $19.00 per share resulting in aggregate gross proceeds of $57.0 million.

(l) To reflect the payment of underwriters discounts and commissions totaling $3.7 million in connection with the underwriters option to purchase 3,000,000 shares of common stock.

(m) To reflect the repayment of revolving debt of $19.3 million from a portion of the remaining net proceeds of the sale of 3,000,000 shares of common stock to the underwriters.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

You should read the selected historical consolidated financial data presented below in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and the related notes included elsewhere in this prospectus.

The selected consolidated financial information presented below under the caption Statement of Operations Data for the 62-day period ended March 2, 2004, for the 304 days ended December 31, 2004, for the 174-day period ended June 23, 2005, for the 233-day period ended December 31, 2005 and for the year ended December 31, 2006 and the selected consolidated financial information presented below under the caption Balance Sheet Data as of December 31, 2005 and 2006 has been derived from our audited consolidated financial statements included elsewhere in this prospectus, which financial statements have been audited by KPMG LLP, independent registered public accounting firm. The consolidated financial information presented below under the caption Statement of Operations Data for the years ended December 31, 2002 and 2003, and the consolidated financial information presented below under the caption Balance Sheet Data at December 31, 2002, 2003 and 2004, are derived from our audited consolidated financial statements that are not included in this prospectus. The selected unaudited interim consolidated financial information presented below under the caption Statement of Operations Data presented below for the six month period ended June 30, 2006 and the six month period ended June 30, 2007, and the selected unaudited interim consolidated financial information presented below under the caption Balance Sheet Data as of June 30, 2007, have been derived from our unaudited interim consolidated financial statements, which are included elsewhere in this prospectus and have been prepared on the same basis as the audited consolidated financial statements. In the opinion of management, the interim data reflect all adjustments, consisting only of normal and recurring adjustments, necessary for a fair presentation of results for these periods. Operating results for the six month period ended June 30, 2007 are not necessarily indicative of the results that may be expected for the year ended December 31, 2007.

Prior to March 3, 2004, our assets were operated as a component of Farmland. Farmland filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code on May 31, 2002. On March 3, 2004, Coffeyville Resources, LLC completed the purchase of these assets from Farmland in a sales process under Chapter 11 of the U.S. Bankruptcy Code. See note 1 to our consolidated financial statements included elsewhere in this prospectus. As a result of certain adjustments made in connection with this acquisition, a new basis of accounting was established on the date of the acquisition and the results of operations for the 304 days ended December 31, 2004 are not comparable to prior periods.

During Original Predecessor periods, Farmland allocated certain general corporate expenses and interest expense to Original Predecessor. The allocation of these costs is not necessarily indicative of the costs that would have been incurred if Original Predecessor had operated as a stand-alone entity. Further, the historical results are not necessarily indicative of the results to be expected in future periods.

We calculate earnings per share for Successor on a pro forma basis, based on an assumed number of shares outstanding at the time of the initial public offering. All information in this prospectus assumes that in conjunction with the initial public offering, Coffeyville Refining & Marketing Holdings, Inc. (which owns Coffeyville Refining & Marketing, Inc.) and Coffeyville Nitrogen Fertilizers, Inc. will merge with two of our direct wholly owned subsidiaries, we will effect a 628,667.20 for 1 stock split, 247,471 shares of our common stock will be issued to our chief executive officer in exchange for his shares in two of our subsidiaries, 27,100 shares of our common stock will be issued to our employees, 17,500 non-vested restricted shares of our common stock will be issued to two of our directors, and we will issue 20,000,000 shares of common stock in this offering. No effect has been given to any shares that might be issued in this offering by us pursuant to the exercise by the underwriters of their option. The weighted average shares outstanding also gives effect to the increase in number of shares which, when multiplied by the initial public offering price, would be sufficient to replace the capital in excess of earnings withdrawn, as a result of our paying dividends in the year ended December 31, 2006 in excess of earnings for such period, or 3,075,194 shares.

We have omitted earnings per share data for Immediate Predecessor because we operated under a different capital structure than what we will operate under at the time of this offering and, therefore, the information is not meaningful.

We have omitted per share data for Original Predecessor because, under Farmland s cooperative structure, earnings of Original Predecessor were distributed as patronage dividends to members and associate members based on the level of business conducted with Original Predecessor as opposed to a common stockholder s proportionate share of underlying equity in Original Predecessor.

Original Predecessor was not a separate legal entity, and its operating results were included with the operating results of Farmland and its subsidiaries in filing consolidated federal and state income tax returns. As a cooperative, Farmland was subject to income taxes on all income not distributed to patrons as qualifying patronage refunds and Farmland did not allocate income taxes to its divisions. As a result, Original Predecessor periods do not reflect any provision for income taxes.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. See note 1 to our consolidated financial statements included elsewhere in this prospectus. As a result of certain adjustments made in connection with this acquisition, a new basis of accounting was established on the date of the acquisition. Since the assets and liabilities of Successor and Immediate Predecessor were each presented on a new basis of accounting, the financial information for Successor, Immediate Predecessor and Original Predecessor is not comparable.

Financial data for the 2005 fiscal year is presented as the 174 days ended June 23, 2005 and the 233 days ended December 31, 2005. Successor had no financial statement activity during the period from May 13, 2005 to June 24, 2005, with the exception of certain crude oil, heating oil, and gasoline option agreements entered into with a related party as of May 16, 2005.

	Successor	
	Six Months Ended June 30, 2006 (unaudited)	Six Months Ended June 30, 2007 (unaudited)
	(in millions, except as otherwise indicated)	
Statement of Operations Data:		
Net sales	$ 1,550.6	$ 1,233.9
Cost of product sold (exclusive of depreciation and amortization)	1,203.4	873.3
Direct operating expenses (exclusive of depreciation and amortization)	87.8	174.4
Selling, general and administrative expenses (exclusive of depreciation and amortization)	20.5	28.1
Costs associated with flood(1)		2.1
Depreciation and amortization	24.0	32.2
Operating income	$ 214.9	$ 123.8
Other income	1.4	0.7
Interest (expense)	(22.3)	(27.6)
Loss on derivatives	(126.5)	(292.4)
Income (loss) before income taxes and minority interest in subsidiaries	$ 67.5	$ (195.5)
Income tax (expense) benefit	(25.7)	141.0
Minority interest in (income) loss of subsidiaries		0.2
Net income (loss)(2)	$ 41.8	$ (54.3)
Pro forma earnings (loss) per share, basic	0.50	(0.65)
Pro forma earnings (loss) per share, diluted	0.50	(0.65)
Pro forma weighted average shares, basic	83,141,291	83,141,291
Pro forma weighted average shares, diluted	83,158,791	83,141,291
Balance Sheet Data:		
Cash and cash equivalents	127.9	23.1
Working capital	139.7	53.5
Total assets	1,406.1	1,826.2
Total debt, including current portion	508.3	813.1
Minority interest in subsidiaries(3)		4.9
Management units subject to redemption	12.2	7.8
Divisional/members equity	170.1	21.7
Other Financial Data:		
Depreciation and amortization	$ 24.0	$ 32.2
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(4)	101.0	59.0
Cash flows provided by operating activities	120.3	157.6
Cash flows (used in) investing activities	(86.2)	(214.1)
Cash flows provided by financing activities	29.0	37.6
Capital expenditures for property, plant and equipment	86.2	214.1
Key Operating Statistics:		
Petroleum Business		

Production (barrels per day)(5)	106,915	78,098
Crude oil throughput (barrels per day)(5)	94,083	71,098
Nitrogen Fertilizer Business		
Production Volume:		
Ammonia (tons in thousands)	205.6	169.0
UAN (tons in thousands)	328.3	304.6

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	Original Predecessor			Immediate Predecessor		Successor	
	Year Ended December 31, 2002	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006
	(in millions, except as otherwise indicated)						
Statement of Operations Data:							
Net sales	$ 887.5	$ 1,262.2	$ 261.1	$ 1,479.9	$ 980.7	$ 1,454.3	$ 3,037.6
Cost of product sold (exclusive of depreciation and amortization)	765.8	1,061.9	221.4	1,244.2	768.0	1,168.1	2,443.4
Direct operating expenses (exclusive of depreciation and amortization)	149.4	133.1	23.4	117.0	80.9	85.3	199.0
Selling, general and administrative expenses (exclusive of depreciation and amortization)	16.3	23.6	4.7	16.3	18.4	18.4	62.6
Depreciation and amortization	30.8	3.3	0.4	2.4	1.1	24.0	51.0
Impairment, earnings (losses) in joint ventures, and other charges(6)	(375.1)	(10.9)					
Operating income (loss)	$ (449.9)	$ 29.4	$ 11.2	$ 100.0	$ 112.3	$ 158.5	$ 281.6
Other income (expense)(7)	0.1	(0.5)		(6.9)	(8.4)	0.4	(20.8)
Interest (expense)	(11.7)	(1.3)		(10.1)	(7.8)	(25.0)	(43.9)
Gain (loss) on derivatives	(4.2)	0.3		0.5	(7.6)	(316.1)	94.5
Income (loss) before income taxes	$ (465.7)	$ 27.9	$ 11.2	$ 83.5	$ 88.5	$ (182.2)	$ 311.4
Income tax (expense) benefit				(33.8)	(36.1)	63.0	(119.8)
Net income (loss)(2)	$ (465.7)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ (119.2)	$ 191.6
Pro forma earnings per share, basic							$ 2.22
Pro forma earnings per share, diluted							2.22
Pro forma weighted average shares, basic							86,216,485
Pro forma weighted average shares, diluted							86,233,985
Historical dividends:							
Preferred per unit(8)				$ 1.50	$ 0.70		
Common per unit(8)				$ 0.48	$ 0.70		

Management common units subject to redemption							$ 3.1
Common units							$ 246.9
Balance Sheet Data:							
Cash and cash equivalents	$ 0.0	$ 0.0		$ 52.7		$ 64.7	$ 41.9
Working capital(9)	122.2	150.5		106.6		108.0	112.3
Total assets	172.3	199.0		229.2		1,221.5	1,449.5
Liabilities subject to compromise(10)	105.2	105.2					
Total debt, including current portion				148.9		499.4	775.0
Minority Interest in subsidiaries(3)							4.3
Management units subject to redemption						3.7	7.0
Divisional/members equity	49.8	58.2		14.1		115.8	76.4
Other Financial Data:							
Depreciation and amortization	$ 30.8	$ 3.3	$ 0.4	$ 2.4	$ 1.1	$ 24.0	$ 51.0
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(4)	(465.7)	27.9	11.2	49.7	52.4	23.6	115.4
Cash flows provided by (used in) operating activities	(1.7)	20.3	53.2	89.8	12.7	82.5	186.6
Cash flows (used in) investing activities	(272.4)	(0.8)		(130.8)	(12.3)	(730.3)	(240.2)
Cash flows provided by (used in) financing activities	274.1	(19.5)	(53.2)	93.6	(52.4)	712.5	30.8

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	Original Predecessor			Immediate Predecessor		Successor	
	Year Ended December 31,		62 Days Ended March 2,	304 Days Ended December 31,	174 Days Ended June 23,	233 Days Ended December 31,	Year Ended December 31,
	2002	2003	2004	2004	2005	2005	2006
	(in millions, except as otherwise indicated)						
Capital expenditures for property, plant and equipment	272.4	0.8		14.2	12.3	45.2	240.2
Key Operating Statistics:							
Petroleum Business							
Production (barrels per day)(5)(11)	84,343	95,701	106,645	102,046	99,171	107,177	108,031
Crude oil throughput (barrels per day)(5)(11)	74,446	85,501	92,596	90,418	88,012	93,908	94,524
Nitrogen Fertilizer Business							
Production Volume:							
Ammonia (tons in thousands)(5)	265.1	335.7	56.4	252.8	193.2	220.0	369.3
UAN (tons in thousands)(5)	434.6	510.6	93.4	439.2	309.9	353.4	633.1

(1) Represents the write-off of approximately $2.1 million of property, inventories and catalyst that were destroyed by the flood that occurred on June 30, 2007. See Flood and Crude Oil Discharge.

(2) The following are certain charges and costs incurred in each of the relevant periods that are meaningful to understanding our net income and in evaluating our performance due to their unusual or infrequent nature:

	Original Predecessor			Immediate Predecessor		Successor			
	Year Ended December 31,		62 Days Ended March 2,	304 Days Ended December 31,	174 Days Ended June 23,	233 Days Ended December 31,	Year Ended December 31,	Six Months Ended June 30,	
	2002	2003	2004	2004	2005	2005	2006	2006	2007
	(in millions)								
Impairment of property, plant and equipment(a)	$ 375.1	$ 9.6	$	$	$	$	$	$	$
Fertilizer lease payments(b)	0.3								
Loss on extinguishment of				7.2	8.1		23.4		

debt(c)						
Inventory fair market value adjustment(d)		3.0	16.6			
Funded letter of credit expense and interest rate swap not included in interest expense(e)			2.3		0.6	0.2
Major scheduled turnaround expense(f)	17.0	1.8		6.6	0.3	76.8
Loss on termination of swap(g)			25.0			
Unrealized (gain) loss from Cash Flow Swap			235.9	(126.8)	98.2	188.5

(a) During the year ended December 31, 2002, we recorded a $375.1 million asset impairment related to the write-down of our refinery and nitrogen fertilizer plant to estimated fair value. During the year ended December 31, 2003, we recorded an additional charge of $9.6 million related to the asset impairment of our refinery and nitrogen fertilizer plant based on the expected sales price of the assets in the Initial Acquisition.

(b) Reflects the impact of an operating lease structure utilized by Farmland to finance the nitrogen fertilizer plant which operating lease structure is not currently in use. The cost of this plant under the operating lease was $263.0 million and the rental payment was $0.3 million for the period ended December 31, 2002. In February 2002, Farmland refinanced the operating lease into a secured loan structure, which effectively terminated the lease and all of Farmland s obligations under the lease.

(c) Represents the write-off of $7.2 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on May 10, 2004, the write-off of $8.1 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on June 23, 2005 and the write-off of $23.4 million in connection with the refinancing of our senior secured credit facility on December 28, 2006.

(d) Consists of the additional cost of product sold expense due to the step up to estimated fair value of certain inventories on hand at March 3, 2004 and June 24, 2005, as a result of the allocation of the purchase price of the Initial Acquisition and the Subsequent Acquisition to inventory.

(e) Consists of fees which are expensed to Selling, general and administrative expenses in connection with the funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap. We consider these fees to be equivalent to interest expense and the fees are treated as such in the calculation of EBITDA in the Credit Facility.

(f) Represents expense associated with a major scheduled turnaround.

(g) Represents the expense associated with the expiration of the crude oil, heating oil and gasoline option agreements entered into by Coffeyville Acquisition LLC in May 2005.

(3) Minority interest reflects common stock in two of our subsidiaries owned by John J. Lipinski (which will be exchanged for shares of our common stock with an equivalent value prior to the consummation of this offering).

(4) Net income adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for the derivative transaction that was executed in conjunction with the Subsequent Acquisition. On June 16, 2005, Coffeyville Acquisition LLC entered into the Cash Flow Swap with J. Aron, a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The Cash Flow Swap was subsequently assigned by Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. The derivative took the form of three NYMEX swap agreements whereby if crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. With crude oil capacity expected to reach 115,000 bpd by the end of 2007, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of the Credit Facility and upon meeting specific requirements related to an initial public offering, our leverage ratio and our credit ratings, and assuming our other credit facilities are terminated or amended to allow such actions, we may reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010. See Description of Our Indebtedness and the Cash Flow Swap.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current GAAP. As a result, our periodic statements of operations reflect material amounts of unrealized gains and losses based on the increases or decreases in market value of the unsettled position under the swap agreements, which is accounted for as a liability on our balance sheet. As the crack spreads increase we are required to record an increase in this liability account with a corresponding expense entry to be made to our statement of operations. Conversely, as crack spreads decline we are required to record a decrease in the swap related liability and post a corresponding income entry to our statement of operations. Because of this inverse relationship between the economic outlook for our underlying business (as represented by crack spread levels) and the income impact of the unrecognized gains and losses, and given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income adjusted for gain or loss from Cash Flow Swap as a key indicator of our business performance. In managing our business and assessing its growth and profitability from a strategic and financial planning perspective, management and our Board of Directors considers our U.S. GAAP net income results as well as Net income adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income adjusted for unrealized gain or loss from Cash Flow Swap enhances the understanding of our results of operations by highlighting income attributable to our ongoing operating performance exclusive of charges and income resulting from mark to market adjustments that are not necessarily indicative of the performance of our underlying business and our industry. The adjustment has been made for the unrealized loss from Cash Flow Swap net of its related tax benefit.

Net income adjusted for gain or loss from Cash Flow Swap is not a recognized term under GAAP and should not be substituted for net income as a measure of our performance but instead should be utilized as a supplemental measure of financial performance or liquidity in evaluating our business. Because Net income adjusted for unrealized gain or loss from Cash Flow Swap excludes mark to market adjustments, the measure does not reflect the fair market value of our Cash Flow Swap in our net income. As a result, the measure does not include potential cash payments that may be required to be made on the Cash Flow Swap in the future. Also, our presentation of this non-GAAP measure may not be comparable to similarly titled measures of other companies.

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The following is a reconciliation of Net income adjusted for unrealized gain or loss from Cash Flow Swap to Net income:

	Original Predecessor			Immediate Predecessor		Successor			
	Year Ended December 31, 2002	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007
	(in millions)								
Net income (loss) adjusted for unrealized gain (loss) from Cash Flow Swap	$ (465.7)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ 23.6	$ 115.4	101.0	59.0
Plus: Unrealized gain (loss) from Cash Flow Swap, net of tax benefit						(142.8)	76.2	(59.2)	(113.3)
Net income (loss)	$ (465.7)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ (119.2)	$ 191.6	$ 41.8	$ (54.3)

(5) Barrels per day is calculated by dividing the volume in the period by the number of calendar days in the period. Barrels per day as shown here is impacted by plant down-time and other plant disruptions and does not represent the capacity of the facility s continuous operations.

(6) Includes the following:

During the year ended December 31, 2002, we recorded a $375.1 million asset impairment related to the write-down of the refinery and nitrogen fertilizer plant to estimated fair value.

During the year ended December 31, 2003, we recorded an additional charge of $9.6 million related to the asset impairment of the refinery and fertilizer plant based on the expected sales price of the assets in the Initial Acquisition. In addition, we recorded a charge of $1.3 million for the rejection of existing contracts while operating under Chapter 11 of the U.S. Bankruptcy Code.

(7) During the 304 days ended December 31, 2004, the 174 days ended June 23, 2005 and the year ended December 31, 2006, we recognized a loss of $7.2 million, $8.1 million and $23.4 million, respectively, on early extinguishment of debt.

(8) Historical dividends per unit for the 304-day period ended December 31, 2004 and the 174-day period ended June 23, 2005 are calculated based on the ownership structure of Immediate Predecessor.

(9) Excludes liabilities subject to compromise due to Original Predecessor s bankruptcy of $105.2 million as of December 31, 2002 and 2003 in calculating Original Predecessor s working capital.

(10) While operating under Chapter 11 of the U.S. Bankruptcy Code, Original Predecessor s financial statements were prepared in accordance with SOP 90-7 Financial Reporting by Entities in Reorganization under Bankruptcy Code. SOP 90-7 requires that pre-petition liabilities be segregated in the Balance Sheet.

(11) Operational information reflected for the 233-day Successor period ended December 31, 2005 includes only 191 days of operational activity. Successor was formed on May 13, 2005 but had no financial statement activity during the 42-day period from May 13, 2005 to June 24, 2005, with the exception of certain crude oil, heating oil and gasoline option agreements entered into with J. Aron as of May 16, 2005 which expired unexercised on June 16, 2005.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion and analysis of our financial condition and results of operations in conjunction with our financial statements and related notes included elsewhere in this prospectus. This discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors, including, but not limited to, those set forth under Risk Factors, Cautionary Note Regarding Forward-Looking Statements and elsewhere in this prospectus.

Overview and Executive Summary

We are an independent refiner and marketer of high value transportation fuels and, through a limited partnership in which we will initially own all of the interests (other than the managing general partner interest and associated IDRs), a producer of ammonia and UAN fertilizers. We are one of only seven petroleum refiners and marketers in the Coffeyville supply area (Kansas, Oklahoma, Missouri, Nebraska and Iowa) and, at current natural gas prices, the nitrogen fertilizer business is the lowest cost producer and marketer of ammonia and UAN in North America.

We have two business segments: petroleum and nitrogen fertilizer. For the fiscal years ended December 31, 2004, 2005 and 2006, we generated combined net sales of $1.7 billion, $2.4 billion and $3.0 billion, respectively. Our petroleum business generated $1.6 billion, $2.3 billion and $2.9 billion of our combined net sales, respectively, over these periods, with the nitrogen fertilizer business generating substantially all of the remainder. In addition, during these periods, our petroleum business contributed 76%, 74% and 87% of our combined operating income, respectively, with the nitrogen fertilizer business contributing substantially all of the remainder.

Our petroleum business includes a 113,500 bpd complex full coking sour crude refinery in Coffeyville, Kansas (with capacity expected to reach approximately 115,000 bpd by the end of 2007). In addition, supporting businesses include (1) a crude oil gathering system serving central Kansas, northern Oklahoma and southwest Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, and (3) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and at throughput terminals on Magellan s refined products distribution systems. In addition to rack sales (sales which are made at terminals into third party tanker trucks), we make bulk sales (sales through third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise and NuStar. Our refinery is situated approximately 100 miles from Cushing, Oklahoma, one of the largest crude oil trading and storage hubs in the United States, served by numerous pipelines from locations including the U.S. Gulf Coast and Canada, providing us with access to virtually any crude variety in the world capable of being transported by pipeline.

Throughput (the volume processed at a facility) at the refinery has markedly increased since July 2005. Management s focus on crude slate optimization (the process of determining the most economic crude oils to be refined), reliability, technical support and operational excellence coupled with prudent expenditures on equipment has significantly improved the operating metrics of the refinery. Historically, the Coffeyville refinery operated at an average crude throughput rate of less than 90,000 bpd. In the second quarter of 2006, the plant averaged over 102,000 bpd of crude throughput and over 94,500 bpd for 2006 with peak daily rates in excess of 113,500 bpd in June 2007. Not only were rates increased but yields were simultaneously improved. Since June 2005 the refinery has eclipsed monthly record (30 day) processing rates on approximately two thirds of the individual units on site.

Crude is supplied to our refinery through our owned and leased gathering system and by a Plains pipeline from Cushing, Oklahoma. We maintain capacity on the Spearhead Pipeline from

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Canada and receive foreign and deepwater domestic crudes via the Seaway Pipeline system. We have also committed to additional pipeline capacity on the proposed Keystone pipeline project currently under development. We also maintain leased storage in Cushing to facilitate optimal crude purchasing and blending. We have significantly expanded the variety of crude grades processed in any given month from a limited few to over a dozen, including onshore and offshore domestic grades, various Canadian sours, heavy sours and sweet synthetics, and a variety of South American and West African imported grades. As a result of the crude slate optimization, we have improved the crude purchase cost discount to WTI from $3.33 per barrel in 2005 to $4.75 per barrel in 2006. The crude purchase cost discount to WTI was $5.16 per barrel in the six months ended June 30, 2006 and $4.58 per barrel in the six months ended June 30, 2007.

Prior to July 2005, we did not maintain shipper status on the Magellan pipeline system. Instead, rack marketing was limited to our owned terminals. While we still rack market at our own terminals, our growing rack marketing network sells approximately 23% of produced transportation fuels at enhanced margins. For 2006, we improved net income on rack sales compared to alternative pipeline bulk sales that occurred in 2005.

The nitrogen fertilizer business in Coffeyville, Kansas includes a unique pet coke gasification facility that produces high purity hydrogen which in turn is converted to ammonia at a related ammonia synthesis plant. Ammonia is further upgraded into UAN solution in a related UAN plant. Pet coke is a low value by-product of the refinery coking process. On average more than 80% of the pet coke consumed by the fertilizer plant is produced by our refinery.

The nitrogen fertilizer business is the lowest cost producer of ammonia and UAN in North America, assuming natural gas prices remain at current levels. The fertilizer plant is the only commercial facility in North America utilizing a coke gasification process to produce nitrogen fertilizers. Its redundant train gasifier provides exceptional on-stream reliability and the use of low cost by-product pet coke feed (rather than natural gas) to produce hydrogen provides the facility with a significant competitive advantage due to high and volatile natural gas prices. The plant s competition utilizes natural gas to produce ammonia. Continual operational improvements resulted in producing nearly 750,000 tons of product in 2006, despite it being a turnaround year. Recently, the first phase of a planned expansion successfully resulted in further output. The Partnership is also considering a $50 million fertilizer plant expansion, which we estimate could increase the plant s capacity to upgrade ammonia into premium priced UAN by 50% to approximately 1,000,000 tons per year. This project is also expected to improve the cost structure of the nitrogen fertilizer business by eliminating the need for rail shipments of ammonia, thereby reducing the risks associated with such rail shipments and avoiding anticipated cost increases in such transport.

Management has identified and developed several significant capital projects since June 2005 with a total cost of approximately $522 million (including $172 million in expenditures and $3.7 million in capitalized interest for our refinery expansion project), the majority of which has already been spent. We have completed most of these capital projects and expect to complete substantially all of the capital projects by the end of 2007. Major projects include construction of a new diesel hydrotreater, a new continuous catalytic reformer, a new sulfur recovery unit, a new plant-wide flare system, a technology upgrade to the fluid catalytic cracking unit and a refinery-wide capacity expansion. The spare gasifier at the fertilizer plant was expanded and it is expected that ammonia production will increase by at least 6,500 tons per year. Once completed, these projects are intended to significantly enhance the profitability of the refinery in environments of high crack spreads and allow the refinery to operate more profitably at lower crack spreads than is currently possible.

Factors Affecting Comparability

Our results over the past three years have been and our future results will be influenced by the following factors, which are fundamental to understanding comparisons of our period-to-period financial performance.

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Acquisitions

On March 3, 2004, Coffeyville Resources, LLC completed the acquisition of the former Farmland petroleum division and one facility within Farmland s eight-plant nitrogen fertilizer manufacturing and marketing division. As a result, financial information as of and for the periods prior to March 3, 2004 discussed below and included elsewhere in this prospectus was derived from the financial statements and reporting systems of Farmland. Prior to March 3, 2004, Farmland s petroleum division was primarily comprised of our current petroleum business. The nitrogen fertilizer plant, however, was the only coke gasification facility within Farmland s eight-plant nitrogen fertilizer manufacturing and marketing division.

A new basis of accounting was established on the date of the Initial Acquisition and, therefore, the financial position and operating results after March 3, 2004 are not consistent with the operating results before the Initial Acquisition date. However, management believes the most meaningful way to comment on the statement of operations data due to the short period from January 1, 2004 to March 2, 2004 is to compare the sum of the operating results for both periods in 2004 with the sum of the operating results for both periods in 2005. Management believes it is not practical to comment on the cash flows from operating activities in the same manner because the Initial Acquisition resulted in some comparisons not being meaningful. For instance, we did not assume the accounts receivable or the accounts payable of Farmland. Farmland collected and made payments on these accounts after March 3, 2004, and these transactions are not included in our consolidated statements of cash flows.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. As a result of certain adjustments made in connection with this acquisition, a new basis of accounting was established on the date of the acquisition and the results of operations for the 233 days ended December 31, 2005 are not comparable to prior periods. In connection with the acquisition, Coffeyville Resources, LLC entered into a series of commodity derivative contracts, the Cash Flow Swap, in the form of three long-term swap agreements. With crude oil capacity expected to reach 115,000 bpd by the end of 2007, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of the Credit Facility and upon meeting specific requirements related to an initial public offering, our leverage ratio and our credit ratings, and assuming our other credit facilities are terminated or amended to allow such actions, we may reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under Statement of Financial Accounting Standards, or SFAS, No. 133, *Accounting for Derivative Instruments and Activities.* Therefore, in the financial statements for all periods after July 1, 2005, the statement of operations reflects all the realized and unrealized gains and losses from this swap. For the 233 day period ending December 31, 2005, we recorded realized and unrealized losses of $59.3 million and $235.9 million, respectively. For the year ending December 31, 2006, we recorded net realized losses of $46.8 million and net unrealized gains of $126.8 million. For the six months ended June 30, 2007, we recorded net realized losses of $97.2 million and net unrealized losses of $188.5 million.

Original Predecessor Corporate Allocations

Our financial statements prior to March 3, 2004 reflect an allocation of certain general corporate expenses of Farmland, including general and corporate insurance, property insurance, corporate retirement and benefits, human resource and payroll department salaries, facility costs, information services, and information systems support. For the year ended December 31, 2003 and for the 62-day period ended March 2, 2004, these costs allocated to our businesses were approximately $12.7 million and $3.9 million, respectively. Our financial statements prior to March 3, 2004 also reflect an allocation of interest expense from Farmland. These allocations were made by Farmland on a basis deemed meaningful for their internal management needs and may not be representative of the

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actual expense levels required to operate the businesses at that time or as they have been operated after March 3, 2004. With the exception of insurance, the net impact to our financial statements as a result of these allocations is higher selling, general and administrative expense for the period from January 1, 2003 to March 2, 2004. Our insurance costs are greater now as compared to the period prior to March 3, 2004, as we have elected to obtain additional insurance coverage that had not been carried by Farmland. Examples of this additional insurance coverage are business interruption insurance and a remediation cost cap policy related to assumed RCRA corrective orders related to contamination at or that originated from our refinery and the Phillipsburg terminal. The preceding examples and other coverage changes resulted in additional insurance costs for us.

Asset Impairments

In December 2002, Farmland implemented SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, resulting in a reorganization expense from the impairment of long-lived assets. Under this Statement, recoverability of assets to be held and used is measured by comparison of the carrying amount of an asset to the estimated undiscounted future net cash flows expected to be generated by the asset. It was determined that the carrying amount of the petroleum assets and the carrying amount of the nitrogen fertilizer plant in Coffeyville exceeded their estimated future undiscounted net cash flow. Impairment charges of $144.3 million and $230.8 million were recognized for each of the refinery and fertilizer assets, based on Farmland s best assumptions regarding the use and eventual disposition of those assets, primarily from indications of value received from potential bidders through the bankruptcy sale process. In 2003, as a result of receiving a bid from Coffeyville Resources, LLC in the bankruptcy court s sales process, Farmland revised its estimate for the amount to be generated from the disposition of these assets, and an additional impairment charge was taken. The charge to earnings in 2003 was $3.9 million and $5.7 million, respectively, for the refinery and fertilizer assets.

Original Predecessor Agreements with CHS, Inc. and Agriliance, LLC

In December 2001, Farmland entered into an agreement to sell to CHS, Inc. all of Farmland s refined products produced at the Coffeyville refinery through November 2003. The selling price for this production was set by reference to daily market prices within a defined geographic region. Subsequent to the expiration of the CHS agreement, the petroleum business began marketing its refined products in the open market to multiple customers.

The revenue received by the petroleum business under the CHS agreement was limited due to the pricing formula and product mix. From December 2001 through November 2003, under the CHS agreement, both sales of bulk pipeline shipments and truckload quantities at the Coffeyville truck rack were priced at Group III Platts Low. Currently, all sales at the Coffeyville truck rack are sold at the Platts mean price or higher. Our term contracted bulk product sales are priced between the Platts low and Platts mean prices. All other bulk sales are sold at spot market prices. In addition, we are selling several value added products that were not produced under the CHS agreement.

For the period ending December 31, 2003 and the first 62 days of 2004, Farmland s sales of nitrogen fertilizer products were subject to a marketing agreement with Agriliance, LLC. Under the agreement, Agriliance, LLC was responsible for marketing substantially all of the nitrogen made by Farmland on a basis deemed meaningful to their internal management. Following the Initial Acquisition, we began marketing nitrogen fertilizer products directly to distributors and dealers. As a result, we have been able to generate higher average netbacks on sales of fertilizer products as a percentage of market average prices. For example, in 2004 we generated average netbacks as a percentage of market averages of 90.1% and 80.2% for ammonia and UAN, respectively, compared to average netbacks as a percentage of market averages of 86.6% and 75.9% for ammonia and UAN, respectively, in 2003. The definition of the term netback is contained in the section of this prospectus entitled Glossary of Selected Terms.

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Refinancing and Prior Indebtedness

At March 3, 2004, Immediate Predecessor entered into an agreement with a financial institution for a term loan of $21.9 million with an interest rate based on the greater of the Index Rate (the greater of prime or the federal funds rate plus 50 basis points per year) plus 4.5% or 9% and a $100 million revolving credit facility with interest at the borrower s election of either the Index Rate plus 3% or LIBOR plus 3.5%. Amounts totaling $21.9 million of the term loan borrowings and $38.8 million of the revolving credit facility were used to finance the Initial Acquisition on March 3, 2004 as described above. Outstanding borrowings on May 10, 2004 were repaid in connection with the refinancing described below.

Effective May 10, 2004, Immediate Predecessor entered into a term loan of $150 million and a $75 million revolving loan facility with a syndicate of banks, financial institutions, and institutional lenders. Both loans were secured by substantially all of Immediate Predecessor s real and personal property, including receivables, contract rights, general intangibles, inventories, equipment, and financial assets. The covenants contained under the new term loan contained restrictions which limited the ability to pay dividends at the complete discretion of the Board of Directors. The Immediate Predecessor had no other restrictions on its ability to make dividend payments. Once any debt requirements were met, any dividends were at the discretion of the Board of Directors. There were outstanding borrowings of $148.9 million under the term loan and less than $0.1 million under the revolving loan facility at December 31, 2004. Outstanding borrowings on June 23, 2005 were repaid in connection with the Subsequent Acquisition as described above.

Effective June 24, 2005, Coffeyville Resources, LLC entered into a first lien credit facility and a second lien credit facility. The first lien credit facility was in an aggregate amount not to exceed $525 million, consisting of $225 million tranche B term loans; $50 million of delayed draw term loans available for the first 18 months of the agreement and subject to accelerated payment terms; a $100 million revolving loan facility; and a funded letter of credit facility (funded facility) of $150 million for the benefit of the Cash Flow Swap provider. The first lien credit facility was secured by substantially all of Coffeyville Resources, LLC s assets. In June 2006 the first lien credit facility was amended and restated and the $225 million of tranche B term loans were refinanced with $225 million of tranche C term loans. At September 30, 2006, $222.8 million of tranche C term loans was outstanding, $30 million of delayed draw term loans was outstanding and there was $93.6 million available under the revolving loan facility. At September 30, 2006, Coffeyville Resources, LLC had $150 million in a funded letter of credit outstanding to secure payment obligations under derivative financial instruments. The second lien credit facility was a $275 million term loan facility secured by substantially all of Coffeyville Resources, LLC s assets on a second priority basis.

On December 28, 2006, Coffeyville Resources, LLC entered into a new credit facility and used the proceeds thereof to repay its then existing first lien credit facility and second lien credit facility, and to pay a dividend to the members of Coffeyville Acquisition LLC. The credit facility provides financing of up to $1.075 billion, consisting of $775 million of tranche D term loans, a $150 million revolving credit facility, and a funded letter of credit facility of $150 million issued in support of the Cash Flow Swap. The credit facility is secured by substantially all of Coffeyville Resources, LLC s assets. See Description of Our Indebtedness and the Cash Flow Swap.

In August 2007, our subsidiaries entered into a $25 million secured facility, a $25 million unsecured facility and a $75 million unsecured facility. For a discussion of these credit facilities, see Liquidity and Capital Resources Debt.

Public Company Expenses

We expect that our general and administrative expenses will increase due to the costs of operating as a public company, such as increases in legal, accounting and compliance, insurance premiums, and investor relations. We estimate that the increase in these costs will total approximately $2.5 million to $3.0 million on an annual basis excluding the costs associated with this offering and the costs of the initial implementation of our Sarbanes-Oxley Section 404 internal controls review and testing. Our financial statements following this offering will reflect the impact of these expenses and will affect the comparability with our financial statements of periods prior to the completion of this offering.

Changes in Legal Structure

Original Predecessor was not a separate legal entity, and its operating results were included within the operating results of Farmland and its subsidiaries in filing consolidated federal and state income tax returns. As a cooperative, Farmland was subject to income taxes on all income not distributed to patrons as qualified patronage refunds, and Farmland did not allocate income taxes to its divisions. As a result, the accompanying Original Predecessor financial statements do not reflect any provision for income taxes.

2007 Turnaround

In April 2007, we completed a turnaround of our refining plant at a total cost of approximately $81 million. The refinery processed crude until February 11, 2007 at which time a staged shutdown of the refinery began. The refinery recommenced operations on March 22, 2007 and continually increased crude oil charge rates until all of the key units were restarted by April 23, 2007. Additional capital expenditures of approximately $20 million will be required to finish the expansion projects currently scheduled for completion in 2008, which include, among others, construction of our new continuous catalytic reformer. Management expects that completion of these projects will increase the refinery processing capacity to approximately 115,000 bpd of crude oil by the end of 2007. The turnaround had a significant adverse impact on our first quarter financial results and had a significant but smaller adverse impact on our second quarter financial results.

2007 Flood and Crude Oil Discharge

During the weekend of June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville. Our refinery and the nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded, sustained major damage and required extensive repairs. The total third party cost to repair the refinery is currently estimated at approximately $86 million, and the total third party cost to repair the nitrogen fertilizer facility is currently estimated at approximately $4 million.

As a result of the flooding, our refinery and nitrogen fertilizer facilities stopped operating on June 30, 2007. The refinery started operating its reformer on August 6, 2007 and began to charge crude oil to the facility on August 9, 2007. Substantially all of the refinery s units were in operation by August 20, 2007. The nitrogen fertilizer facility, situated on slightly higher ground, sustained less damage than the refinery. The nitrogen fertilizer facility initiated startup at its production facility on July 13, 2007.

In addition, despite our efforts to secure the refinery prior to its evacuation as a result of the flood, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007. We are currently remediating the contamination caused by the crude oil discharge. We estimate that the total costs of oil remediation through completion will be approximately $7 million to $10 million, and that the total cost to resolve third party property damage claims will be approximately $25 million to $30 million. As a result, the total cost associated with remediation and property damage claims resolution is estimated to be approximately $32 million to $40 million. This estimate does not include potential fines or penalties which may be imposed by regulatory authorities or costs arising from potential natural resource damages claims (for which we are unable to estimate a range of possible costs at this time) or possible additional damages arising from class action lawsuits related to the flood.

Our results for the six months ended June 30, 2007 include pretax costs of $2.1 million associated with the flood, including primarily write-offs of property and inventories that are uninsured

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due to our insurance deductibles. Additional costs will be recorded in future periods as they are incurred primarily related to the repair and clean up efforts. We will evaluate the extent to which future write-offs can be recovered under our insurance policies.

The flood and crude oil discharge will have a significant adverse impact on our third quarter financial results. We expect that we will report reduced revenue due to the closure of our facilities for a portion of the third quarter, as well as significant costs related to the flood as a result of the necessary repairs to our facilities and environmental remediation. See Prospectus Summary Our Business Flood and Crude Oil Discharge.

Nitrogen Fertilizer Limited Partnership

Prior to the consummation of this offering, we will transfer our nitrogen fertilizer business to the Partnership and will sell the managing general partner interest in the Partnership to a new entity owned by our controlling stockholders and senior management. We will initially own all of the interests in the Partnership (other than the managing general partner interest and associated IDRs), and will initially be entitled to all cash that is distributed by the Partnership. The Partnership will be operated by our senior management pursuant to a services agreement to be entered into among us, the managing general partner and the Partnership. The Partnership will be managed by the managing general partner and, to the extent described below, us, as special general partner. As special general partner of the Partnership, we will have joint management rights regarding the appointment, termination and compensation of the chief executive officer and chief financial officer of the managing general partner, will designate two members to the board of directors of the managing general partner and will have joint management rights regarding specified major business decisions relating to the Partnership.

We intend to consolidate the Partnership for financial reporting purposes. We have determined that upon the sale of the managing general partner interest to an entity owned by our controlling stockholders and senior management, the Partnership will be a variable interest entity, or VIE, under the provisions of FASB Interpretation No. 46R *Consolidation of Variable Interest Entities*, or FIN No. 46R.

Using criteria in FIN 46R, management has determined that we are the primary beneficiary of the Partnership, although 100% of the managing general partner interest will be owned by a new entity owned by our controlling stockholders and senior management outside our reporting structure. Since we are the primary beneficiary, the financial statements of the Partnership will remain consolidated in our financial statements. The managing general partner s interest will be reflected as a minority interest on our balance sheet.

The conclusion that we are the primary beneficiary of the Partnership and required to consolidate the Partnership as a variable interest entity is based upon the fact that substantially all of the expected losses will be absorbed by the special general partner. Additionally, substantially all of the equity investment at risk is being contributed on behalf of the special general partner, with nominal amounts being contributed by the managing general partner. The special general partner is also expected to receive the majority, if not substantially all, of the expected returns of the Partnership through the Partnership s cash distribution provisions.

We will need to reassess from time to time whether we remain the primary beneficiary of the Partnership in order to determine if consolidation of the Partnership remains appropriate on a going forward basis. Should we determine that we are no longer the primary beneficiary of the Partnership, we will be required to deconsolidate the Partnership in our financial statements for accounting purposes on a going forward basis. In that event, we would be required to account for our investment in the Partnership under the equity method of accounting, which would affect our reported amounts of consolidated revenues, expenses and other income statement items.

The principal events that would require the reassessment of our accounting treatment related to our interest in the Partnership include:

a sale of some or all of our partnership interests to an unrelated party;

a sale of the managing general partner interest to a third party;

the issuance by the Partnership of partnership interests to parties other than us or our related parties; and

the acquisition by us of additional partnership interests (either new interests issued by the Partnership or interests acquired from unrelated interest holders).

In addition, we would need to reassess our consolidation of the Partnership if the Partnership s governing documents or contractual arrangements are changed in a manner that reallocates between us and other unrelated parties either (1) the obligation to absorb the expected losses of the Partnership or (2) the right to receive the expected residual returns of the Partnership.

Industry Factors

Petroleum Business

Earnings for our petroleum business depend largely on refining industry margins, which have been and continue to be volatile. Crude oil and refined product prices depend on factors beyond our control. While it is impossible to predict refining margins due to the uncertainties associated with global crude oil supply and global and domestic demand for refined products, we believe that refining margins for U.S. refineries will generally remain above those experienced in the period from and including 1998 through 2003 as growth in demand for refining products in the United States, particularly transportation fuels, continues to exceed the ability of domestic refiners to increase capacity. In addition, changes in global supply and demand and other factors have constricted the extent to which product importation to the United States can relieve domestic supply deficits. This phenomenon is more pronounced in our marketing region, where demand for refined products exceeded refining production by approximately 22% in 2006.

During 2004, the market price of distillates (primarily No. 1 diesel fuel and kerosene) relative to crude oil was above average due to low industry inventories and strong consumer demand brought about by the relatively cold winter weather in the Midwest and high natural gas prices. In addition, gasoline margins were above average, and substantially so during the spring and summer driving seasons, primarily because of very low pre-driving season inventories exacerbated by high demand growth. The increased demand for refined products due to the relatively cold winter and the decreased supply due to high turnaround activity led to increasing refining margins during the early part of 2004. The key event of 2005 to our industry was the hurricane season which produced a record number of named storms. The location and intensity of these storms caused significant disruption to both crude and natural gas production as well as extensive disruption to many U.S. Gulf Coast refinery operations. These events caused both price spikes in the commodity markets as well as substantial increases in crack spreads. The U.S. Gulf Coast refining market was most affected, which then led to very strong margins in the Group 3 market as the U.S. Gulf Coast refined products were not being shipped north. In addition, several environmental mandates took effect in 2005 and 2006, such as the banning of Methyl Tertiary Butyl Ether, or MTBE (an ether produced from the reaction of isobutylene and methanol specifically for use as a gasoline blendstock), in the gasoline pool and initial implementation of the reduced sulfur requirements on diesel fuels, which caused price fluctuations due to logistical and supply/demand implications. 2006 showed marked increases in crack spreads over 2005 despite a minor hurricane season. Ultra Low Sulfur Diesel, or ULSD, premiums further boosted distillate product margins and thus crack spreads in 2006. Transportation fuels product demand continued to exceed production in the Coffeyville Marketing Area. This favorable supply/demand relationship resulted in strong product commodity prices in the petroleum industry during 2006.

Average discounts for sour and heavy sour crude oil compared to sweet crude increased in 2005 and 2006 from already favorable 2004 levels due to increasing worldwide production of sour and heavy sour crude oil relative to the worldwide production of light sweet crude oil coupled with the continuing demand for light sweet crude oil. In 2004, the average discount for West Texas Sour, or WTS, compared to WTI widened to $3.96 per barrel and again in 2005 to $4.73. With the newly discovered deepwater Gulf of Mexico production combined with the introduction of Canadian sours to the mid-continent this sweet/sour spread continues to exceed average historic levels, as evidenced by the average discount of $5.36 per barrel for 2006 and $4.42 per barrel for the six months ended June 30, 2007. WTI also continues to trade at a premium to WTS due to continued high demand for sweet crude oil resulting from the more stringent fuel specifications implemented both in the United States and globally. We continue to recognize significant benefits from our ability to meet current fuel specifications using predominantly heavy and medium sour crude oil feedstocks to the extent the discount for heavy and medium sour crude oil compared to WTI continues at its current level.

Nitrogen Fertilizer Business

Earnings for the nitrogen fertilizer business depend largely on the prices of nitrogen fertilizer products, the floor price of which is directly influenced by natural gas prices. Natural gas prices have been and continue to be volatile.

Currently, the nitrogen fertilizer market is driven by an almost unprecedented increase in demand. According to the United States Department of Agriculture, U.S. farmers planted 92.9 million acres of corn in 2007, exceeding the 2006 planted area by 19 percent. This increase in acres planted in the U.S. was driven in part by ethanol demand. In addition to the increase in U.S. nitrogen fertilizer demand, global demand has increased due to overall market growth in countries such as India, Latin America and Russia.

Total world ammonia capacity has been growing. Virtually all of the net growth has been in China and is attributable to China maintaining its self-sufficiency with regards to ammonia. Excluding China and the former Soviet Union, the trend in net ammonia capacity has been essentially flat since the late 1990s, as new plant construction has been offset by plant closures in countries with high-cost feedstocks. The high cost of capital is also limiting capacity increase. Today s strong market growth appears to be readily absorbing the latest capacity additions.

Factors Affecting Results

Petroleum Business

In our petroleum business, earnings and cash flow from operations are primarily affected by the relationship between refined product prices and the prices for crude oil and other feedstocks. Feedstocks are petroleum products, such as crude oil and natural gas liquids, that are processed and blended into refined products. The cost to acquire feedstocks and the price for which refined products are ultimately sold depend on factors beyond our control, including the supply of, and demand for, crude oil, as well as gasoline and other refined products which, in turn, depend on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and the extent of government regulation. While our net sales fluctuate significantly with movements in crude oil prices, these prices do not generally have a direct long-term relationship to net income. Because we apply first-in, first-out, or FIFO, accounting to value our inventory, crude oil price movements may impact net income in the short term because of instantaneous changes in the value of the minimally required, unhedged on hand inventory. The effect of changes in crude oil prices on our results of operations is influenced by the rate at which the prices of refined products adjust to reflect these changes.

Feedstock and refined product prices are also affected by other factors, such as product pipeline capacity, local market conditions and the operating levels of competing refineries. Crude oil costs and the prices of refined products have historically been subject to wide fluctuations. An expansion or upgrade of our competitors facilities, price volatility, international political and economic developments and other factors beyond our control are likely to continue to play an important role in refining industry economics. These factors can impact, among other things, the level of inventories in the market, resulting in price volatility and a reduction in product margins. Moreover, the refining industry typically experiences seasonal fluctuations in demand for refined products, such as increases in the demand for gasoline during the summer driving season and for home heating oil during the winter, primarily in the Northeast. For further details on the economics of refining, see Industry Overview Oil Refining Industry.

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In order to assess our operating performance, we compare our net sales, less cost of product sold (refining margin), against an industry refining margin benchmark. The industry refining margin is calculated by assuming that two barrels of benchmark light sweet crude oil is converted, or cracked, into one barrel of conventional gasoline and one barrel of distillate. This benchmark is referred to as the 2-1-1 crack spread. Because we calculate the benchmark margin using the market value of NYMEX gasoline and heating oil against the market value of NYMEX WTI (WTI) crude oil (West Texas Intermediate crude oil, which is used as a benchmark for other crude oils), we refer to the benchmark as the NYMEX 2-1-1 crack spread, or simply, the 2-1-1 crack spread. The 2-1-1 crack spread is expressed in dollars per barrel and is a proxy for the per barrel margin that a sweet crude refinery would earn assuming it produced and sold the benchmark production of conventional gasoline and distillate.

Although the 2-1-1 crack spread is a benchmark for our refinery margin, because our refinery has certain feedstock costs and/or logistical advantages as compared to a benchmark refinery and our product yield is less than total refinery throughput, the crack spread does not account for all the factors that affect refinery margin. Our refinery is able to process a blend of crude oil that includes quantities of heavy and medium sour crude oil that has historically cost less than WTI crude oil. We measure the cost advantage of our crude oil slate by calculating the spread between the price of our delivered crude oil to the price of WTI crude oil, a light sweet crude oil. The spread is referred to as our consumed crude differential. Our refinery margin can be impacted significantly by the consumed crude differential. Our consumed crude differential will move directionally with changes in the WTS differential to WTI and the Maya differential to WTI as both these differentials indicate the relative price of heavier, more sour slate to WTI. The correlation between our consumed crude differential and published differentials will vary depending on the volume of light medium sour crude and heavy sour crude we purchase as a percent of our total crude volume and will correlate more closely with such published differentials the heavier and more sour the crude oil slate. The WTI less Maya crude oil differential was $15.67 and $14.99 per barrel, for the years ended December 31, 2005 and 2006, respectively, compared to $15.88 and $11.20 per barrel for the six months ended June 30, 2006 and 2007, respectively. The WTI less WTS crude oil differential was $4.73 and $5.36 per barrel for the years ended December 31, 2005 and 2006, respectively, and $5.87 and $4.42 per barrel for the six months ended June 30, 2006 and 2007, respectively. The Company s consumed crude differential increased to $4.54 per barrel for the year ended December 31, 2006 from $3.28 per barrel for the comparable period in 2005 and decreased to $4.53 for the six months ended June 30, 2007 from $5.39 for the same period in 2006. The consumed crude differential for the first half of 2007 is not comparable to prior periods due to the refinery-wide turnaround we undertook in the first quarter of 2007.

We produce a high volume of high value products, such as gasoline and distillates. We benefit from the fact that our marketing region consumes more refined products than it produces so that the market prices of our products have to be high enough to cover the logistics cost for U.S. Gulf Coast refineries to ship into our region. The result of this logistical advantage and the fact the actual product specification used to determine the NYMEX is different from the actual production in the refinery, is that prices we realize are different than those used in determining the 2-1-1 crack spread. The difference between our price and the price used to calculate the 2-1-1 crack spread is referred to as gasoline PADD II, Group 3 vs. NYMEX basis, or gasoline basis, and heating oil PADD II, Group 3 vs. NYMEX basis, or heating oil basis. Both gasoline and heating oil basis are greater than zero, which represents that prices in our marketing area exceeds those used in the 2-1-1 crack spread. Since 2003, the heating oil basis has been positive in all periods presented including an increase to $7.42 per barrel for 2006 from $3.20 per barrel for 2005. The increase for 2006 was significantly impacted by the introduction of Ultra Low Sulfur Diesel, which provides significant tax benefits. Gasoline basis for 2006 was $1.52 per barrel compared to ($0.53) per barrel for 2005. Beginning January 1, 2007, the benchmark used for gasoline will change from Reformulated Gasoline (RFG) to Reformulated Blend for Oxygenate Blend (RBOB). Given that RBOB has limited historical information the change to RBOB from RFG may have an unfavorable impact on our gasoline basis compared to the historical numbers presented.

Our direct operating expense structure is also important to our profitability. Major direct operating expenses include energy, employee labor, maintenance, contract labor, and environmental compliance. Our predominant variable cost is energy and the most important benchmark for energy costs is the value of natural gas. Our predominant variable of direct operating expense is largely energy related and therefore sensitive to the movements of natural gas prices.

Consistent, safe, and reliable operations at our refinery is key to our financial performance and results of operations. Unplanned downtime of our refinery may result in lost margin opportunity, increased maintenance expense and a temporary increase in working capital investment and related inventory position. We seek to mitigate the financial impact of planned downtime, such as major turnaround maintenance, through a diligent planning process that takes into account the margin environment, the availability of resources to perform the needed maintenance, feedstock logistics and other factors.

We purchase most of our crude oil using a credit intermediation agreement. Our credit intermediation agreement is structured such that we take title, and the price of the crude oil is set, when it is metered and delivered at Broome Station, which is connected to, and located approximately 22 miles from, our refinery. Once delivered at Broome Station, the crude oil is delivered to our refinery through two of our wholly owned pipelines which begin at Broome Station and end at our refinery. The crude oil is delivered at Broome Station because Broome Station is located near our facility and is connected via pipeline to our facility. The terms of the credit intermediation agreement provide that we will obtain all of the crude oil for our refinery, other than the crude we obtain through our own gathering system, through J. Aron. Once we identify cargos of crude oil and pricing terms that meet our requirements, we notify J. Aron and J. Aron then provides credit, transportation and other logistical services to us for a fee. This agreement significantly reduces the investment that we are required to maintain in petroleum inventories relative to our competitors and reduces the time we are exposed to market fluctuations before the inventory is priced to a customer.

Because petroleum feedstocks and products are essentially commodities, we have no control over the changing market. Therefore, the lower target inventory we are able to maintain significantly reduces the impact of commodity price volatility on our petroleum product inventory position relative to other refiners. This target inventory position is generally not hedged. To the extent our inventory position deviates from the target level, we consider risk mitigation activities usually through the purchase or sale of futures contracts on the New York Mercantile Exchange, or NYMEX. Our hedging activities carry customary time, location and product grade basis risks generally associated with hedging activities. Because most of our titled inventory is valued under the FIFO costing method, price fluctuations on our target level of titled inventory have a major effect on our financial results unless the market value of our target inventory is increased above cost.

Nitrogen Fertilizer Business

In the nitrogen fertilizer business, earnings and cash flow from operations are primarily affected by the relationship between nitrogen fertilizer product prices and direct operating expenses. Unlike its competitors, the nitrogen fertilizer business uses minimal natural gas as feedstock and, as a result, is not directly impacted in terms of cost, by high or volatile swings in natural gas prices. Instead, our adjacent oil refinery supplies the majority of the coke feedstock needed by the nitrogen fertilizer business. The price at which nitrogen fertilizer products are ultimately sold depends on numerous factors, including the supply of, and the demand for, nitrogen fertilizer products which, in turn, depends on, among other factors, the price of natural gas, the cost and availability of fertilizer transportation infrastructure, changes in the world population, weather conditions, grain production levels, the availability of imports, and the extent of government intervention in agriculture markets. While net sales of the nitrogen fertilizer business could fluctuate significantly with movements in natural gas prices during periods when fertilizer markets are weak and sell at the floor price, high natural gas prices do not force the nitrogen fertilizer business to shut down its operations because it employs pet coke as a feedstock to produce ammonia and UAN.

Nitrogen fertilizer prices are also affected by other factors, such as local market conditions and the operating levels of competing facilities. Natural gas costs and the price of nitrogen fertilizer products have historically been subject to wide fluctuations. An expansion or upgrade of competitors facilities, price volatility, international political and economic developments and other factors are likely to continue to play an important role in nitrogen fertilizer industry economics. These factors can impact, among other things, the level of inventories in the market resulting in price volatility and a reduction in product margins. Moreover, the industry typically experiences seasonal fluctuations in demand for nitrogen fertilizer products. The demand for fertilizers is affected by the aggregate crop planting decisions and fertilizer application rate decisions of individual farmers. Individual farmers make planting decisions based largely on the prospective profitability of a harvest, while the specific varieties and amounts of fertilizer they apply depend on factors like crop prices, their current liquidity, soil conditions, weather patterns and the types of crops planted. For further details on the economics of fertilizer, see Industry Overview Nitrogen Fertilizer Industry.

Natural gas is the most significant raw material required in the production of most nitrogen fertilizers. North American natural gas prices have increased substantially and, since 1999, have become significantly more volatile. In 2005, North American natural gas prices reached unprecedented levels due to the impact hurricanes Katrina and Rita had on an already tight natural gas market. Recently, natural gas prices have moderated, returning to pre-hurricane levels or lower.

In order to assess the operating performance of the nitrogen fertilizer business, we calculate netbacks, also referred to as plant gate price, to determine our operating margin. Netbacks refer to the unit price of fertilizer, in dollars per ton, offered on a delivered basis, excluding shipment costs. Given the use of low cost pet coke, the nitrogen fertilizer business is not presently subjected to the high raw materials costs of competitors that use natural gas, the cost of which has been high in recent periods. Instead of experiencing high variability in the cost of raw materials, the nitrogen fertilizer business utilizes less than 1% of the natural gas relative to other natural gas-based fertilizer producers and we estimate that the nitrogen fertilizer business would continue to have a production cost advantage in comparison to U.S. Gulf Coast ammonia producers at natural gas prices as low as $2.50 per million Btu. The spot price for natural gas at Henry Hub on June 29, 2007 was $6.77 per million Btu.

Because the fertilizer plant has certain logistical advantages relative to end users of ammonia and UAN and so long as demand relative to production remains high, the nitrogen fertilizer business can afford to target end users in the U.S. farm belt where it incurs lower freight costs as compared to competitors. The farm belt refers to the states of Illinois, Indiana, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Texas and Wisconsin. The nitrogen fertilizer business does not incur any intermediate transfer, storage, barge freight or pipeline freight charges, giving us a distribution cost advantage over U.S. Gulf Coast importers, assuming freight rates and pipeline tariffs for U.S. Gulf Coast importers as recently in effect. Selling products to customers in close proximity to the fertilizer plant and keeping transportation costs low are keys to maintaining profitability.

The value of nitrogen fertilizer products is also an important consideration in understanding our results. The nitrogen fertilizer business currently upgrades approximately two-thirds of its ammonia production into UAN, a product that presently generates a greater value than ammonia. UAN production is a major contributor to our profitability.

The direct operating expense structure of the nitrogen fertilizer business is also important to its profitability. Using a pet coke gasification process, the nitrogen fertilizer business has significantly higher fixed costs than natural gas-based fertilizer plants. Major direct operating expenses include electrical energy, employee labor, maintenance, including contract labor, and outside services. These costs comprise the fixed costs associated with the fertilizer plant. Variable costs associated with the fertilizer plant have averaged approximately 1.1% of direct operating expenses over the last 24 months ending June 30, 2007. The average annual fixed costs over the last 24 months ending June 30, 2007 have approximated $62 million.

Consistent, safe, and reliable operations at the nitrogen fertilizer plant are critical to its financial performance and results of operations. Unplanned downtime of the nitrogen fertilizer plant may result in lost margin opportunity, increased maintenance expense and a temporary increase in working capital investment and related inventory position. The financial impact of planned downtime, such as major turnaround maintenance, is mitigated through a diligent planning process that takes into account margin environment, the availability of resources to perform the needed maintenance, feedstock logistics and other factors.

In connection with our transfer of the nitrogen fertilizer business to the Partnership, we will enter into a number of agreements with the Partnership that will govern the business relations between the parties. These include a coke supply agreement, under which we will sell pet coke to the nitrogen fertilizer business; a feedstock and shared services agreement, which will govern the provision of hydrogen, high-pressure steam, nitrogen, instrument air, oxygen and natural gas; a raw water and facilities sharing agreement, which will allocate raw water resources between the two businesses; a land transfer; an easement agreement; an environmental agreement; and a lease agreement pursuant to which we will lease office space and laboratory space to the Partnership.

The price paid by the nitrogen fertilizer business pursuant to the coke supply agreement will be based on the lesser of a coke price derived from the price received by the Partnership for UAN (subject to a UAN based price ceiling and floor) or a coke price index for pet coke. Historically, the cost of product sold (exclusive of depreciation and amortization) in the nitrogen business was based on a coke price of $15 per ton beginning with the Initial Acquisition. This is reflected in the segment data in our historical financial statements as a cost for the nitrogen fertilizer business and as revenue for the petroleum business. If the new terms of the coke supply agreement had been in place over the past three years, the new coke supply agreement would have resulted in an increase (or decrease) in cost of product sold (exclusive of depreciation and amortization) for the nitrogen fertilizer business (and an increase (or decrease) in revenue for the petroleum business) of $(2.9) million, $(1.5) million, $(0.7) million, $(3.5) million and $0.3 million for the 304 day period ending December 31, 2004, the 174 day period ended June 24, 2005, the 233 day period ended December 31, 2005, the year ended December 31, 2006 and the six months ended June 30, 2007. There would have been no impact to the consolidated financial statements as intercompany transactions are eliminated upon consolidation.

In addition, based on management s current estimates, the services agreement will result in an annual charge of approximately $11.5 million to the nitrogen fertilizer business for its portion of expenses which have been historically reflected in selling, general and administrative expenses (exclusive of depreciation and amortization) in our consolidated statement of operations. Historical nitrogen fertilizer segment operating income would decrease $4.1 million, increase $0.8 million, decrease $0.1 million, increase $7.4 million and decrease $0.7 million for the 304-day period ended December 31, 2004, the 174-day period ended June 23, 2005, the 233-day period ended December 31, 2005, the year ended December 31, 2006 and the six months ended June 30, 2007, respectively, assuming an annualized $11.5 million charge for the management services in lieu of the historical allocations of selling, general and administrative expenses. The petroleum segment s operating income would have had offsetting increases or decreases, as applicable, for these periods.

The total change to operating income for the nitrogen fertilizer segment with respect to both the coke supply agreement included in cost of product sold (exclusive of depreciation and amortization) and the services agreement included in selling, general and administrative (exclusive of depreciation and amortization) would be a decrease of $1.2 million, increase of $2.3 million, increase of $0.6 million, increase of $10.9 million and a decrease of $1.0 million for the 304-day period ended December 31, 2004, the 174-day period ended June 23, 2005, the 233-day period ended December 31, 2005, the year ended December 31, 2006 and the six months ended June 30, 2007, respectively.

The feedstock and shared services agreement, the raw water and facilities sharing agreement, the cross-easement agreement and the environmental agreement are not expected to have a significant impact on the financial results of the nitrogen fertilizer business. However, the requirement to supply hydrogen contained in the feedstock and shared services agreement could result in reduced fertilizer production due to a commitment to supply hydrogen to the refinery. The feedstock and shared services agreement requires the refinery to compensate the nitrogen fertilizer business for the value of production lost due to the hydrogen supply requirement. See The Nitrogen Fertilizer Limited Partnership Other Intercompany Agreements.

Results of Operations

The period to period comparisons of our results of operations have been prepared using the historical periods included in our financial statements. As discussed in Note 1 to our consolidated financial statements, effective March 3, 2004, Immediate Predecessor acquired the net assets of Original Predecessor in a business combination accounted for as a purchase, and effective June 24, 2005, Successor acquired the net assets of Immediate Predecessor in a business combination accounted for as a purchase. As a result of these acquisitions, the consolidated financial statements for the periods after the acquisitions are presented on a different cost basis than that for the periods before the acquisitions and, therefore, are not comparable. Accordingly, in this Results of Operations section, after comparing the six months ended June 30, 2007 with the six months ended June 30, 2006, we compare the year ended December 31, 2006 with the 174-day period ended June 23, 2005 and the 233-day period ended December 31, 2005. In addition, we compare the 174-day period ended June 23, 2005 and the 233-day period ended December 31, 2005 with the 62-day period ended March 2, 2004 and the 304-day period ended December 31, 2004.

Net sales consist principally of sales of refined fuel and nitrogen fertilizer products. For the petroleum business, net sales are mainly affected by crude oil and refined product prices, changes to the input mix and volume changes caused by operations. Product mix refers to the percentage of production represented by higher value light products, such as gasoline, rather than lower value finished products, such as pet coke. In the nitrogen fertilizer business, net sales are primarily impacted by manufactured tons and nitrogen fertilizer prices.

Industry-wide petroleum results are driven and measured by the relationship, or margin, between refined products and the prices for crude oil referred to as crack spreads. See Factors Affecting Results. We discuss our results of petroleum operations in the context of per barrel consumed crack spreads and the relationship between net sales and cost of product sold.

Our consolidated results of operations include certain other unallocated corporate activities and the elimination of intercompany transactions and therefore are not a sum of only the operating results of the petroleum and nitrogen fertilizer businesses.

In order to effectively review and assess our historical financial information below, we have also included supplemental operating measures and industry measures which we believe are material to understanding our business. For the years ended December 31, 2004 and 2005 we have provided this supplemental information on a combined basis in order to provide a comparative basis for similar periods of time. As discussed above, due to the various acquisitions that occurred, there were multiple financial statement periods of less than 12 months. We believe that the most meaningful way to present this supplemental data for the various periods is to compare the sum of the combined operating results for the 2004 and 2005 calendar years with prior fiscal years, and to compare the sum of the combined operating results for the year ended December 31, 2005 with the year ended December 31, 2006.

Accordingly, for purposes of displaying supplemental operating data for the year ended December 31, 2005, we have combined the 174-day period ended June 23, 2005 and the 233-day period ended December 31, 2005 to provide a comparative year ended December 31, 2005 to the year ended December 31, 2006. Additionally, the 62-day period ended March 2, 2004 and the 304-day period ended December 31, 2004 have been combined to provide a comparative twelve month period ended December 31, 2004 to a combined twelve month period ended December 31, 2005 comprised of the 174-day period ended June 23, 2005 and the 233-day period ended December 31, 2005.

We changed our corporate selling, general and administrative allocation method to the operating segments in 2007. The effect of the change on operating income for the 304-day period ended

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December 31, 2004, the 174-day period ended June 23, 2005, the 233-day period ended December 31, 2005, the six month period ended June 30, 2006 and the year ended December 31, 2006 would have been a decrease of $0.4 million, $1.0 million, $1.4 million, $2.0 million and $6.0 million, respectively, to the petroleum segment, an increase of $0.4 million, $1.2 million, $1.4 million, $2.0 million and $6.0 million, respectively, to the nitrogen fertilizer segment and a decrease of $0.0 million, $0.2 million, $0.0 million, $0.0 million and $0.0 million, respectively, to the other segment.

	Original Predecessor		Immediate Predecessor		Successor			
onsolidated Financial Results	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Six Months Ended June 30, 2006	2007
			(in millions)				(unaudited)	
t sales	$ 1,262.2	$ 261.1	$ 1,479.9	$ 980.7	$ 1,454.3	$ 3,037.6	$ 1,550.6	$ 1,233.
st of product sold (exclusive of preciation and amortization)	1,061.9	221.4	1,244.2	768.0	1,168.1	2,443.4	1,203.4	873.
ect operating expenses clusive of depreciation and ortization)	133.1	23.4	117.0	80.9	85.3	199.0	87.8	174.
ling, general and ministrative expense (exclusive depreciation and amortization)	23.6	4.7	16.3	18.4	18.4	62.6	20.5	28.
sts associated with flood(1)								2.
preciation and amortization(2)	3.3	0.4	2.4	1.1	24.0	51.0	24.0	32.
pairment, (losses) in joint tures, and other charges(3)	(10.9)							
erating income	$ 29.4	$ 11.2	$ 100.0	$ 112.3	$ 158.5	$ 281.6	$ 214.9	$ 123.
t income (loss)(4)	27.9	11.2	49.7	52.4	(119.2)	191.6	41.8	(54.
t income (loss) adjusted for realized gain or loss from Cash w Swap(5)	27.9	11.2	49.7	52.4	23.6	115.4	101.0	59.

(1) Represents the write-off of approximately $2.1 million of property, inventories and catalyst that were destroyed by the flood that occurred on June 30, 2007. See Flood and Crude Oil Discharge.

(2) Depreciation and amortization is comprised of the following components as excluded from cost of products sold, direct operating expense and selling, general and administrative expense:

Original Predecessor		Immediate Predecessor		Successor		
Year	62 Days	304 Days	174 Days	233 Days	Year	Six Months

	Ended December 31, 2003	Ended March 2, 2004	Ended December 31, 2004	Ended June 23, 2005	Ended December 31, 2005	Ended December 31, 2006	Ended June 30, 2006	2007
			(in millions)				(unaudited)	
Depreciation and amortization included in cost of product sold			0.2	0.1	1.1	2.2	1.0	1.2
Depreciation and amortization included in direct operating expenses	3.3	0.4	2.0	0.9	22.7	47.7	22.8	30.6
Depreciation and amortization included in selling, general and administrative expense			0.2	0.1	0.2	1.1	0.2	0.4
Total depreciation and amortization	3.3	0.4	2.4	1.1	24.0	51.0	24.0	32.2

(3) During the year ended December 31, 2003, we recorded an additional charge of $9.6 million related to the asset impairment of the refinery and nitrogen fertilizer plant based on the expected sales price of the assets in the Initial Acquisition. In addition, we recorded a charge of $1.3 million for the rejection of existing contracts while operating under Chapter 11 of the U.S. Bankruptcy Code.

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(4) The following are certain charges and costs incurred in each of the relevant periods that are meaningful to understanding our net income and in evaluating our performance due to their unusual or infrequent nature:

	Original Predecessor		**Immediate Predecessor**		**Successor**			
	Year Ended December 31, 2003	**62 Days Ended March 2, 2004**	**304 Days Ended December 31, 2004**	**174 Days Ended June 23, 2005**	**233 Days Ended December 31, 2005**	**Year Ended December 31, 2006**	**Six Months Ended June 30, 2006**	**Six Months Ended June 30, 2007**
			(in millions)				**(unaudited)**	
Impairment of property, plant and equipment(a)	$ 9.6	$	$	$	$	$	$	$
Loss of extinguishment of debt(b)			7.2	8.1		23.4		
Inventory fair market value adjustment(c)			3.0		16.6			
Funded letter of credit expense & interest rate swap not included in interest expense(d)					2.3		0.6	0.2
Major scheduled turnaround expense(e)			1.8			6.6	0.3	76.8
Loss on termination of swap(f)					25.0			
Unrealized (gain) loss from Cash Flow Swap					235.9	(126.8)	98.2	188.5

(a) During the year ended December 31, 2003, we recorded an additional charge of $9.6 million related to the asset impairment of the refinery and nitrogen fertilizer plant based on the expected sales price of the assets in the Initial Acquisition.

(b) Represents the write-off of $7.2 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on May 10, 2004, the write-off of $8.1 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on June 23, 2005 and the write-off of $23.4 million in connection with the refinancing of our senior secured credit facility on December 28, 2006.

(c) Consists of the additional cost of product sold expense due to the step up to estimated fair value of certain inventories on hand at March 3, 2004 and June 24, 2005, as a result of the allocation of the purchase price of the Initial Acquisition and the Subsequent Acquisition to inventory.

(d) Consists of fees which are expensed to selling, general and administrative expense in connection with the funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap. We consider these fees to be equivalent to interest expense and the fees are treated as such in the calculation of EBITDA in the Credit Facility.

(e) Represents expenses associated with a major scheduled turnaround at the nitrogen fertilizer plant and our refinery.

(f) Represents the expense associated with the expiration of the crude oil, heating oil and gasoline option agreements entered into by Coffeyville Acquisition LLC in May 2005.

(5) Net income adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for the derivative transaction that was executed in conjunction with the Subsequent Acquisition. On June 16, 2005, Coffeyville Acquisition LLC entered into the Cash Flow Swap with J. Aron, a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The Cash Flow Swap was subsequently assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. The derivative took the form of three NYMEX swap agreements whereby if crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. With crude oil capacity expected to reach 115,000 bpd by the end of 2007, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of the Credit Facility and upon meeting specific requirements related to an initial public offering, our leverage ratio and our credit ratings, and assuming our other credit facilities are terminated or amended to allow such actions, we may reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010. See Description of Our Indebtedness and the Cash Flow Swap.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current GAAP. As a result, our periodic statements of operations reflect material amounts of unrealized gains and losses based on the increases or decreases in market value of the unsettled position under the swap agreements which is accounted for as a liability on our balance sheet. As the crack spreads increase we are required to record an increase in this liability account with a corresponding expense entry to be made to our statement of operations. Conversely, as crack spreads decline, we are required to record a decrease in the swap related liability and post a corresponding income entry to our statement of operations. Because of this inverse relationship between the economic outlook for our underlying business (as represented by crack spread levels) and the income impact of the unrecognized gains and losses, and given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income adjusted for gain or loss from

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Cash Flow Swap as a key indicator of our business performance. In managing our business and assessing its growth and profitability from a strategic and financial planning perspective, management and our Board of Directors considers our U.S. GAAP net income results as well as Net income adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income adjusted for unrealized gain or loss from Cash Flow Swap enhances the understanding of our results of operations by highlighting income attributable to our ongoing operating performance exclusive of charges and income resulting from mark to market adjustments that are not necessarily indicative of the performance of our underlying business and our industry. The adjustment has been made for the unrealized loss from Cash Flow Swap net of its related tax benefit.

Net income adjusted for unrealized gain or loss from Cash Flow Swap is not a recognized term under GAAP and should not be substituted for net income as a measure of our financial performance or liquidity but instead should be utilized as a supplemental measure of performance in evaluating our business. Because Net income adjusted for unrealized gain or loss from Cash Flow Swap excludes mark to market adjustments, the measure does not reflect the fair market value of our cash flow swap in our net income. As a result, the measure does not include potential cash payments that may be required to be made on the Cash Flow Swap in the future. Also, our presentation of this non-GAAP measure may not be comparable to similarly titled measures of other companies.

The following is a reconciliation of Net income adjusted for unrealized gain or loss from Cash Flow Swap to Net income:

	Original Predecessor		Immediate Predecessor		Successor			
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007
			(in millions)				(unaudited)	
Net Income (loss) adjusted for unrealized gain or loss from Cash Flow Swap	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ 23.6	$ 115.4	$ 101.0	$ 59.0
Plus: Unrealized gain or (loss) from Cash Flow Swap, net of taxes					(142.8)	76.2	(59.2)	(113.3)
Net income (loss)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ (119.2)	$ 191.6	$ 41.8	$ (54.3)

Petroleum Business Results of Operations

Refining margin is a measurement calculated as the difference between net sales and cost of products sold (exclusive of depreciation and amortization). Refining margin is a non-GAAP measure that we believe is important to investors in evaluating our refinery s performance as a general indication of the amount above our cost of products that we are able to sell refined products. Each of the components used in this calculation (net sales and cost of products sold exclusive of depreciation and amortization) can be taken directly from our statement of operations. Our calculation of refining margin may differ from similar calculations of other companies in our industry, thereby limiting its

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usefulness as a comparative measure. The following table shows selected information about our petroleum business including refining margin:

	Original Predecessor		Immediate Predecessor		Successor			
	Year Ended	62 Days Ended	304 Days Ended	174 Days Ended	233 Days Ended	Year Ended	Six Months Ended	
	December 31, 2003	March 2, 2004	December 31, 2004	June 23, 2005	December 31, 2005	December 31, 2006	June 30, 2006 (unaudited)	June 30, 2007 (unaudited)
	(in millions, except as otherwise indicated)							
Petroleum Business:								
Net sales	$ 1,161.3	$ 241.6	$ 1,390.8	$ 903.8	$ 1,363.4	$ 2,880.4	$ 1,457.7	$ 1,161.4
Cost of product sold (exclusive of depreciation and amortization)	1,040.0	217.4	1,228.1	761.7	1,156.2	2,422.7	1,190.5	869.1
Direct operating expenses (exclusive of depreciation and amortization)	80.1	14.9	73.2	52.6	56.2	135.3	59.1	141.1
Costs associated with flood								2.0
Depreciation and amortization	2.1	0.3	1.5	0.8	15.6	33.0	15.6	23.1
Gross profit (loss)	$ 39.1	$ 9.0	$ 88.0	$ 88.7	$ 135.4	$ 289.4	$ 192.5	$ 126.1
Plus direct operating expenses (exclusive of depreciation and amortization)	80.1	14.9	73.2	52.6	56.2	135.3	59.1	141.1
Plus costs associated with flood								2.0
Plus depreciation and amortization	2.1	0.3	1.5	0.8	15.6	33.0	15.6	23.1
Refining margin	$ 121.3	$ 24.2	$ 162.7	$ 142.1	$ 207.2	$ 457.7	$ 267.2	$ 292.3
Refining margin per refinery throughput barrel	$ 3.89	$ 4.23	$ 5.92	$ 9.28	$ 11.55	$ 13.27	$ 15.69	22.71
Gross profit (loss) per refinery throughput barrel	$ 1.25	$ 1.57	$ 3.20	$ 5.79	$ 7.55	$ 8.39	$ 11.30	$ 9.80
Direct operating expenses (exclusive of depreciation and	$ 2.57	$ 2.60	$ 2.66	$ 3.44	$ 3.13	$ 3.92	$ 3.47	$ 10.96

amortization) per refinery throughput barrel								
Operating income (loss)	21.5	7.7	77.1	76.7	123.0	245.6	178.0	102.9

Market Indicators	Original Predecessor 2003	Original Predecessor and Immediate Predecessor Combined 2004	Immediate Predecessor and Successor Combined 2005	Successor 2006	Successor Six Months Ended June 30, 2006	2007
		Year Ended December 31, (dollars per barrel)				
West Texas Intermediate (WTI) crude oil	$ 30.99	$ 41.47	$ 56.70	$ 66.25	$ 67.13	$ 61.67
NYMEX 2-1-1 Crack Spread	5.53	7.43	11.62	10.84	12.02	17.13
Crude Oil Differentials:						
WTI less WTS (sour)	2.67	3.96	4.73	5.36	5.87	4.42
WTI less Maya (heavy sour)	6.78	11.40	15.67	14.99	15.88	11.20
WTI less Dated Brent (foreign)	2.16	3.20	2.18	1.13	1.47	(1.54)
PADD II Group 3 versus NYMEX Basis:						
Gasoline	0.62	(0.52)	(0.53)	1.52	0.74	2.59
Heating Oil	1.11	1.24	3.20	7.42	5.63	9.29

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Company Operating Statistics	Original Predecessor 2003	Original Predecessor and Immediate Predecessor Combined 2004	Immediate Predecessor and Successor Combined 2005	Successor 2006	Successor Six Months Ended June 30, 2006	2007
	Year Ended December 31, (dollars per barrel)					
Per barrel profit, margin and expense of crude oil throughput:						
Refining margin	$ 3.89	$ 5.62	$ 10.50	$ 13.27	$ 15.69	$ 22.71
Gross profit	$ 1.25	$ 2.92	$ 6.74	$ 8.39	$ 11.30	$ 9.80
Direct operating expenses (exclusive of depreciation and amortization)	2.57	2.65	3.27	3.92	3.47	10.96
Per gallon sales price:						
Gasoline	0.91	1.19	1.61	1.88	1.94	2.09
Distillate	0.84	1.15	1.71	1.99	1.97	2.03

pany Data	Original Predecessor 2003 Barrels Per Day	%	Original Predecessor and Immediate Predecessor Combined 2004 Barrels Per Day	%	Immediate Predecessor and Successor Combined 2005 Barrels Per Day	%	Successor 2006 Barrels Per Day	%	Successor Six Months Ended June 30, 2006 Barrels Per Day	%	Barrel Per Da
	Year Ended December 31,										
	48,230	50.4	48,420	47.1	45,275	43.8	48,248	44.7	48,250	45.1	31,97
	34,363	35.9	38,104	37.1	39,997	38.7	42,175	39.0	42,275	39.5	32,59
	13,108	13.7	16,301	15.9	18,090	17.5	17,608	16.3	16,390	15.3	13,53
ction	95,701	100.0	102,825	100.0	103,362	100.0	108,031	100.0	106,915	100.0	78,09
	85,501	93.4	90,787	92.8	91,097	92.6	94,524	92.1	94,083	92.8	71,09
s	6,085	6.6	7,023	7.2	7,246	7.4	8,067	7.9	7,276	7.2	3,76
ks	91,586	100.0	97,810	100.0	98,343	100.0	102,591	100.0	101,359	100.0	74,86

	Original Predecessor	Immediate

Original Predecessor		and Immediate Predecessor Combined		Predecessor and Successor Combined		Successor		Success	
		Year Ended December 31,						Six Months End	
2003		2004		2005		2006		2006	
Total Barrels	%	Total Barrels	%	Total Barrels	%	Total Barrels	%	Total Barrels	%
8,187,215	58.3	15,232,022	45.8	13,958,567	42.0	17,481,803	50.7	7,497,863	44.0
2,311,203	39.4	17,995,949	54.2	19,291,951	58.0	16,695,173	48.4	9,531,125	56.0
709,300	2.3					324,312	0.9		
31,207,718	100.0	33,227,971	100.0	33,250,518	100.0	34,501,288	100.0	17,028,988	100.0

Six Months Ended June 30, 2007 Compared to the Six Months Ended June 30, 2006.

Net Sales. Petroleum net sales were $1,161.4 million for the six months ended June 30, 2007 compared to $1,457.7 million for the six months ended June 30, 2006. The decrease of $296.3 million from the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was primarily the result of significantly lower sales volumes ($366.6 million), partially offset by higher product prices ($70.3 million). Overall sales volumes of refined fuels for the six months ended June 30, 2007 decreased 25% as compared to the six months ended June 30, 2006. The decreased sales volume primarily resulted from a significant reduction in refined fuel production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007. Our average sales price per gallon for the six months ended June 30, 2007 for gasoline of $2.09 and distillate of $2.03 increased by 8.0% and 3.0%, respectively, as compared to the six months ended June 30, 2006.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Definitions of the terms feedstocks and blendstocks are contained in the section of this prospectus entitled Glossary of Selected Terms. Petroleum cost of product sold exclusive of depreciation and amortization was $869.1 million for the six months ended June 30, 2007 compared to $1,190.5 million for the six months ended June 30, 2006. The decrease of $321.4 million from the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was primarily the result of a significant reduction in crude throughput due to the refinery turnaround which began in February 2007 and was completed in April 2007. In addition to the impact of the turnaround, lower crude oil prices, reduced sales volumes and the impact of FIFO accounting also impacted cost of product sold during the comparable periods. Our average cost per barrel of crude oil for the six months ended June 30, 2007 was $57.14, compared to $61.74 for the comparable period of 2006, a decrease of 8%. Sales volume of refined fuels decreased 25% for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 principally due to the turnaround. In addition, under our FIFO accounting method, changes in crude oil prices can cause fluctuations in the inventory valuation of our crude oil, work in process and finished goods, thereby resulting in FIFO inventory gains when crude oil prices increase and FIFO inventory losses when crude oil prices decrease. For the six months ended June 30, 2007, we reported FIFO inventory gains of $18.7 million compared to FIFO inventory gains of $20.0 million for the comparable period of 2006.

Refining margin per barrel of crude throughput increased from $15.69 for the six months ended June 30, 2006 to $22.71 for the six months ended June 30, 2007 primarily due to the 43% increase ($5.11 per barrel) in the average NYMEX 2-1-1 crack spread over the comparable periods and positive regional differences between gasoline and distillate prices in our primary marketing region (the Coffeyville supply area) and those of the NYMEX. The average gasoline basis for the six months ended June 30, 2007 increased by $1.85 per barrel to $2.59 per barrel compared to $0.74 per barrel in the comparable period of 2006. The average distillate basis for the six months ended June 30, 2007 increased by $3.66 per barrel to $9.29 per barrel compared to $5.63 per barrel in the comparable period of 2006. The positive effect of the increased NYMEX 2-1-1 crack spreads and refined fuels basis over the comparable periods was partially offset by reductions in the crude oil differentials over the comparable periods. Decreased discounts for sour crude oils evidenced by the $1.45 per barrel, or 25%, decrease in the spread between the WTI price, which is a market indicator for the price of light sweet crude, and the WTS price, which is an indicator for the price of sour crude, negatively impacted refining margin for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006.

Costs Associated with Flood. Petroleum costs associated with the flood for the six months ended June 30, 2007 approximated $2.0 million as compared to none for the six months ended June 30, 2006. The costs associated with the flood for the six months ended June 30, 2007 include primarily write-offs of property and inventories that are uninsured due to our insurance deductibles.

Depreciation and Amortization. Petroleum depreciation and amortization was $23.1 million for the six months ended June 30, 2007 as compared to $15.6 million for the six months ended June 30, 2006. The increase of $7.5 million for the six months ended June 30, 2007 compared to the

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six months ended June 30, 2006 was primarily the result of the completion of several large capital projects in late 2006 and during the six months ending June 30, 2007.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance (turnaround), labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $141.1 million for the six months ended June 30, 2007 compared to direct operating expenses of $59.1 million for the six months ended June 30, 2006. The increase of $82.0 million for the six months ended June 30, 2007 compared to the six months ended June 30, 2006 was the result of increases in expenses associated with repairs and maintenance associated with the refinery turnaround ($74.2 million), direct labor ($4.5 million), taxes ($3.5 million), outside services ($1.3 million) and insurance ($1.3 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with energy and utilities ($3.3 million) and environmental compliance ($1.8 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for the six months ended June 30, 2007 increased to $10.96 per barrel as compared to $3.47 per barrel for the six months ended June 30, 2006 principally due to refinery turnaround expenses and the related downtime associated with the turnaround and its impact on overall production volume.

Operating Income. Petroleum operating income was $102.9 million for the six months ended June 30, 2007 as compared to operating income of $178.0 million for the six months ended June 30, 2006. This decrease of $75.1 million from the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was primarily the result of the refinery turnaround which began in February 2007 and was completed in April 2007. The turnaround negatively impacted daily refinery crude throughput and refined fuels production. In addition, direct operating expenses increased substantially during the six months ended June 30, 2007 primarily due to repairs and maintenance associated with the refinery turnaround ($74.2 million), direct labor ($4.5 million), taxes ($3.5 million), outside services ($1.3 million) and insurance ($1.3 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with energy and utilities ($3.3 million) and environmental compliance ($1.8 million).

Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005.

Net Sales. Petroleum net sales were $2,880.4 million for the year ended December 31, 2006 compared to $903.8 million for the 174 days ended June 23, 2005 and $1,363.4 million for the 233 days ended December 31, 2005. The increase of $613.2 million from the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 resulted from significantly higher product prices ($384.1 million) and increased sales volumes ($229.1 million) over the comparable periods. Our average sales price per gallon for the year ended December 31, 2006 for gasoline of $1.88 and distillate of $1.99 increased by 17% and 16%, respectively, as compared to the year ended December 31, 2005. Overall sales volumes of refined fuels for the year ended December 31, 2006 increased 9% as compared to the year ended December 31, 2005. The increased sales volume primarily resulted from higher production levels of refined fuels during the year ended December 31, 2006 as compared to the same period in 2005 because of our increased focus on process unit maximization and lower production levels in 2005 due to a scheduled reformer regeneration and minor maintenance in the coker unit and one of our crude units. Definitions of the terms coker unit and crude unit are contained in the section of this prospectus entitled Glossary of Selected Terms.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Petroleum cost of product sold exclusive of depreciation and amortization was $2,422.7 million for the year ended December 31, 2006 compared to $761.7 million

for the 174 days ended June 23, 2005 and $1,156.2 million for the 233 days ended December 31, 2005. The increase of $504.8 million from the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was primarily the result of higher crude oil prices, increased sales volumes and the impact of FIFO accounting. Our average cost per barrel of crude oil for the year ended December 31, 2006 was $61.71, compared to $53.42 for the comparable period of 2005, an increase of 16%. Crude oil prices increased on average by 17% during the year ended December 31, 2006 as compared to the comparable period of 2005 due to the residual impact of Hurricanes Katrina and Rita on the refining sector, geopolitical concerns and strong demand for refined products. Sales volume of refined fuels increased 9% for the year ended December 31, 2006 as compared to the year ended December 31, 2005. In addition, under our FIFO accounting method, changes in crude oil prices can cause significant fluctuations in the inventory valuation of our crude oil, work in process and finished goods, thereby resulting in FIFO inventory gains when crude oil prices increase and FIFO inventory losses when crude oil prices decrease. For the year ended December 31, 2006, we reported FIFO inventory loss of $7.6 million compared to FIFO inventory gains of $18.6 million for the comparable period of 2005.

Refining margin per barrel of crude throughput increased from $10.50 for the year ended December 31, 2005 to $13.27 for the year ended December 31, 2006, due to increased discount for sour crude oils demonstrated by the $0.63, or 13%, increase in the spread between the WTI price, which is a market indicator for the price of light sweet crude, and the WTS price, which is an indicator for the price of sour crude, for the year ended December 31, 2006 as compared to the year ended December 31, 2005. In addition, positive regional differences between refined fuel prices in our primary marketing region (the Coffeyville supply area) and those of the NYMEX, known as basis, significantly contributed to the increase in our consumed crack spread in the year ended December 31, 2006 as compared to the year ended December 31, 2005. The average distillate basis for the year ended December 31, 2006 increased by $4.22 per barrel to $7.42 per barrel compared to $3.20 per barrel in the comparable period of 2005. The average gasoline basis for the year ended December 31, 2006 increased by $2.05 per barrel to $1.52 per barrel in comparison to a negative basis of $0.53 per barrel in the comparable period of 2005.

Depreciation and Amortization. Petroleum depreciation and amortization was $33.0 million for the year ended December 31, 2006 as compared $0.8 million for the 174 days ended June 23, 2005 and $15.6 million for the 233 days ended December 31, 2005. The increase of $16.6 million for the year ended December 31, 2006 compared to the combined periods for the year ended December 31, 2005 was primarily the result of the step-up in our property, plant and equipment for the Subsequent Acquisition. See Factors Affecting Comparability.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance, labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $135.3 million for the year ended December 31, 2006 compared to direct operating expenses of $52.6 million for the 174 days ended June 23, 2005 and $56.2 million for the 233 days ended December 31, 2005. The increase of $26.5 million for the year ended December 31, 2006 compared to the combined periods for the year ended December 31, 2005 was the result of increases in expenses associated with direct labor ($3.3 million), rent and lease ($2.3 million), environmental compliance ($1.9 million), operating materials ($1.2 million), repairs and maintenance ($7.7 million), major scheduled turnaround ($4.0 million), chemicals ($3.0 million), insurance $(1.3 million) and outside services ($1.4 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for the year ended December 31, 2006 increased to $3.92 per barrel as compared to $3.27 per barrel for the year ended December 31, 2005.

Operating Income. Petroleum operating income was $245.6 million for the year ended December 31, 2006 as compared to $76.7 million for the 174 days ended June 23, 2005 and $123.0 million for the 233 days ended December 31, 2005 This increase of $45.9 million from the

year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 primarily resulted from higher refining margins due to improved crude differentials and strong gasoline and distillate basis during the comparable periods. The increase in operating income was somewhat offset by expenses associated with direct labor ($3.3 million), rent and lease ($2.3 million), environmental compliance ($1.9 million), operating materials ($1.2 million), repairs and maintenance ($7.7 million), major scheduled turnaround ($4.0 million), chemicals ($3.0 million), insurance ($1.3 million), outside services ($1.4 million) and depreciation and amortization ($16.6 million).

233 Days Ended December 31, 2005 and the 174 Days Ended June 23, 2005 Compared to the 304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004.

Net Sales. Petroleum net sales were $1,363.4 million for the 233 days ended December 31, 2005 and $903.8 million for the 174 days ended June 23, 2005 compared to $1,390.8 million for the 304 days ended December 31, 2004 and $241.6 million for the 62 days ended March 2, 2004. The increase of $634.8 million for the combined periods for the year ended December 31, 2005 as compared to the combined periods for the year ended December 31, 2004 was primarily attributable to increases in product prices ($688.3 million) offset by reduced sales volumes ($53.5 million) as compared to 2004. As compared to 2004, sales prices of gasoline and distillates increased for the combined 2005 period by 35% and 49%, respectively. Sales prices increased primarily as a result of increased crude oil prices and improvements in the gasoline and distillate crack spreads. The increase in average refined product prices was partially offset by a 3% decrease in refined fuels sales volume due to a 1% reduction in refined fuels production volumes in 2005 as compared to 2004. Refined fuels production was negatively impacted in 2005 due to a scheduled reformer regeneration and an outage in the fluidized catalytic cracking unit at our Coffeyville refinery.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Petroleum cost of product sold exclusive of depreciation and amortization was $1,156.2 million for the 233 days ended December 31, 2005 and $761.7 million for the 174 days ended June 23, 2005 compared to $1,228.1 million for the 304 days ended December 31, 2004 and $217.4 million for the 62 days ended March 2, 2004. The increase of $472.5 million for the combined periods for the year ended December 31, 2005 as compared to the combined periods in the year ended December 31, 2004 was primarily the result of higher crude oil prices partially offset by lower sales volumes and the impact of FIFO accounting. Our average cost per barrel of crude oil for the year ended December 31, 2005 was $53.42, compared to $40.23 for the same period in 2004, an increase of 33%. Crude oil prices increased significantly in 2005 as compared to 2004 due to the impact of Hurricanes Katrina and Rita, geopolitical concerns and strong demand for refined products in 2005. Sales volume decreased 3.0% for the year ended December 31, 2005 as compared to 2004. In addition, under our FIFO accounting method, changes in crude oil prices can cause significant fluctuations in the inventory valuation of our crude oil, work in process and finished goods, thereby resulting in FIFO inventory gains when crude oil prices increase and FIFO inventory losses when crude oil prices decrease. For the year ended December 31, 2005, we reported FIFO inventory gains of $18.6 million compared to FIFO inventory gains of $9.2 million for the comparable period of 2004.

Refining margin per barrel of crude throughput increased from $5.62 for the year ended December 31, 2004 to $10.50 for the year ended December 31, 2005, due to historically high differentials between refined fuel prices and crude oil prices as exemplified in the average NYMEX crack spread of $11.62 per barrel for the year ended December 31, 2005 as compared to $7.43 per barrel for 2004. Increased discount for heavy crude oils demonstrated by the $4.27, or 37%, increase in the spread between the WTI price, which is a market indicator for the price of light sweet crude, and the Maya price, which is an indicator for the price of heavy crude, in the year ended December 31, 2005 compared to the same period in 2004 also contributed to the increased refining margin over the

comparable period. In addition to the widening of the NYMEX crack spread and the increase in crude differentials, positive regional differences between refined fuel prices in our primary marketing region (PADD II, Group 3) and those of the NYMEX, known as basis, also contributed to the dramatic increase in our consumed crack spread in the year ended December 31, 2005 as compared to 2004. The average distillate basis for the year ended December 31, 2005 increased $1.96 per barrel to $3.20 per barrel as compared to $1.24 per barrel for the comparable period of 2004. The average gasoline basis for the year ended December 31, 2005 as compared to the year ended December 31, 2004 was essentially flat at a negative basis of $0.53 per barrel as compared to a negative basis of $0.52 per barrel in 2004.

Depreciation and Amortization. Petroleum depreciation and amortization was $15.6 million for the 233 days ended December 31, 2005 and $0.8 million for the 174 days ended June 23, 2005 compared to $1.5 million for the 304 days ended December 31, 2004 and $0.3 million for the 62 days ended March 2, 2004. The increase of $14.6 million for the combined period ended December 31, 2005 as compared to the combined period ended December 31, 2004 was primarily the result of the step-up in our property, plant and equipment for the Subsequent Acquisition. See Factors Affecting Comparability.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance, labor and environmental compliance costs. Petroleum direct operating expenses were $56.2 million for the 233 days ended December 31, 2005 and $52.6 million for the 174 days ended June 23, 2005 compared to $73.2 million for the 304 days ended December 31, 2004 and $14.9 million for the 62 days ended March 2, 2004. The increase of $20.6 million for the combined period ended December 31, 2005 as compared to direct operating expenses of $88.2 million for the combined period in 2004 was the result of increases in expenses associated with labor and incentive bonuses ($2.2 million), environmental compliance ($2.5 million), repairs and maintenance ($9.1 million), chemicals ($1.9 million), energy and utilities ($1.9 million) and outside services ($1.9 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for 2005 increased to $3.27 per barrel as compared to $2.65 per barrel for 2004.

Operating Income. Petroleum operating income was $123.0 million for the 233 days ended December 31, 2005 and $76.7 million for the 174 days ended June 23, 2005 compared to $77.1 million for the 304 days ended December 31, 2004 and $7.7 million for the 62 days ended March 2, 2004. The increase of $114.9 million for the combined period ended December 31, 2005 as compared to the combined period ended December 31, 2004 primarily resulted from higher refining margin due to favorable market conditions in the domestic refining industry somewhat offset by a 3% decrease in sales volumes and increases in expenses associated with labor and incentive bonuses ($2.2 million), environmental compliance ($2.5 million), repairs and maintenance ($9.1 million), chemicals ($1.9 million), energy and utilities ($1.9 million), outside services ($1.9 million) and depreciation and amortization ($14.6 million).

304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004 Compared to Year Ended December 31, 2003.

Net Sales. Petroleum net sales were $1,390.8 million for the 304 days ended December 31, 2004 and $241.6 million for the 62 days ended March 2, 2004 compared to $1,161.3 million in the year ended December 31, 2003. This revenue increase for the combined periods ended December 31, 2004 compared to the year ended December 31, 2003 was attributable to increased production volumes ($83.2 million) and higher product prices ($387.9 million), which reacted favorably to the increase in global crude oil prices over the period. In 2004, crude oil throughput increased by an average of 5,286 bpd, or 6%, as compared to 2003. The higher crude throughput experienced in 2004 as compared to 2003 was directly attributable to Farmland s inability, because of its impending reorganization, to purchase optimum crude oil blends necessary to operate the refinery at 2004 levels

in 2003. During 2004, our petroleum business experienced increases in gasoline and distillate prices of 31% and 37%, respectively, as compared to the same period in 2003.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Petroleum cost of product sold exclusive of depreciation and amortization was $1,228.1 million for the 304 days ended December 31, 2004 and $217.4 million for the 62 days ended March 2, 2004 compared to $1,040.0 million in the year ended December 31, 2003. This increase for the combined periods of the year ended December 31, 2004 as compared to the year ended December 31, 2003 was attributable to strong differentials between refined products prices and crude oil prices as exemplified in the average NYMEX crack spread of $7.43 per barrel for the year ended December 31, 2004 as compared to $5.53 per barrel in the comparable period of 2003. Increased discount for heavy crude oils demonstrated by the $4.62, or 68%, increase in the spread between the WTI price, which is a market indicator for the price of light sweet crude, and the Maya price, which is a market indicator for the price of heavy crude, in the year ended December 31, 2004 as compared to the same period in 2003 also contributed to the increase in refining margin over the comparable periods. Diluting the positive impact of the widening of the NYMEX crack spread and the increased crude differentials was the negative impact of gasoline prices in our primary marketing area (PADD II, Group 3) in comparison to gasoline prices on the NYMEX, known as basis. The average gasoline basis for the year ended December 31, 2004 decreased $1.14 per barrel to a negative basis of $0.52 per barrel as compared to $0.62 per barrel for 2003. The average distillate basis for the year ended December 31, 2004 was $1.24 per barrel compared to $1.11 per barrel in 2003. Additionally, our refining margin for the year ended December 31, 2004 improved as a result of the termination of a single customer product marketing agreement in November 2003. During 2003 Farmland was party to a marketing agreement that required it to sell all refined products to a single customer at a fixed differential to an index price. Subsequent to the conclusion of the contract, we have expanded our customer base and increased the realized differential to that index.

Depreciation and Amortization. Petroleum depreciation and amortization was $1.5 million for the 304 days ended December 31, 2004 and $0.3 million for the 62 days ended March 2, 2004 compared to $2.1 million for the year ended December 31, 2003. The decrease of $0.3 million for the combined periods of the year ended December 31, 2004 as compared to the year ended December 31, 2003 was primarily the result of the petroleum assets useful lives being reset to longer periods in the Initial Acquisition as compared to the prior period based on management s assessment of the condition of the petroleum assets acquired, offset by the impact of the step-up in value of the acquired assets in the Initial Acquisition.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance, labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $73.2 million for the 304 days ended December 31, 2004 and $14.9 million for the 62 days ended March 2, 2004 as compared to $80.1 million in the corresponding period of 2003. The primary reason for the increase for the combined periods for the year ended December 31, 2004 relative to the year ended December 31, 2003 were due to expenses associated with environmental compliance ($1.1 million), repairs and maintenance ($2.8 million), chemicals ($2.3 million) and energy and utilities ($3.3 million). These increases were offset by a $2.4 million reduction in rent expense. Direct operating expenses per barrel of crude throughput for the year ended December 31, 2004 increased by $0.08 per barrel compared to direct operating expenses per barrel of crude throughput of $2.57 in 2003.

Operating Income. Petroleum operating income was $77.1 million for the 304 days ended December 31, 2004 and $7.7 million for the 62 days ended March 2, 2004 as compared to $21.5 million in the year ended December 31, 2003. This increase for the combined periods for the year ended December 31, 2004 compared to the year ended December 31, 2003 primarily resulted

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from higher refining margin due to improved conditions in the domestic refining industry and a 6% increase in sales volumes. The increase in operating income was somewhat offset by increases in expenses related to environmental compliance ($1.1 million), repairs and maintenance ($2.8 million), chemicals ($2.3 million) and energy and utilities ($3.3 million).

Nitrogen Fertilizer Business Results of Operations

Nitrogen Fertilizer Business Financial Results	Original Predecessor Year Ended December 31, 2003	Original Predecessor 62 Days Ended March 2, 2004	Immediate Predecessor 304 Days Ended December 31, 2004	Immediate Predecessor 174 Days Ended June 23, 2005	Successor 233 Days Ended December 31, 2005	Successor Year Ended December 31, 2006	Successor Six Months Ended June 30, 2006	Successor Six Months Ended June 30, 2007
			(in millions)				(unaudited)	
Net sales	$ 100.9	$ 19.4	$ 93.4	$ 79.3	$ 93.7	$ 162.5	$ 95.6	$ 74.3
Cost of product sold (exclusive of depreciation and amortization)	21.9	4.1	20.4	9.1	14.5	25.9	15.6	6.2
Depreciation and amortization	1.2	0.1	0.9	0.3	8.4	17.1	8.4	8.8
Direct operating expenses (exclusive of depreciation and amortization)	53.0	8.4	43.8	28.3	29.2	63.7	28.7	33.2
Costs associated with flood								0.1
Operating income	7.8	3.5	22.9	35.3	35.7	36.8	37.1	21.0

Market Indicators	Year Ended December 31, 2003	2004	2005	2006	Six Months Ended June 30, 2006	2007
Natural gas (dollars per million Btu)	$ 5.49	$ 6.18	$ 9.01	$ 6.98	$ 7.24	$ 7.41
Ammonia southern plains (dollars per ton)	274	297	356	353	387	395
UAN corn belt (dollars per ton)	143	171	212	197	208	265

Company Operating Statistics	Original Predecessor 2003	Original Predecessor and Immediate Predecessor Combined 2004	Immediate Predecessor and Successor Combined 2005	Successor 2006	Successor Six Months Ended June 30, 2006	Successor Six Months Ended June 30, 2007
	Year Ended December 31,					
Production (thousand tons):						
Ammonia	335.7	309.2	413.2	369.3	205.6	169.0
UAN	510.6	532.6	663.3	633.1	328.3	304.6
Total	846.3	841.8	1,076.5	1,002.4	533.9	473.6
Sales (thousand tons)(1):						
Ammonia	134.8	103.9	141.8	117.3	66.3	34.1
UAN	528.9	541.6	646.5	645.5	339.3	293.5
Total	663.7	645.5	788.3	762.8	405.6	327.6
Product pricing (plant gate) (dollars per ton)(1):						
Ammonia	$ 235	$ 266	$ 324	$ 338	$ 376	$ 354
UAN	107	136	173	$ 162	$ 181	$ 190
On-stream factor(2):						
Gasification	90.1%	92.4%	98.1%	92.5%	97.3%	90.6%
Ammonia	89.6%	79.9%	96.7%	89.3%	94.7%	86.8%
UAN	81.6%	83.3%	94.3%	88.9%	93.8%	81.9%
Capacity utilization:						
Ammonia(3)	83.6%	76.8%	102.9%	92.0%	103.2%	84.9%
UAN(4)	93.3%	97.0%	121.2%	115.6%	120.9%	112.2%
Reconciliation to net sales (dollars in thousands):						
Freight in revenue	$ 12,535	$ 11,429	$ 15,010	$ 17,890	$ 9,441	$ 6,430
Sales net plant gate	88,373	101,439	157,989	144,575	$ 86,191	$ 67,905
Total net sales	100,908	112,868	172,999	162,465	$ 95,632	$ 74,334

(1) Plant gate sales per ton represents net sales less freight revenue divided by sales tons. Plant gate pricing per ton is shown in order to provide industry comparability.

(2) On-stream factor is the total number of hours operated divided by the total number of hours in the reporting period. Excluding the impact of turnarounds at the fertilizer facility in the third quarter of 2004 and 2006, (i) the on-stream factors in 2004 would have been 95.6% for gasification, 82.8% for ammonia and 86.1% for UAN, and (ii) the on-stream factors in 2006 would have been 97.1% for gasification, 94.3% for ammonia and 93.6% for UAN.

(3) Based on nameplate capacity of 1,100 tons per day.

(4) Based on nameplate capacity of 1,500 tons per day.

Six Months Ended June 30, 2007 Compared to the Six Months Ended June 30, 2006.

Net Sales. Nitrogen fertilizer net sales were $74.3 million for the six months ended June 30, 2007 compared to $95.6 million for the six months ended June 30, 2006. The decrease of $21.3 million from the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was the result of reductions in overall sales volumes ($21.5 million), partially offset by slightly higher plant gate prices ($0.2 million).

In regard to product sales volumes for the six months ended June 30, 2007, our nitrogen operations experienced a decrease of 49% in ammonia sales unit volumes (32,158 tons) and a decrease of 14% in UAN sales unit volumes (45,708 tons). The decrease in ammonia sales volume was the result of decreased production volumes during the six months ended June 30, 2007 relative to the comparable period of 2006 due to unscheduled downtime at our fertilizer plant and the transfer of hydrogen to our Petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit. The transfer of hydrogen to our Petroleum operations is scheduled to be replaced with hydrogen produced by the new continuous catalytic reformer scheduled to be completed by the beginning of 2008. On-stream factors (total number of hours operated divided by total hours in the reporting period) for all units of our nitrogen operations (gasifier, ammonia plant and UAN plant) were less than the comparable period primarily due to a two day outage at the air separation unit and eleven days of downtime as a result of a mechanical failure on restart at the nitric acid unit. It is typical to experience brief outages in complex manufacturing operations such as our nitrogen fertilizer plant which result in less than one hundred percent on-stream availability for one or more specific units.

Plant gate prices are prices FOB the delivery point less any freight cost we absorb to deliver the product. We believe plant gate price is meaningful because we sell products both FOB our plant gate (sold plant) and FOB the customer s designated delivery site (sold delivered) and the percentage of sold plant versus sold delivered can change month to month or six months to six months. The plant gate price provides a measure that is consistently comparable period to period. Plant gate prices for the six months ended June 30, 2007 for ammonia were less than plant gate prices for the comparable period of 2006 by 6%. In contrast, UAN plant gate prices for the six months ending June 30, 2007 were greater than the comparable period of 2006 by 5%. Our ammonia and UAN sales prices for product shipped during the six months ended June 30, 2006 benefited from a period of relatively high natural gas prices in 2005 primarily driven by the impact of hurricanes Katrina and Rita. It is typical for the reported pricing in our fertilizer business to lag the spot market prices due to forward price contracts. As a result, forward price contracts entered into the late summer and fall of 2005 comprised a significant portion of the product shipped in the six months ended June 30, 2006 and therefore reflect higher nitrogen fertilizer prices associated with the aforementioned increase in natural gas prices. In contrast, sales in the six months ended June 30, 2007 were primarily executed in late summer and fall of 2006 and in a comparably lower natural gas price environment, ahead of the recent rise in nitrogen fertilizer prices driven by expanded use of corn for the production of ethanol. Spot sales and fill contracts entered into and shipped during the six months ending June 30, 2007 helped to mitigate the negative comparison due to the forward contracts.

The demand for fertilizer is affected by the aggregate crop planting decisions and fertilizer application rate decisions of individual farmers. Individual farmers make planting decisions based largely on the prospective profitability of a harvest, while the specific varieties and amounts of fertilizer they apply depend on factors like crop prices, their current liquidity, soil conditions, weather patterns and the types of crops planted.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of pet coke expense, hydrogen reimbursement and freight and distribution expenses. Cost of product sold excluding depreciation and amortization for the six months ended June 30, 2007 was $6.2 million compared to $15.6 million for the six months ended June 30, 2006. The decrease of $9.4 million for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was primarily the result of increased hydrogen reimbursement due to the transfer of hydrogen to our Petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit and reduced freight expense partially offset by an increase in petroleum coke costs.

Costs Associated with Flood. Nitrogen Fertilizer costs associated with the flood for the six months ended June 30, 2007 approximated $0.1 million as compared to none for the six months ended June 30, 2006.

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization increased to $8.8 million for the six months ended June 30, 2007 as compared to $8.4 million for the six months ended June 30, 2006.

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Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Nitrogen fertilizer operations include costs associated with the actual operations of our nitrogen plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen direct operating expenses exclusive of depreciation and amortization for the six months ended June 30, 2007 were $33.2 million as compared to $28.7 million for the six months ended June 30, 2006. The increase of $4.5 million for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was primarily the result of increases in labor ($0.3 million), repairs and maintenance ($3.2 million), equipment rental ($0.4 million), outside services ($0.3 million), utilities ($1.2 million) and insurance ($0.3 million). The increase in repairs and maintenance expense was specifically related to preventative maintenance performed during a two day air separation unit outage and repairs to the nitric acid plant during the six months ended June 30, 2007. These increases in direct operating expenses were partially offset by reductions in expenses associated with turnaround ($0.3 million), slag removal ($0.2 million) and catalyst ($0.5 million).

Operating Income. Nitrogen fertilizer operating income was $21.0 million for the six months ended June 30, 2007 as compared to $37.1 million for the six months ended June 30, 2006. This decrease of $16.1 million for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was the result of reduced sales volumes ($21.5 million), partially offset by higher plant gate prices for both UAN and ammonia ($0.2 million) and increased direct operating expenses primarily the result of increases in labor ($0.3 million), repairs and maintenance ($3.2 million), equipment rental ($0.4 million), outside services ($0.3 million), utilities ($1.2 million) and insurance ($0.3 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with turnaround ($0.3 million), slag removal ($0.2 million) and catalyst ($0.5 million).

Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005.

Net Sales. Nitrogen fertilizer net sales were $162.5 million for the year ended December 31, 2006 compared to $79.3 million for the 174 days ended June 23, 2005 and $93.7 million for the 233 days ended December 31, 2005. The decrease of $10.5 million from the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was the result of both decreases in selling prices ($1.6 million) and reductions in overall sales volumes ($8.9 million) of the fertilizer products as compared to the year ended December 31, 2005.

In regard to product sales volumes for the year ended December 31, 2006, the nitrogen fertilizer operations experienced a decrease of 17% in ammonia sales unit volumes (24,500 tons) and a decrease of 0.2% in UAN sales unit volumes (988 tons). The decrease in ammonia sales volume was the result of decreased production volumes during the year ended December 31, 2006 relative to the comparable period of 2005 due to the scheduled turnaround at the fertilizer plant during July 2006 and the transfer of hydrogen to our Petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit. The transfer of hydrogen to our petroleum operations is scheduled to be replaced with hydrogen produced by the new continuous catalytic reformer scheduled to be completed in the fall of 2007. We do not expect this will be affected or changed due to our new Partnership structure for the nitrogen fertilizer business. On-stream factors (total number of hours operated divided by total hours in the reporting period) for all units of the nitrogen fertilizer operations (gasifier, ammonia plant and UAN plant) were less in 2006 than in 2005 primarily due to the scheduled turnaround in July 2006 and downtime in the ammonia plant due to a crack in the converter. It is typical to experience brief outages in complex manufacturing operations such as the nitrogen fertilizer plant which result in less than one hundred percent on-stream availability for one or more specific units.

Plant gate prices are prices FOB the delivery point less any freight cost absorbed to deliver the product. We believe plant gate price is meaningful because the nitrogen fertilizer business sells

products both FOB the plant gate (sold plant) and FOB the customer s designated delivery site (sold delivered) and the percentage of sold plant versus sold delivered can change month to month or year to year. The plant gate price provides a measure that is consistently comparable period to period. Plant gate prices for the year ended December 31, 2006 for ammonia were greater than plant gate prices for the comparable period of 2005 by 4%. In contrast to ammonia, UAN prices decreased for the year ended December 31, 2006 as compared to the year ended December 31, 2005 by 6%. The positive price comparisons for ammonia sales, given the dramatic decline in natural gas prices during the comparable periods, were the result of prepay contracts executed during the period of relatively high natural gas prices that resulted from the impact of hurricanes Katrina and Rita on an already tight natural gas market.

The demand for fertilizer is affected by the aggregate crop planting decisions and fertilizer application rate decisions of individual farmers. Individual farmers make planting decisions based largely on the prospective profitability of a harvest, while the specific varieties and amounts of fertilizer they apply depend on factors like crop prices, their current liquidity, soil conditions, weather patterns and the types of crops planted.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of pet coke expense and freight and distribution expenses. Cost of product sold excluding depreciation and amortization for the year ended December 31, 2006 was $25.9 million compared to $9.1 million for the 174 days ended June 23, 2005 and $14.5 million for the 233 days ended December 31, 2005. The increase of $2.3 million for the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was primarily the result of increases in freight expense.

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization increased to $17.1 million for the year ended December 31, 2006 as compared to $0.3 million for the 174 days ended June 23, 2005 and $8.4 million for the 233 days ended December 31, 2005. This increase of $8.4 million for the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was primarily the result of the step-up in property, plant and equipment for the Subsequent Acquisition. See Factors Affecting Comparability.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for the nitrogen fertilizer operations include costs associated with the actual operations of the fertilizer plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen direct operating expenses exclusive of depreciation and amortization for the year ended December 31, 2006 were $63.7 million as compared to $28.3 million for the 174 days ended June 23, 2005 and $29.2 million for the 233 days ended December 31, 2005. The increase of $6.2 million for the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was primarily the result of increases in labor ($0.7 million), repairs and maintenance ($0.5 million), turnaround expenses ($2.6 million), outside services ($0.6 million), utilities ($2.3 million) and insurance ($0.5 million), partially offset by reductions in expenses related to catalyst ($0.6 million) and environmental ($0.8 million).

Operating Income. Nitrogen fertilizer operating income was $36.8 million for the year ended December 31, 2006 as compared to $35.3 million for the 174 days ended June 23, 2005 and $35.7 million for the 233 days ended December 31, 2005. This decrease of $34.2 million for the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was the result of reduced sales volumes, lower plant gate prices for UAN and increased direct operating expenses related to labor ($0.7 million), repairs and maintenance ($0.5 million), turnaround expenses ($2.6 million), outside services ($0.6 million), utilities ($2.3 million), insurance ($0.5 million) and depreciation ($8.4 million), partially offset by reductions in expenses related to catalyst ($0.6 million) and environmental ($0.8 million) and higher ammonia prices.

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233 Days Ended December 31, 2005 and the 174 Days Ended June 23, 2005 Compared to the 304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004.

Net Sales. Nitrogen fertilizer net sales were $93.7 million for the 233 days ended December 31, 2005 and $79.3 million for the 174 days ended June 23, 2005 compared to $93.4 million for the 304 days ended December 31, 2004 and $19.4 million for the 62 days ended March 2, 2004. The increase of $60.1 million for the combined periods for the year ended December 31, 2005 as compared to the combined periods ended December 31, 2004 was the result of increases in both sales volumes ($33.2 million) and selling prices of ammonia and UAN ($26.9 million) as compared to 2004.

In regard to product sales volumes for the year ended December 31, 2005, nitrogen fertilizer experienced an increase of 36% in ammonia sales unit volumes (37,949 tons) and an increase of 19% in UAN sales unit volumes (104,982 tons) as compared to 2004. The increases in both ammonia and UAN sales were due to improved on-stream factors for all units of the nitrogen fertilizer operations (gasifier, ammonia plant and UAN plant) in 2005 as compared to 2004. On-stream factors in 2004 were negatively impacted during September 2004 by additional downtime from a scheduled turnaround, which resulted from delay in start-up associated with projects completed during the turnaround and outages in the ammonia plant to repair a damaged heat exchanger.

Plant gate prices are prices FOB the delivery point less any freight cost absorbed to deliver the product. We believe plant gate price is meaningful because the nitrogen fertilizer business sells products both FOB the plant gate (sold plant) and FOB the customer s designated delivery site (sold delivered) and the percentage of sold plant as compared to sold delivered can change month to month or year to year. The plant gate price provides a measure that is consistently comparable period to period. Plant gate prices in 2005 for ammonia and UAN were greater than 2004 by 22% and 27%, respectively. These prices reflected the strong market conditions in the nitrogen fertilizer business as reflected in relatively high natural gas prices during 2005.

The demand for fertilizer is affected by the aggregate crop planting decisions and fertilizer application rate decisions of individual farmers. Individual farmers make planting decisions based largely on the prospective profitability of a harvest, while the specific varieties and amounts of fertilizer they apply depend on factors like their current liquidity, soil conditions, weather patterns and the types of crops planted.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of pet coke expense and freight and distribution expenses. Cost of product sold excluding depreciation and amortization was $14.5 million for the 233 days ended December 31, 2005 and $9.1 million for the 174 days ended June 23, 2005 compared to $20.4 million for the 304 days ended December 31, 2004 and $4.1 million for the 62 days ended March 2, 2004. For the combined periods for the year ended December 31, 2005 as compared to the combined periods ended December 31, 2004, cost of product sold exclusive of depreciation and amortization decreased by $0.9 million.

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization was $8.4 million for the 233 days ended December 31, 2005 and $0.3 million for the 174 days ended June 23, 2005 compared to $0.9 million for the 304 days ended December 31, 2004 and $0.1 million for the 62 days ended March 2, 2004. The increase of $7.7 million for the combined periods ending December 31, 2005 as compared to the combined periods ended December 31, 2004 was primarily the result of the step-up in property, plant and equipment for the Subsequent Acquisition. See Factors Affecting Comparability.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for the nitrogen fertilizer operations include costs associated with the actual operations of the fertilizer plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen fertilizer direct operating expenses exclusive of depreciation and amortization were $29.2 million for the 233 days ended December 31, 2005 and $28.3 million for the 174 days ended June 23, 2005 compared to

$43.8 million for the 304 days ended December 31, 2004 and $8.4 million for the 62 days ended March 2, 2004. The increase of $5.3 million for the combined period ended December 31, 2005 as compared to the combined period ended December 31, 2004 was primarily the result of increases in labor ($1.9 million), outside services ($1.4 million), and energy and utilities costs ($3.8 million), partially offset by reductions in turnaround expenses ($1.8 million) and catalyst expense ($1.6 million).

Operating Income. Nitrogen fertilizer operating income was $35.7 million for the 233 days ended December 31, 2005 and $35.3 million for the 174 days ended June 23, 2005 compared to $22.9 million for the 304 days ended December 31, 2004 and $3.5 million for the 62 days ended March 2, 2004. The increase of $44.6 million for the combined periods ended December 31, 2005 as compared to the combined periods ended December 31, 2004 was due to improved sales volume and nitrogen fertilizer pricing that resulted from improved on-stream factors for the fertilizer plant and strong market conditions in the nitrogen fertilizer business. These positive factors were partially offset by increased direct operating expenses due to increases in labor ($1.9 million), outside services ($1.4 million), and energy and utilities costs ($3.8 million).

304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004 Compared to Year Ended December 31, 2003.

Net Sales. Nitrogen fertilizer net sales were $93.4 million for the 304 days ended December 31, 2004 and $19.4 million for the 62 days ended March 2, 2004 as compared to $100.9 million in 2003. This revenue increase for the combined periods of the year ended December 31, 2004 as compared to the year ended December 31, 2003 was entirely attributable to increased nitrogen fertilizer prices ($18.8 million), which more than offset a slight decline in total sales volume ($6.8 million) due to a planned turnaround in August 2004. For 2004, southern plains ammonia and corn belt UAN prices increased 8% and 20%, respectively, as compared to the comparable period in 2003. In addition, due to direct marketing efforts, the nitrogen fertilizer business actual plant gate prices, relative to the market indices presented above, improved substantially. Plant gate prices for the year ended December 31, 2004 for ammonia and UAN were greater than the comparable period in 2003 by 13% and 27%, respectively. Plant gate prices are prices FOB the delivery point less any freight cost absorbed to deliver the product. We believe the plant gate price is meaningful because the nitrogen fertilizer business sells products both FOB the plant gate (sold plant) and FOB the customer s designated delivery site (sold delivered) and the percentage of sold plant versus sold delivered can change month to month or year to year. The plant gate price provides a measure that is consistently comparable period to period. The improvement in plant gate price relative to the market index was the result of eliminating the reseller discount offered under the terms of a prior marketing agreement and maximizing shipments to customers that were more freight logical to the facility.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of pet coke expense and freight and distribution expenses. Cost of product sold excluding depreciation and amortization was $20.4 million for the 304 days ended December 31, 2004 and $4.1 million for the 62 days ended March 2, 2004 as compared to $21.9 million in 2003. The increase for the combined periods of the year ended December 31, 2004 as compared to the year ended December 31, 2003 was primarily the result of the recognition of the cost of pet coke after the Initial Acquisition as compared to a zero value transfer during the Original Predecessor period. Subsequent to the Initial Acquisition in 2004 the nitrogen fertilizer business was charged $4.3 million for pet coke transferred from our petroleum business. During the Original Predecessor period, pet coke was transferred at zero value.

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization was $0.9 million for the 304 days ended December 31, 2004 and $0.1 million for the 62 days ended March 2, 2004 as compared to $1.2 million in 2003. This decrease for the combined periods of the year ended December 31, 2004 and the year ended December 31, 2003 was principally due to the nitrogen fertilizer assets useful lives being reset to longer periods in the Initial Acquisition period compared to the prior period based on management s assessment of the condition of the nitrogen fertilizer assets acquired offset by the impact of the step-up in value of the acquired nitrogen fertilizer assets in the Initial Acquisition.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for the nitrogen fertilizer operations include costs associated with the actual operations of the fertilizer plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen fertilizer direct operating expenses exclusive of depreciation and amortization were $43.8 million for the 304 days ended December 31, 2004 and $8.4 million for the 62 days ended March 2, 2004 as compared to $53.0 million for the year ended December 31, 2003.

Operating Income. Nitrogen fertilizer operating income was $22.9 million for the 304 days ended December 31, 2004 and $3.5 million for the 62 days ended March 2, 2004 as compared to $7.8 million in 2003. This increase of $18.6 million for the combined periods of the year ended December 31, 2004 and the year ended December 31, 2003 was due to improved market conditions and pricing in the domestic nitrogen fertilizer industry and a decrease in direct operating expenses. The improvement in operating income was negatively impacted subsequent to the Initial Acquisition in 2004 as the nitrogen fertilizer business was charged $4.3 million for pet coke transferred from our petroleum business. During the Original Predecessor period, pet coke was transferred at zero value.

Consolidated Results of Operations

Six Months Ended June 30, 2007 Compared to the Six Months Ended June 30, 2006.

Net Sales. Consolidated net sales were $1,233.9 million for the six months ended June 30, 2007 compared to $1,550.6 million for the six months ended June 30, 2006. The decrease of $316.7 million for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was primarily due to a decrease in petroleum net sales of $296.3 million that resulted from lower sales volumes ($366.6 million), partially offset by higher product prices ($70.3 million). Nitrogen fertilizer net sales decreased $21.3 million for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 due to lower sales volumes ($21.5 million), partially offset by slightly higher plant gate prices ($0.2 million).

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $873.3 million for the six months ended June 30, 2007 as compared to $1,203.4 million for the six months ended June 30, 2006. The decrease of $330.1 million for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was primarily due to the refinery turnaround that began in February 2007 and was completed in April 2007. Our fertilizer business accounted for approximately $9.4 million of the decrease in cost of products sold over the comparable period primarily the result of increased hydrogen reimbursement due to the transfer of hydrogen to our Petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit and reduced freight expense partially offset by an increase in petroleum coke costs.

Costs Associated with Flood. Consolidated costs associated with the flood for the six months ended June 30, 2007 approximated $2.1 million as compared to none for the six months ended June 30, 2006. The costs associated with the flood for the six months ended June 30, 2007 include primarily write-offs of property and inventories that are uninsured due to our insurance deductibles. See Factors Affecting Comparability 2007 Flood and Crude Oil Discharge.

Depreciation and Amortization. Consolidated depreciation and amortization was $32.2 million for the six months ended June 30, 2007 as compared to $24.0 million for the six months ended June 30, 2006. The increase of $8.2 million for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was primarily the result of the completion of several large capital projects in late 2006 and during the six months ending June 30, 2007 in our Petroleum business.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Consolidated direct operating expenses exclusive of depreciation and amortization were $174.4 million for the six months ended June 30, 2007 as compared to $87.8 million for the six months ended June 30, 2006. This increase of $86.6 million for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was due to an increase in petroleum direct operating expenses of $82.0 million, primarily related to the refinery turnaround, and an increase in nitrogen fertilizer direct operating expenses of $4.5 million.

Selling, General and Administrative Expenses Exclusive of Depreciation and Amortization. Consolidated selling, general and administrative expenses were $28.1 million for the six months ended June 30, 2007 as compared to $20.5 million for the six months ended June 30, 2006. This variance was primarily the result of increases in administrative labor related to increased headcount and deferred compensation ($5.5 million), office costs ($0.4 million) and other costs ($0.7 million).

Operating Income. Consolidated operating income was $123.8 million for the six months ended June 30, 2007 as compared to operating income of $214.9 million for the six months ended June 30, 2006. For the six months ended June 30, 2007 as compared to the six months ended June 30, 2006, petroleum operating income decreased by $75.1 million and nitrogen fertilizer operating income decreased by $16.1 million.

Interest Expense. Consolidated interest expense for the six months ended June 30, 2007 was $27.6 million as compared to interest expense of $22.3 million for the six months ended June 30, 2006. This 24% increase for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 primarily resulted from an overall increase in the index rates (primarily LIBOR) and an increase in average borrowings outstanding during the six months ended June 30, 2007. Partially offsetting these negative impacts on consolidated interest expense was a $2.5 million increase in capitalized interest over the comparable period due to the increase of capital projects in progress during the six months ended June 30, 2007. Additionally, consolidated interest expense during the six months ended June 30, 2007 benefited from decreases in the applicable margins under our Credit Facility dated December 28, 2006 as compared to our borrowing facility completed in association with the Subsequent Acquisition that was in effect during the six months ended June 30, 2006. See Liquidity and Capital Resources Debt.

Interest Income. Interest income was $0.6 million for the six months ended June 30, 2007 as compared to $1.7 million for the six months ended June 30, 2006.

Gain (loss) on Derivatives. For the six months ended June 30, 2007, we incurred $292.4 million in losses on derivatives. This compares to a $126.5 million loss on derivatives for the six months ended June 30, 2006. This significant change in gain (loss) on derivatives for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was primarily attributable to our Cash Flow Swap and the accounting treatment for all of our derivative transactions. We determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Since the Cash Flow Swap had a significant term remaining as of June 30, 2007 (approximately two years and nine months) and the NYMEX crack spread that is the basis for the underlying swap contracts that comprised the Cash Flow Swap had increased during this period, the unrealized losses on the Cash Flow Swap increased significantly.

Provision for Income Taxes. Income tax benefit for the six months ended June 30, 2007 was approximately $141.0 million, or 72.09% of loss before income taxes, as compared to income tax expense of approximately $25.7 million, or 38.12% of earnings before income taxes, for the six months ended June 30, 2006. The annualized effective tax rate for 2007, which was applied to loss before income taxes for the six month period ended June 30, 2007, is higher than the comparable annualized effective tax rate for 2006, which was applied to earnings before income taxes for the six month period ended June 30, 2006, primarily due to the correlation between the amount of credits which are projected to be generated in 2007 from the production of ultra low sulfur diesel fuel and the reduced level of projected earnings before income taxes for 2007.

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Minority Interest in (income) loss of Subsidiaries. Minority interest in (income) loss of subsidiaries for the six months ended June 30, 2007 was $0.2 million. Minority interest relates to common stock in two of our subsidiaries owned by our chief executive officer.

Net Income. For the six months ended June 30, 2007, net income decreased to a net loss of $54.3 million as compared to net income of $41.8 million for the six months ended June 30, 2006. Net income decreased $96.1 million for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006, primarily due to the refinery turnaround and a significant change in the value of the Cash Flow Swap over the comparable periods.

Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005.

Net Sales. Consolidated net sales were $3,037.6 million for the year ended December 31, 2006 compared to $980.7 million for the 174 days ended June 23, 2005 and $1,454.3 million for the 233 days ended December 31, 2005. The increase of $602.6 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was primarily due to an increase in petroleum net sales of $613.2 million that resulted from significantly higher product prices ($384.1 million) and increased sales volumes ($229.1 million) over the comparable periods. Nitrogen fertilizer net sales decreased $10.5 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 due to decreased selling prices ($1.6 million) and a reduction in overall sales volumes ($8.9 million).

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $2,443.4 million for the year ended December 31, 2006 as compared to $768.0 million for the 174 days ended June 23, 2005 and $1,168.1 million for the 233 days ended December 31, 2005. The increase of $507.3 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was primarily due to an increase in crude oil prices, sales volumes and the impact of FIFO accounting in our petroleum business. The nitrogen fertilizer business accounted for approximately $2.3 million of the increase in cost of products sold over the comparable period primarily related to increases in freight expense.

Depreciation and Amortization. Consolidated depreciation and amortization was $51.0 million for the year ended December 31, 2006 as compared to $1.1 million for the 174 days ended June 23, 2005 and $24.0 million for the 233 days ended December 31, 2005. The increase of $25.9 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was due to an increase in petroleum depreciation and amortization of $16.6 million and an increase in nitrogen fertilizer depreciation and amortization of $8.4 million.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Consolidated direct operating expenses exclusive of depreciation and amortization were $199.0 million for the year ended December 31, 2006 as compared to $80.9 million for the 174 days ended June 23, 2005 and $85.3 million for the 233 days ended December 31, 2005. This increase of $32.8 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was due to an increase in petroleum direct operating expenses of $26.5 million and an increase in nitrogen fertilizer direct operating expenses of $6.2 million.

Selling, General and Administrative Expenses Exclusive of Depreciation and Amortization. Consolidated selling, general and administrative expenses were $62.6 million for the year ended December 31, 2006 as compared to $18.4 million for the 174 days ended June 23, 2005 and $18.4 million for the 233 days ended December 31, 2005. Consolidated selling, general and administrative expenses for the 174 days ended June 23, 2005 were negatively impacted by certain expenses associated with $3.3 million of unearned compensation related to the management equity of Immediate Predecessor in relation to the Subsequent Acquisition. Adjusting for this expense, consolidated selling, general and administrative expenses increased $29.1 million for the year ended

December 31, 2006 as compared to the combined periods ended December 31, 2005. This variance was primarily the result of increases in administrative labor related to increased headcount and share-based compensation ($18.6 million), office costs ($1.3 million), letter of credit fees due under our $150.0 million funded letter of credit facility utilized as collateral for the Cash Flow Swap which was not in place for approximately six months in the comparable period ($2.1 million), public relations expense ($0.5 million) and outside services expense ($2.4 million).

Operating Income. Consolidated operating income was $281.6 million for the year ended December 31, 2006 as compared to $112.3 million for the 174 days ended June 23, 2005 and $158.5 million for the 233 days ended December 31, 2005. For the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005, petroleum operating income increased $45.9 million and nitrogen fertilizer operating income decreased by $34.2 million.

Interest Expense. We reported consolidated interest expense for the year ended December 31, 2006 of $43.9 million as compared to interest expense of $7.8 million for the 174 days ended June 23, 2005 and $25.0 million for the 233 days ended December 31, 2005. This 34% increase for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was the direct result of increased average borrowings over the comparable periods associated with both our Credit Facility dated December 28, 2006 and our borrowing facility completed in association with the Subsequent Acquisition and an increase in the actual rate of our borrowings due primarily to increases both in index rates (LIBOR and prime rate) and applicable margins. See Liquidity and Capital Resources Debt. The comparability of interest expense during the comparable periods has been impacted by the differing capital structures of Successor and Immediate Predecessor periods. See Factors Affecting Comparability.

Interest Income. Interest income was $3.5 million for the year ended December 31, 2006 as compared to $0.5 million for the 174 days ended June 23, 2005 and $1.0 million for the 233 days ended December 31, 2005. The increase for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was primarily due to larger cash balances and higher yields on invested cash.

Gain (loss) on Derivatives. For the year ended December 31, 2006, we reported $94.5 million in gains on derivatives. This compares to a $7.7 million loss on derivatives for the 174 days ended June 23, 2005 and a $316.1 million loss on derivatives for the 233 days ended December 31, 2005. This significant change in gain (loss) on derivatives for the year ended December 31, 2006 as compared to the combined period ended December 31, 2005 was primarily attributable to our Cash Flow Swap and the accounting treatment for all of our derivative transactions. We determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Since the Cash Flow Swap had a significant term remaining as of December 31, 2006 (approximately three years and six months) and the NYMEX crack spread that is the basis for the underlying swap contracts that comprised the Cash Flow Swap had declined during this period, the unrealized gains on the Cash Flow Swap increased significantly. The $323.7 million loss on derivatives during the combined period ended December 31, 2005 is inclusive of the expensing of a $25.0 million option entered into by Successor for the purpose of hedging certain levels of refined product margins. At closing of the Subsequent Acquisition, we determined that this option was not economical and we allowed the option to expire worthless, which resulted in the expensing of the associated premium during the year ended December 31, 2005. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

Extinguishment of Debt. On December 28, 2006, Coffeyville Acquisition LLC refinanced its existing first lien credit facility and second lien credit facility and raised $1.075 billion in long-term debt commitments under the new Credit Facility. See Liquidity and Capital Resources Debt. As a result of the retirement of the first and second lien credit facilities with the proceeds of the Credit Facility, we recognized $23.4 million as a loss on extinguishment of debt in 2006. On June 24, 2005

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and in connection with the acquisition of Immediate Predecessor by Coffeyville Acquisition LLC, we raised $800.0 million in long-term debt commitments under both the first lien credit facility and second lien credit facility. See Factors Affecting Comparability and Liquidity and Capital Resources Debt. As a result of the retirement of Immediate Predecessor s outstanding indebtedness consisting of $150.0 million term loan and revolving credit facilities, we recognized $8.1 million as a loss on extinguishment of debt in 2005.

Other Income (Expense). For the year ended December 31, 2006, other expense was $0.9 million as compared to other expense of $0.8 million for the 174 days ended June 23, 2005 and other expense of $0.6 million for the 233 days ended December 31, 2005.

Provision for Income Taxes. Income tax expense for the year ended December 31, 2006 was $119.8 million, or 38.5% of earnings before income taxes, as compared to a tax benefit of $26.9 million, or 28.7% of earnings before income taxes, for the combined periods ended December 31, 2005. The effective tax rate for 2005 was impacted by a realized loss on option agreements that expired unexercised. Coffeyville Acquisition LLC was party to these agreements and the loss was incurred at that level which we effectively treated as a permanent non-deductible loss.

Net Income. For the year ended December 31, 2006, net income increased to $191.6 million as compared to net income of $52.4 million for the 174 days ended June 23, 2005 and a net loss of $119.2 million for the 233 days ended December 31, 2005. Net income increased $258.4 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005, primarily due to improved operating income in our Petroleum operations and a significant change in the value of the Cash Flow Swap over the comparable periods.

233 Days Ended December 31, 2005 and the 174 Days Ended June 23, 2005 Compared to the 304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004.

Net Sales. Consolidated net sales were $1,454.3 million for the 233 days ended December 31, 2005 and $980.7 million for the 174 days ended June 23, 2005 as compared to $1,479.9 million for the 304 days ended December 31, 2004 and $261.1 million for the 62 days ended March 2, 2004. This increase of $694.0 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was primarily due to an increase in petroleum net sales of $634.8 million that resulted from increased refined product prices ($688.3 million) offset by reduced sales volumes ($53.5 million) as compared to 2004. Also contributing to the increase in net sales during the comparable periods was a $60.1 million increase in nitrogen fertilizer net sales primarily driven by increase in both sales volumes ($33.2 million) and selling prices of ammonia and UAN ($26.9 million).

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $1,168.1 million for the 233 days ended December 31, 2005 and $768.1 million for the 174 days ended June 23, 2005 as compared to $1,244.2 million for the 304 days ended December 31, 2004 and $221.4 million for the 62 days ended March 2, 2004. This increase of $470.5 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was primarily due to increased crude oil prices partially offset by lower sales volumes and the impact of FIFO inventory valuation.

Depreciation and Amortization. Consolidated depreciation and amortization was $24.0 million for the 233 days ended December 31, 2005 and $1.1 million for the 174 days ended June 23, 2005 as compared to $2.4 million for the 304 days ended December 31, 2004 and $0.4 million for the 62 days ended March 2, 2004. This increase of $22.3 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was due to an increase in petroleum depreciation and amortization of $14.6 million and in nitrogen fertilizer depreciation and amortization of $7.7 million primarily the result of a step-up in property, plant and equipment for the Subsequent Acquisition. See Factors Affecting Comparability.

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Direct Operating Expenses Exclusive of Depreciation and Amortization. Consolidated direct operating expenses exclusive of depreciation and amortization were $85.3 million for the 233 days ended December 31, 2005 and $80.9 million for the 174 days ended June 23, 2005 as compared to $117.0 million for the 304 days ended December 31, 2004 and $23.4 million for the 62 days ended March 2, 2004. This increase of $25.8 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was due to an increase in petroleum direct operating expenses of $20.5 million and an increase in nitrogen fertilizer direct operating expenses of $5.3 million.

Selling, General and Administrative Expenses Exclusive of Depreciation and Amortization. Consolidated selling, general and administrative expenses were $18.3 million for the 233 days ended December 31, 2005 and $18.3 million for the 174 days ended June 23, 2005 as compared to $16.3 million for the 304 days ended December 31, 2004 and $4.6 million for the 62 days ended March 2, 2004. This increase of $15.7 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was primarily the result of increases in insurance costs associated with Successor s $1.25 billion property insurance limit requirement, letter of credit fees due under our $150.0 million funded letter of credit facility utilized as collateral for the Cash Flow Swap which was not in place in the prior period, management fees, discretionary bonuses and the write-off of unearned compensation associated with the Subsequent Acquisition.

Operating Income. Consolidated operating income was $158.5 million for the 233 days ended December 31, 2005 and $112.3 million for the 174 days ended June 23, 2005 as compared to $100.0 million for the 304 days ended December 31, 2004 and $11.2 million for the 62 days ended March 2, 2004. This increase of $159.6 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was the result of an increase in petroleum operating income of $114.9 million and an increase in nitrogen fertilizer operating income of $44.6 million.

Interest Expense. Consolidated interest expense was $25.0 million for the 233 days ended December 31, 2005 and $7.8 million for the 174 days ended June 23, 2005 as compared to $10.1 million for the 304 days ended December 31, 2004 and $0 for the 62 days ended March 2, 2004. This increase of $22.7 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was the direct result of increased borrowings in 2005 associated with our first tier credit facility and second tier credit facility completed in association with the Subsequent Acquisition and an increase in the actual rate of our borrowings due to both increases in index rates (LIBOR and prime rate) and applicable margins. See Liquidity and Capital Resources Debt. The comparability of 2005 and 2004 interest expense has been impacted by the differing capital structures of Successor, Immediate Predecessor and Original Predecessor. See Factors Affecting Comparability.

Interest Income. Interest income was $1.0 million for the 233 days ended December 31, 2005 and $0.5 million for the 174 days ended June 23, 2005 as compared to $0.2 million for the 304 days ended December 31, 2004 and $0.0 million for the 62 days ended March 2, 2004. This increase of $1.3 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was the result of larger cash balances and higher yields on invested cash.

Gain (loss) on Derivatives. Gain (loss) on derivatives was a loss of $316.1 million for the 233 days ended December 31, 2005 and a loss of $7.7 million for the 174 days ended June 23, 2005 as compared to a $0.5 million gain for the 304 days ended December 31, 2004 and $0 for the 62 days ended March 2, 2004. This dramatic decrease of $324.2 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 is the result of a dramatic increase in losses on derivatives primarily attributable to our Cash Flow Swap and the accounting treatment for all of our derivative transactions. We determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Therefore, the net income for the year ended December 31, 2005 included both the realized and the unrealized losses on all derivatives. Since the Cash Flow Swap had a significant term remaining as of December 31, 2005 (approximately four years) and the NYMEX crack spread that is the basis for the underlying swap contracts that comprised the Cash Flow Swap had improved substantially, the unrealized losses on the Cash Flow Swap increased significantly as of December 31, 2005. The impact of these unrealized losses on all derivatives, including the Cash Flow Swap, resulted in unrealized losses of $229.8 million for 2005. Realized losses on derivative transaction comprised the balance of the losses for 2005 or $93.9 million. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

Extinguishment of Debt. On June 24, 2005 and in connection with the acquisition of Immediate Predecessor by Coffeyville Acquisition LLC, we raised $800.0 million in long-term debt commitments under a first lien credit facility and a second lien credit facility. See Factors Affecting Comparability. As a result of the retirement of Immediate Predecessor s outstanding indebtedness consisting of $150.0 million term loan and revolving credit facilities, we recognized $8.1 million as a loss on extinguishment of debt in 2005. This compares to a loss on extinguishment of debt of $7.2 million for the year ended December 31, 2004. On May 10, 2004, we used proceeds from a $150.0 million term loan to pay off our then existing debt which was originally incurred on March 3, 2004. In connection with the extinguishment of debt, we recognized $7.2 million as a loss on extinguishment of debt in the 304 day period ended December 31, 2004.

Other Income (Expense). Other income (expense) was expense of $0.6 million for the 233 days ended December 31, 2005 and expense of $0.8 million for the 174 days ended June 23, 2005 as compared to income of $0.1 million for the 304 days ended December 31, 2004 and $0 for the 62 days ended March 2, 2004. This decrease of $1.4 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was primarily the result of asbestos related accruals in 2005.

Provision for Income Taxes. Our income tax benefit in the year ended December 31, 2005 was ($26.9 million), or 28.7% of loss before income tax, as compared to $33.8 million in 2004. The effective tax rate for 2005 was impacted by a realized loss on option agreements that expired unexercised. Coffeyville Acquisition LLC was the party to these agreements and the loss was incurred at that level which we effectively treated as a permanent non-deductible loss, therefore generating a lower effective tax rate on the net loss for the year.

Net Income. Net income was a loss of $119.2 million for the 233 days ended December 31, 2005 and net income of $52.4 million for the 174 days ended June 23, 2005 as compared to net income of $49.7 million for the 304 days ended December 31, 2004 and net income of $11.2 million for the 62 days ended March 2, 2004. This decrease of $127.7 million for the combined periods ended December 31, 2005 compared to the combined periods ended December 31, 2004 was primarily due to losses on derivatives offset by improved margins in the year ending December 31, 2005 as compared to 2004.

304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004 Compared to Year Ended December 31, 2003.

Net Sales. Consolidated net sales were $1,479.9 million for the 304 days ended December 31, 2004 and $261.1 million for the 62 days ended March 2, 2004 compared to $1,262.2 million for the year ended December 31, 2003. The increase of $478.8 million for the combined periods of the year ended December 31, 2004 compared to the year ended December 31, 2003 was primarily due to an increase in petroleum net sales of $471.1 million due to both increased sales volumes ($83.2 million) and increased refined product prices ($387.9 million). Nitrogen fertilizer net sales increased $12.0 million in the combined periods of the year ended December 31, 2004 as compared to the year

ended December 31, 2003 as a result of improved nitrogen fertilizer prices ($18.8 million), offset by a decline in overall fertilizer sales volume ($6.8 million).

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $1,244.2 million for the 304 days ended December 31, 2004 and $221.4 million for the 62 days ended March 2, 2004 compared to $1,061.9 million for the year ended December 31, 2003. This increase of $403.8 million for the combined periods of the year ended December 31, 2004 compared to the year ended December 31, 2003 was primarily due to an increase in crude oil costs and increased crude throughput in our petroleum business for the year ended December 31, 2004 as compared to the year ended December 31, 2003. Nitrogen fertilizer cost of product sold also increased in the comparable periods primarily due to the recognition of the cost of pet coke after the Initial Acquisition as compared to zero value transfer during the Original Predecessor period.

Depreciation and Amortization. Consolidated depreciation and amortization was $2.4 million for the 304 days ended December 31, 2004 and $0.4 million for the 62 days ended March 2, 2004 compared to $3.3 million for the year ended December 31, 2003. This decrease of $0.5 million for the combined periods of the year ended December 31, 2004 compared to the year ended December 31, 2003 was due to a decrease in petroleum depreciation and amortization of $0.3 million and a decrease in nitrogen fertilizer depreciation and amortization of $0.2 million.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Consolidated direct operating expenses exclusive of depreciation and amortization were $117.0 million for the 304 days ended December 31, 2004 and $23.4 million for the 62 days ended March 2, 2004 compared to $133.1 million for the year ended December 31, 2003. The increase of $7.2 million for the combined periods of the year ended December 31, 2004 compared to the year ended December 31, 2003 was primarily due to an increase in petroleum direct operating expenses of $8.1 million. This increase in the petroleum business was partially offset by a decrease in nitrogen fertilizer direct operating expenses of $0.8 million.

Operating Income. Consolidated operating income was $100.0 million for the 304 days ended December 31, 2004 and $11.2 million for the 62 days ended March 2, 2004 compared to $29.4 million for the year ended December 31, 2003. For the combined periods of the year ended December 31, 2004 compared to the year ended December 31, 2003, petroleum operating income increased $63.3 million and nitrogen fertilizer operating income increased by $18.6 million.

Selling, General and Administrative Expenses Exclusive of Depreciation and Amortization, Reorganization Expenses and Interest Expense. Consolidated selling, general and administrative expenses were $16.3 million for the 304 days ended December 31, 2004 and $4.7 million for the 62 days ended March 2, 2004 compared to $23.6 million for the year ended December 31, 2003. The $16.3 million of consolidated selling, general and administrative expenses for the 304 days ended December 31, 2004 represented the cost associated with corporate governance, legal expenses, treasury, accounting, marketing, human resources and maintaining corporate offices in New York and Kansas City. During the predecessor periods, Farmland allocated corporate overhead based on internal needs, which may not have been representative of the actual cost to operate the businesses. In addition, during the year ended December 31, 2003, Farmland incurred a number of charges related to its bankruptcy. As a result of the charges and issues related to allocations, a comparison of selling, general and administrative expenses for the year ended December 31, 2004 to the year ended December 31, 2003 is not meaningful.

Extinguishment of Debt. On May 10, 2004, we used proceeds from a $150.0 million dollar term loan to pay off our then existing debt which was originally incurred on March 3, 2004. In connection with the extinguishment of debt, we recognized $7.2 million as a loss on extinguishment of debt in the 304 day period ended December 31, 2004.

Provision for Income Taxes. Original Predecessor was not a separate legal entity, and its operating results were included with the operating results of Farmland and its subsidiaries in filing consolidated federal and state income tax returns. Farmland did not allocate income taxes to its divisions. As a result, Original Predecessor periods do not reflect any provision for income taxes.

Net Income. Net income was $49.7 million for the 304 days ended December 31, 2004 and $11.2 million for the 62 days ended March 2, 2004 compared to $27.9 million for the year ended December 31, 2003. This increase of $33.0 million for the combined periods of the year ended December 31, 2004 compared to the year ended December 31, 2003 was due to both the change in ownership and improved results in both the petroleum business and the nitrogen fertilizer business.

Critical Accounting Policies

We prepare our consolidated financial statements in accordance with GAAP. In order to apply these principles, management must make judgments, assumptions and estimates based on the best available information at the time. Actual results may differ based on the accuracy of the information utilized and subsequent events. Our accounting policies are described in the notes to our audited financial statements included elsewhere in this prospectus. Our critical accounting policies, which are described below, could materially affect the amounts recorded in our financial statements.

Impairment of Long-Lived Assets

During 2001, Farmland accounted for long-lived assets in accordance with SFAS No. 121, *Accounting for Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of.* SFAS 121 was superseded by SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which was adopted by Farmland effective January 1, 2002.

In accordance with both SFAS 144 and SFAS 121, Farmland reviewed its long-lived assets for impairment whenever events or changes in circumstances indicated that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future net cash flows expected to be generated by the asset. If the carrying amount of an asset exceeded its estimated future undiscounted net cash flows, an impairment charge was recognized by the amount by which the carrying amount of the assets exceeded the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying value or fair value less cost to sell, and are no longer depreciated.

In its Plan of Reorganization, Farmland stated, among other things, its intent to dispose of its petroleum and nitrogen fertilizer assets. Despite this stated intent, these assets were not classified as held for sale under SFAS 144 until October 7, 2003 because, ultimately, any disposition must be approved by the bankruptcy court and the bankruptcy court did not approve such disposition until that date. Since Farmland determined that it was more likely than not that its assets would be disposed of, those assets were tested for impairment in 2002 pursuant to SFAS 144, using projected undiscounted net cash flows. Based on Farmland s best assumptions regarding the use and eventual disposition of those assets, primarily from indications of value received from potential bidders in the bankruptcy sales process, the assets were determined to exceed the fair value expected to be received on disposition by approximately $375.1 million. Accordingly, an impairment charge was recognized for that amount in 2002. The ultimate proceeds from disposition of these assets were decided in a bidding and auction process conducted in the bankruptcy proceedings. In 2003, as a result of receiving a bid from Coffeyville Resources, LLC, Farmland revised its estimate of the amount to be generated from the disposition of these assets and an additional impairment charge of $9.6 million was taken in the year ended December 31, 2003.

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As of June 30, 2007, net property, plant and equipment totaled $1,158.0 million. To the extent events or circumstances change indicating the carrying amounts of our assets may not be recoverable, we could experience asset impairments in the future.

Derivative Instruments and Fair Value of Financial Instruments

We use futures contracts, options, and forward contracts primarily to reduce exposure to changes in crude oil prices, finished goods product prices and interest rates to provide economic hedges of inventory positions and anticipated interest payments on long term-debt. Although management considers these derivatives economic hedges, the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and accordingly are recorded at fair value in the balance sheet. Changes in the fair value of these derivative instruments are recorded into earnings as a component of other income (expense) in the period of change. The estimated fair values of forward and swap contracts are based on quoted market prices and assumptions for the estimated forward yield curves of related commodities in periods when quoted market prices are unavailable. The Company recorded net gains (losses) from derivative instruments of ($323.7 million), $94.5 million and $(292.4) million in gain (loss) on derivatives for the fiscal years ended December 31, 2005 and 2006 and for the six months ended June 30, 2007, respectively.

As of June 30, 2007, a $1.00 change in quoted prices for the crack spreads utilized in the Cash Flow Swap would result in a $54.8 million change to the fair value of derivative commodity position and the same change to net income.

Environmental Expenditures

Liabilities related to future remediation of contaminated properties are recognized when the related costs are considered probable and can be reasonably estimated. Estimates of these costs are based upon currently available facts, existing technology, site-specific costs, and currently enacted laws and regulations. In reporting environmental liabilities, no offset is made for potential recoveries. All liabilities are monitored and adjusted as new facts or changes in law or technology occur. Environmental expenditures are capitalized when such costs provide future economic benefits. Changes in laws, regulations or assumptions used in estimating these costs could have a material impact to our financial statements. The amount recorded for environmental obligations at June 30, 2007 totaled $7.0 million, including $1.4 million included in current liabilities.

Share-Based Compensation

We estimated fair value of units for all applicable periods as described below.

At March 3, 2004, we determined the per unit value of the Original Predecessor common units by assessing the fair value of the preference components associated with the preferred units based on expected future cash flows of the business and subtracting that value from the total fair value of our equity to arrive at a fair value of the residual interests of the preferred and common units.

In addition to voting rights, the holders of the preferred units, who contributed all the cash into the Original Predecessor on the acquisition date, were entitled to a return of their contributed capital plus a 15% per annum preferred yield on any outstanding unreturned contributed capital. In determining the value that the preferred unit holders transferred to the common unit holders, rather than applying a waterfall method which would have resulted in no value, we applied a discounted cash flow analysis based on a range of potential earnings outcomes and assumptions. The percent of equity value transferred from the preferred unit holders to the common unit holders was based on the discounted cash flow analysis after giving effect to the preference obligations, including the 15% per annum preferred yield. Changes in assumptions such as discount rates, prices or operating plant operating conditions used to determine the forecasted cash flows used in the valuation could have a material impact on the percent of equity value allocated to the common units. In preparing the

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discounted cash flow analysis, the product sales price assumptions used for the fertilizer and refinery products assumed sustained prices for a five-year period at historically high levels.

In connection with its refinancing on May 10, 2004, we had obtained independent third party appraisals for the refinery and the nitrogen fertilizer plant property, plant and equipment. Taking into account the third party appraisals, we calculated an equity value for the business. The appraisals included market approach valuations and income approach valuations in the form of a discounted cash flow. The discounted cash flow analysis included assumptions for product sales prices consistent with readily available forward market indicators and reflected existing plant performance measures. Changes in assumptions such as discount rates, prices or operating plant operating conditions used to determine the forecasted cash flows used in the valuation could have a material impact on the equity value. Given the refinancing allowed us to settle the preference obligations, the equity value resulting from the appraisal was allocated pro rata to all unit holders for the 74,852,941 shares outstanding subject to a discount of 8% attributed to the common units for the non-voting status.

For the 233 day period ended December 31, 2005, the year ended December 31, 2006 and the six months ended June 30, 2007, we account for share-based compensation in accordance with SFAS No. 123(R), *Share-Based Payments*. SFAS 123(R) requires that compensation costs relating to share-based payment transactions be recognized in a company s financial statements. SFAS 123(R) applies to transactions in which an entity exchanges its equity instruments for goods or services and also may apply to liabilities an entity incurs for goods or services that are based on the fair value of those equity instruments.

In accordance with SFAS 123(R), we apply a fair-value-based measurement method in accounting for share-based override units and phantom points. See Management Employment Agreements and Other Arrangements. Override units are equity classified awards measured using the grant date fair value with compensation expense recognized over the respective vesting period. Phantom points are liability classified awards marked to market based on their fair value at the end of each reporting period with compensation expense recognized over the respective vesting period.

At June 24, 2005 an independent third party appraisal for the refinery and the nitrogen fertilizer plant were obtained. Additionally, an independent appraisal process occurred at that time, to value the management common units that were subject to redemption and our override value units, override operating units and phantom points. The Monte Carlo method of valuation was utilized to value the override operating units, override value units and phantom points that were issued on June 24, 2005.

In addition, an independent appraisal process occurs each reporting period in order to revalue the management common units and phantom points. The significant assumptions that are used each reporting period to value the phantom and performance service points are: (1) estimated forfeiture rate; (2) explicit service period or derived service period as applicable, (3) grant-date fair value controlling basis; (4) marketability and minority interest discounts and (5) volatility.

For the independent valuations that occurred as of December 31, 2005, June 30, 2006 and September 30, 2006, a Binomial Option Pricing Model was utilized to value the phantom points. Probability-weighted values that were determined in this independent valuation process were discounted to determine the present value of the units. Prospective financial information is utilized in the valuation process. A discounted cash flow method, a variation of the income approach, and a guideline company method, which is a variation of a market approach is utilized to value the management common units.

A combination of a binomial model and a probability-weighted expected return method which utilizes the company s cash flow projections was utilized to value the additional override operating units and override value units that were issued on December 28, 2006. Additionally, this combination of a binomial model and probability-weighted expected return method was utilized to value the phantom points as of December 31, 2006. Management believes that this method is preferable for the valuation of the override units and phantom points as it allows a better integration of the cash flows

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with other inputs including the timing of potential exit events that impact the estimated fair value of the override units and phantom points.

There is considerable judgment in the determination of the significant assumptions used in determining the fair value for our share based compensation. Changes in these assumptions could result in material changes in the amounts recognized as compensation expense in our consolidated financial statements. For example, if we accelerated the expected term or maturity date of the override units as a result of a change in assumptions for the timeframe for when the override units begin to receive distributions (i.e., timing of an exit event), or increased the current value of the common units based on changes in the projected future cash flows of the business, the measurement date fair value of the override units and the phantom points could materially increase, which could materially increase the amount of compensation expense recognized in our consolidated financial statements. In addition, changes in the assumptions of discount rate, volatility, or free cash flows will impact the amount of compensation expense recognized. The extent of the impact is influenced by the expected term or maturity date of the override units and current value of the common units.

Assuming an override maturity date beyond ten years, which increases the strike price as a result of requiring a higher return on the common units before distributions are paid to the override units, any changes to the discount rate, volatility, or free cash flows that would increase compensation expense are largely offset by the increase in the strike price. Assuming a 25% increase in the projected free cash flows used in the analysis, additional compensation expense of approximately $11.5 million would be recognized over the vesting period related to the phantom points.

Purchase Price Accounting and Allocation

The Initial Acquisition and the Subsequent Acquisition described in Note 1 to our audited consolidated financial statements included elsewhere in this prospectus have been accounted for using the purchase method of accounting as of March 3, 2004 and June 24, 2005, respectively. The allocations of the purchase prices to the net assets acquired have been performed in accordance with SFAS No. 141, *Business Combinations.* In connection with the allocations of the purchase prices, management used estimates and assumptions to determine the fair value of the assets acquired and liabilities assumed. Changes in these assumptions and estimates such as discount rates and future cash flows used in the appraisal process could have a material impact on how the purchase prices were allocated at the dates of acquisition.

Income Taxes

Income tax expense is estimated based on the projected effective tax rate based upon future tax return filings. The amounts anticipated to be reported in those filings may change between the time the financial statements are prepared and the time the tax returns are filed. Further, because tax filings are subject to review by taxing authorities, there is also the risk that a position on a tax return may be challenged by a taxing authority. If the taxing authority is successful in asserting a position different than that taken by us, differences in a tax expense or between current and deferred tax items may arise in future periods. Any of these differences which could have a material impact on our financial statements would be reflected in the financial statements when management considers them probable of occurring and the amount reasonably estimatable.

Valuation allowances reduce deferred tax assets to an amount that will more likely than not be realized. Management s estimates of the realization of deferred tax assets is based on the information available at the time the financial statements are prepared and may include estimates of future income and other assumptions that are inherently uncertain. No valuation allowance is currently recorded, as we expect to realize our deferred tax assets.

Consolidation of Variable Interest Entities

In accordance with FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities*, or FIN No. 46R, management has reviewed the terms associated with our interests in the Partnership based upon the partnership agreement as it will apply when the managing general partner interest in the Partnership is sold. Management has determined that the Partnership will be treated as a variable interest entity and as such has evaluated the criteria under FIN 46R to determine that we are the primary beneficiary of the Partnership. FIN 46R requires the primary beneficiary of a variable interest entity s activities to consolidate the VIE. FIN 46R defines a variable interest entity as an entity in which the equity investors do not have substantive voting rights and where there is not sufficient equity at risk for the entity to finance its activities without additional subordinated financial support. As the primary beneficiary, we absorb the majority of the expected losses and/or receive a majority of the expected residual returns of the VIE s activities.

We will need to reassess our investment in the Partnership from time to time to determine whether we are the primary beneficiary. If in the future we conclude that we are no longer the primary beneficiary, we will be required to deconsolidate the activities of the Partnership on a going forward basis. The interest would then be recorded using the equity method and the Partnership gross revenues, expenses, net income, assets and liabilities as such would not be included in our consolidated financial statements.

Liquidity and Capital Resources

Our principal sources of liquidity are from cash and cash equivalents, cash from operations and borrowings under our subsidiaries credit facilities.

Cash Balance and Other Liquidity

As of June 30, 2007, we had cash, cash equivalents and short-term investments of $23.1 million. We believe our June 30, 2007 cash levels, together with the availability of borrowings under our subsidiaries credit facilities and the proceeds we receive from this offering, will be adequate to fund our cash requirements based on our current level of operations for at least the next twelve months. As of June 30, 2007, we had available up to $76.2 million under our revolving loan facilities. As of September 30, 2007, we had outstanding $20.0 million of revolver borrowings and aggregate availability of $168.1 million under both our revolving credit facility and the $75 million unsecured facility.

As of June 30, 2007, our working capital and total members equity were negatively impacted by the mark to market accounting treatment of the Cash Flow Swap. In addition, our working capital was negatively impacted by increased borrowings under our revolving credit facility and uses of cash for the refinery turnaround and significant capital expenditures. The payable to swap counterparty included in the consolidated balance sheet at June 30, 2007 was approximately $386.3 million, and the current portion included an increase of $230.2 million from December 31, 2006, resulting in an equal reduction in our working capital for that same period. If the unrealized portion of this obligation becomes realized during 2007 and we are required to satisfy the obligations associated with the realized losses, assuming the plant is operating in a commercially reasonable manner, we will have cash flows from operations sufficient to meet this obligation, as a result of the inherent nature of the Cash Flow Swap.

On June 30, 2007, our refinery and the nitrogen fertilizer plant were severely flooded and forced to conduct emergency shutdowns and evacuate. See Flood and Crude Oil Discharge. Our liquidity was significantly negatively impacted as a result of the reduction in cash provided by operations due to our temporary cessation of operations and the additional expenditures associated with the flood and crude oil discharge. In order to provide adequate immediate and future liquidity, on August 23, 2007 we deferred payments of $123.7 million which were due to J. Aron under the terms of the Cash Flow Swap, borrowed $50 million under new credit facilities and put in place additional borrowing availability of $75 million. The new credit facilities and the new borrowing availability mature, and the J. Aron deferred amounts will become due, in August 2008 (assuming completion of our initial public offering by January 31, 2008). See Liquidity and Capital Resources New Credit Facilities and Liquidity and Capital Resources Payment Deferrals Related to Cash Flow Swap for additional information about the new credit facilities and payment deferral.

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Debt

On December 28, 2006, our subsidiary Coffeyville Resources, LLC entered into a Credit Facility which provides financing of up to $1.075 billion. The Credit Facility consists of $775 million of tranche D term loans, a $150 million revolving credit facility, and a funded letter of credit facility of $150 million issued in support of the Cash Flow Swap. The Credit Facility is guaranteed by all of our subsidiaries and is secured by substantially all of their assets including the equity of our subsidiaries on a first lien priority basis.

The Credit Facility refinanced our then existing first lien credit facility and second lien credit facility, which were initially entered into on June 24, 2005 in conjunction with the Subsequent Acquisition. The first lien credit facility consisted of $225.0 million of tranche B term loans; $50 million of delayed draw term loans; a $100.0 million revolving loan facility; and a $150.0 million funded letter of credit facility issued in support of the Cash Flow Swap. The second lien credit facility consisted of a $275.0 million term loan. The first lien credit facility was amended and restated on June 29, 2006 on substantially the same terms as the June 24, 2005 agreement; the primary reason for the June 2006 amendment and restatement was to reduce the applicable margin spreads for borrowings on the first lien term loans and the funded letter of credit facility.

The $775.0 million of tranche D term loans are subject to quarterly principal amortization payments of 0.25% of the outstanding balance commencing on April 1, 2007 and increasing to 23.5% of the outstanding principal balance on April 1, 2013 and the next two quarters, with a final payment of the aggregate outstanding balance on December 28, 2013. Our first lien credit facility, now repaid in full, had a similar amortization schedule and prior to repayment in full we had made all of the quarterly principal amortization payments under that facility.

The revolving loan facility of $150.0 million provides for direct cash borrowings for general corporate purposes and on a short-term basis. Letters of credit issued under the revolving loan facility are subject to a $75.0 million sub-limit. The revolving loan commitment expires on December 28, 2012. The borrower has an option to extend this maturity upon written notice to the lenders; however, the revolving loan maturity cannot be extended beyond the final maturity of the term loans, which is December 28, 2013. As of December 31, 2006, we had available $143.6 million under the revolving credit facility.

The $150.0 million funded letter of credit facility provides credit support for our obligations under the Cash Flow Swap. The funded letter of credit facility is fully cash collateralized by the funding by the lenders of cash into a credit linked deposit account. This account is held by the funded letter of credit issuing bank. Contingent upon the requirements of the Cash Flow Swap, the borrower has the ability to reduce the funded letter of credit at any time upon written notice to the lenders. The funded letter of credit facility expires on December 28, 2010.

The net proceeds of $775.0 million received on December 28, 2006 from the term loans under the Credit Facility were used to repay the term loans under our then existing first lien credit facility, repay all amounts outstanding under our then existing second lien credit facility, pay related fees and expenses, and pay a dividend to existing members of Coffeyville Acquisition LLC in the amount of $250 million.

The net proceeds received in June 2005 from the tranche B term loan of $225.0 million under our then-existing first lien credit facility, second lien term loans of $275.0 million, $12.5 million of revolving loan facilities and a $227.7 million equity contribution from Coffeyville Acquisition LLC were utilized to fund the following upon the closing of the Subsequent Acquisition:

- $685.8 million for cash proceeds to Immediate Predecessor ($1,038.9 million of assets acquired less $353.1 million of liabilities assumed), including $12.6 million of legal, accounting, advisory, transaction and other expenses associated with the Subsequent Acquisition;

$49.6 million of other fees and expenses related to the Subsequent Acquisition, including financing fees, risk management fees associated with option premiums for crack spread swaps, and title fees; and

$4.9 million of cash to fund our operating accounts.

The Credit Facility incorporates the following pricing by facility type:

Tranche D term loans bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 2.25%, or, at the borrower s option, (b) LIBOR plus 3.25% (with step-downs to the prime rate/federal funds rate plus 1.75% or 1.50% or LIBOR plus 2.75% or 2.50%, respectively, upon achievement of certain rating conditions). Prior to the December 2006 amendment and restatement, first lien term loans accrued interest at (a) the greater of the prime rate and the federal funds rate plus 0.5%, plus in either case 1.25%, or, at the borrower s option, (b) LIBOR plus 2.25% (with potential stepdowns to LIBOR plus 2.00% or the prime rate plus 1.00%), and second lien term loans accrued interest at a rate of LIBOR plus 6.75% or, at the borrower s option, the prime rate plus 5.75%.

Revolving loan borrowings bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 2.25%, or, at the borrower s option, (b) LIBOR plus 3.25% (with step-downs to the prime rate/federal funds rate plus 1.75% or 1.50% or LIBOR plus 2.75% or 2.50%, respectively, upon achievement of certain rating conditions). Prior to the December 2006 amendment and restatement, revolving loans under the then-existing first lien credit facility accrued interest at (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 1.50%, or, at the borrower s option, (b) LIBOR plus 2.50% (with potential stepdowns to LIBOR plus 2.00% or the prime rate plus 1.00%).

Letters of credit issued under the $75.0 million sub-limit available under the revolving loan facility are subject to a fee equal to the applicable margin on revolving LIBOR loans owing to all revolving lenders and a fronting fee of 0.25% per annum owing to the issuing lender.

Funded letters of credit are subject to a fee equal to the applicable margin on term LIBOR loans owed to all funded letter of credit lenders and a fronting fee of 0.125% per annum owing to the issuing lender. The borrower is also obligated to pay a fee of 0.10% to the administrative agent on a quarterly basis based on the average balance of funded letters of credit outstanding during the calculation period, for the maintenance of a credit-linked deposit account backstopping funded letters of credit.

In addition to the fees stated above, the Credit Facility requires the borrower to pay 0.50% per annum in commitment fees on the unused portion of the revolving loan facility.

The Credit Facility requires the borrower to prepay outstanding loans, subject to certain exceptions, with:

100% of the net asset sale proceeds received from specified asset sales and net insurance/condemnation proceeds, if the borrower does not reinvest those proceeds in assets to be used in its business or make other permitted investments within 12 months or if, within 12 months of receipt, the borrower does not contract to reinvest those proceeds in assets to be used in its business or make other permitted investments within 18 months of receipt, each subject to certain limitations;

100% of the cash proceeds from the incurrence of specified debt obligations;

75% of consolidated excess cash flow less 100% of voluntary prepayments made during the fiscal year; provided that with respect to any fiscal year commencing with fiscal 2008 this percentage will be reduced to 50% if the total leverage ratio at the end of such fiscal year is less than 1.50:1.00 or 25% if the total leverage ratio as of the end of such fiscal year is less than 1.00:1.00; and

100% of the cash proceeds received by us from any initial public offering or secondary registered offering of equity interests, until the aggregate amount of such proceeds is equal to $280 million.

Mandatory prepayments will be applied first to the term loan, second to the swing line loans, third to the revolving loans, fourth to outstanding reimbursement obligations with respect to revolving letters of credit and funded letters of credit, and fifth to cash collateralize revolving letters of credit and funded letters of credit. Voluntary prepayments of loans under the Credit Facility are permitted, in whole or in part, at the borrower s option, without premium or penalty. This offering will trigger a mandatory prepayment of the Credit Facility.

The Credit Facility contains customary covenants. These agreements, among other things, restrict, subject to certain exceptions, the ability of Coffeyville Resources, LLC and its subsidiaries to incur additional indebtedness, create liens on assets, make restricted junior payments, enter into agreements that restrict subsidiary distributions, make investments, loans or advances, engage in mergers, acquisitions or sales of assets, dispose of subsidiary interests, enter into sale and leaseback transactions, engage in certain transactions with affiliates and stockholders, change the business conducted by the credit parties, and enter into hedging agreements. The Credit Facility provides that Coffeyville Resources, LLC may not enter into commodity agreements if, after giving effect thereto, the exposure under all such commodity agreements exceeds 75% of Actual Production (the borrower s estimated future production of refined products based on the actual production for the three prior months) or for a term of longer than six years from December 28, 2006. In addition, the borrower may not enter into material amendments related to any material rights under the Cash Flow Swap, the Partnership s partnership agreement or the management agreements with Goldman, Sachs & Co. and Kelso & Company, L.P., without the prior written approval of the lenders. These limitations are subject to critical exceptions and exclusions and are not designed to protect investors in our common stock.

The Credit Facility also requires the borrower to maintain certain financial ratios as follows:

Fiscal quarter ending	Minimum interest coverage ratio	Maximum leverage ratio
June 30, 2007	2.50:1.00	4.50:1.00
September 30, 2007	2.75:1.00	4.25:1.00
December 31, 2007	2.75:1.00	4.00:1.00
March 31, 2008	3.25:1.00	3.25:1.00
June 30, 2008	3.25:1.00	3.00:1.00
September 30, 2008	3.25:1.00	2.75:1.00
December 31, 2008	3.25:1.00	2.50:1.00
March 31, 2009 and thereafter	3.75:1.00	2.25:1.00 to December 31, 2009, 2.00:1.00 thereafter

The computation of these ratios is governed by the specific terms of the Credit Facility and may not be comparable to other similarly titled measures computed for other purposes or by other companies. The minimum interest coverage ratio is the ratio of consolidated adjusted EBITDA to consolidated cash interest expense over a four quarter period. The maximum leverage ratio is the ratio of consolidated total debt to consolidated adjusted EBITDA over a four quarter period. The computation of these ratios requires a calculation of consolidated adjusted EBITDA. In general, under the terms of our Credit Facility, consolidated adjusted EBITDA is calculated by adding consolidated net income, consolidated interest expense, income taxes, depreciation and amortization, other non-cash expenses, any fees and expenses related to permitted acquisitions, any non-recurring expenses incurred in connection with the issuance of debt or equity, management fees, any unusual or non-recurring charges up to 7.5% of consolidated adjusted EBITDA, any net after-tax loss from disposed or discontinued operations, any incremental property taxes related to abatement non-renewal, any losses attributable to minority equity interests and major scheduled turnaround expenses. As of June 30, 2007, we were in compliance with our covenants under the Credit Facility.

We present consolidated adjusted EBITDA because it is a material component of material covenants within our current Credit Facility and significantly impacts our liquidity and ability to borrow under our revolving line of credit. However, consolidated adjusted EBITDA is not a defined term under GAAP and should not be considered as an alternative to operating income or net income as a measure of operating results or as an alternative to cash flows as a measure of liquidity. Consolidated adjusted EBITDA is calculated under the Credit Facility as follows:

	Original Predecessor	Original Predecessor and Immediate Predecessor Combined (non-GAAP)	Immediate Predecessor and Successor Combined (non-GAAP)	Successor	Successor	Successor
		Year Ended December 31,			Six Months Ended June 30,	
Consolidated Financial Results	**2003**	**2004 (unaudited)**	**2005 (unaudited)**	**2006**	**2006 (unaudited)**	**2007 (unaudited)**
		(in millions)				
Net income (loss)	$ 27.9	$ 60.9	$ (66.8)	$ 191.6	$ 41.8	$ (54.3)
Plus:						
Depreciation and amortization	3.3	2.8	25.1	51.0	24.0	32.2
Interest expense	1.3	10.1	32.8	43.9	22.3	27.6
Income tax expense (benefit)		33.8	(26.9)	119.8	25.7	(141.0)
Impairment of property, plant and equipment	9.6					
Loss on extinguishment of debt		7.2	8.1	23.4		
Inventory fair market value adjustment		3.0	16.6			
Funded letters of credit expenses and interest rate swap not included in interest expense			2.3		0.6	0.2
Major scheduled turnaround expense		1.8		6.6	0.3	76.8
Loss on termination of Swap			25.0			
Unrealized (gain) or loss on derivatives			229.8	(128.5)	92.1	190.0
Non-cash compensation expense for equity awards		1.1	1.8	16.9	2.3	6.8
(Gain) or loss on disposition of fixed assets				1.2	0.4	1.2
Expenses related to acquisition			3.5			

Minority interest in subsidiaries						(0.2)
Management fees		0.5	2.3	2.3	1.0	1.1
Consolidated adjusted EBITDA	$ 42.1	$ 121.2	$ 253.6	$ 328.2	$ 210.5	$ 140.4

In addition to the financial covenants summarized in the table above, the Credit Facility restricts the capital expenditures of Coffeyville Resources, LLC to $375 million in 2007, $125 million in 2008, $125 million in 2009, $80 million in 2010, and $50 million in 2011 and thereafter. The capital expenditures covenant includes a mechanism for carrying over the excess of any previous year s capital expenditure limit. The capital expenditures limitation will not apply for any fiscal year commencing with fiscal 2009 if the borrower consummates an initial public offering and obtains a total leverage ratio of less than or equal to 1.25:1.00 for any quarter commencing with the quarter ended December 31, 2008. We believe the limitations on our capital expenditures imposed by the Credit Facility should allow us to meet our current capital expenditure needs. However, if future events require us or make it beneficial for us to make capital expenditures beyond those currently planned, we would need to obtain consent from the lenders under our Credit Facility.

The Credit Facility also contains customary events of default. The events of default include the failure to pay interest and principal when due, including fees and any other amounts owed under the Credit Facility, a breach of certain covenants under the Credit Facility, a breach of any representation or warranty contained in the Credit Facility, any default under any of the documents entered into in connection with the Credit Facility, the failure to pay principal or interest or any other amount payable under other debt arrangements in an aggregate amount of at least $20 million, a breach or default with respect to material terms under other debt arrangements in an aggregate amount of at least $20 million which results in the debt becoming payable or declared due and payable before its stated maturity, a breach or default under the Cash Flow Swap that would permit the holder or holders to terminate the Cash Flow Swap, events of bankruptcy, judgments and attachments exceeding $20 million, events relating to employee benefit plans resulting in liability in excess of $20 million, a change in control, the guarantees, collateral documents or the Credit Facility failing to be in full force and effect or being declared null and void, any guarantor repudiating its obligations, the failure of the collateral agent under the Credit Facility to have a lien on any material portion of the collateral, and any party under the Credit Facility (other than the agent or lenders under the Credit Facility) contesting the validity or enforceability of the Credit Facility.

Under the terms of our Credit Facility, this offering will be deemed a Qualified IPO. Because this offering is a Qualified IPO, the interest margin on LIBOR loans may in the future decrease from 3.25% to 2.75% (if we have credit ratings of B2/B) or 2.50% (if we have credit ratings of B1/B+). Interest on base rate loans will similarly be adjusted. In addition, because the offering is a Qualified IPO and assuming our other credit facilities are either terminated or amended to allow the following, (1) we will be allowed to borrow an additional $225 million under the Credit Facility after June 30, 2008 to finance capital enhancement projects if we are in pro forma compliance with the financial covenants in the Credit Facility and the rating agencies confirm our ratings, (2) we will be allowed to pay an additional $35 million of dividends each year, if our corporate family ratings are at least B2 from Moody s and B from S&P, (3) we will not be subject to any capital expenditures limitations commencing with fiscal 2009 if our total leverage ratio is less than or equal to 1.25:1 for any quarter commencing with the quarter ended December 31, 2008, and (4) at any time after March 31, 2008 we will be allowed to reduce the Cash Flow Swap to not less than 35,000 barrels a day for fiscal 2008 and terminate the Cash Flow Swap for any year commencing with fiscal 2009, so long as our total leverage ratio is less than or equal to 1.25:1 and we have a corporate family rating of at least B2 from Moody s and B from S&P.

The Credit Facility is subject to an intercreditor agreement among the lenders and the Cash Flow Swap provider, which deal with, among other things, priority of liens, payments and proceeds of sale of collateral.

At December 31, 2006 and June 30, 2007, funded long-term debt, including current maturities, totaled $775.0 million and $773.1 million, respectively, of tranche D term loans. Other commitments at December 31, 2006 and June 30, 2007 included a $150.0 million funded letter of credit facility and a $150.0 million revolving credit facility. As of December 31, 2006, the commitment outstanding on the revolving credit facility was a $6.4 million letter of credit issued to provide transitional collateral to the lender that issued $3.2 million in letters of credit in support of certain environmental obligations and $3.2 million in letters of credit to secure transportation services for a crude oil pipeline. As of June 30, 2007, the commitment outstanding on the revolving credit facility was $73.8 million, including $40.0 million in borrowings, $3.2 million in letters of credit in support of certain environmental obligations and $30.6 million in letters of credit to secure transportation services for a crude oil pipeline.

New Credit Facilities

The flood and crude oil discharge had a significant negative effect on our liquidity in July/August 2007. We did not generate any material revenue while our facilities were shut down due to the flood, but we incurred and continue to incur significant flood repair and cleanup costs, as well as incremental legal, public relations and crisis management costs. We also had significant contractual obligations to purchase gathered crude oil (approximately $35 million per month). We also owed J. Aron approximately $123.7 million under the Cash Flow Swap, which we deferred to January 31, 2008 (see Payment Deferrals Related to Cash Flow Swap below). In addition, although we believe that we

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will recover substantial sums under our insurance policies, we are not sure of the ultimate amount or timing of such recovery.

As a result of these factors, in August 2007 our subsidiaries entered into three new credit facilities. As of September 30, 2007, we had two new $25 million facilities, which were drawn, and one new $75 million facility, which was undrawn.

> ***$25 Million Secured Facility***. Coffeyville Resources, LLC entered into a new $25 million senior secured term loan (the $25 million secured facility). The facility is secured by the same collateral that secures our existing Credit Facility. Interest is payable in cash, at our option, at the base rate plus 1.00% or at the reserve adjusted eurodollar rate plus 2.00%. As of September 30, 2007, $25 million was outstanding under this facility.
>
> ***$25 Million Unsecured Facility***. Coffeyville Resources, LLC entered into a new $25 million senior unsecured term loan (the $25 million unsecured facility). Interest is payable in cash, at our option, at the base rate plus 1.00% or at the reserve adjusted eurodollar rate plus 2.00%. As of September 30, 2007, $25 million was outstanding under this facility.
>
> ***$75 Million Unsecured Facility***. Coffeyville Refining & Marketing Holdings, Inc. entered into a new $75 million senior unsecured term loan (the $75 million unsecured facility). Drawings may be made from time to time in amounts of at least $5 million. Interest accrues, at our option, at the base rate plus 1.50% or at the reserve adjusted eurodollar rate plus 2.50%. Interest is paid by adding such interest to the principal amount of loans outstanding. In addition, a commitment fee equal to 1.00% accrues and is paid by adding such fees to the principal amount of loans outstanding. As of September 30, 2007, $0.0 million was drawn under this facility.

The sole lead arranger and sole bookrunner for each of these facilities is Goldman Sachs Credit Partners L.P. Our obligations under the $25 million secured facility and the $25 million unsecured facility are guaranteed by substantially all of our subsidiaries. The $75 million unsecured facility is guaranteed by Coffeyville Acquisition LLC and, in connection with the consummation of this offering, Coffeyville Acquisition II LLC and CVR Energy will be added as guarantors. After this offering, each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC will guarantee 50% of the aggregate amount of the $75 million unsecured facility. In addition, each of GS Capital Partners V, L.P. and Kelso Investment Associates VII, L.P. guarantees 50% of the aggregate amount of each of the three facilities. Pursuant to the terms of the guarantees, in lieu of the guarantors making payment when due of the guaranteed obligations, GS Capital Partners V, L.P. and Kelso Investment Associates VII, L.P. will have the option to purchase all, but not less than all, of the outstanding obligations at 100% of par value plus accrued interest. The maturity of each of these three facilities is January 31, 2008, provided that if there has been an initial public offering on or prior to January 31, 2008, the maturity will be automatically extended to August 23, 2008.

If loans under the $25 million secured facility and/or the $25 million unsecured facility are outstanding after January 31, 2008, then those facilities will become subject to quarterly amortization in amounts equal to 37.5% of estimated excess cash flow per quarter, provided that these amounts will not be paid under the $25 million secured facility until the $25 million unsecured facility is repaid in full. The proceeds of the $75 million unsecured facility cannot be used to voluntarily prepay the $25 million secured facility or the $25 million unsecured facility.

All three facilities must be repaid with the proceeds of any issuance of equity securities (other than issuances of equity to the Goldman Funds and the Kelso Funds), including the proceeds received in any initial public offering, provided that equity proceeds must be used first to prepay $280 million of term debt under the existing Credit Facility and may be next used to repay up to $50 million of revolver debt under the existing Credit Facility. The $75 million unsecured facility must be repaid with equity proceeds before the $25 million secured facility and the $25 million unsecured facility, and the $25 million unsecured facility must be prepaid with equity proceeds before the

$25 million secured facility. In addition, the $25 million unsecured facility and then the $25 million secured facility must be prepaid with certain insurance proceeds not required to be applied in accordance with the existing Credit Facility.

The covenants in the $25 million secured facility and the $25 million unsecured facility are similar to, but more restrictive than, those in our existing Credit Facility. We may not amend or waive the existing Credit Facility without the prior consent of Goldman Sachs Credit Partners L.P. as arranger under the $25 million facilities. The covenants in the $75 million unsecured facility are also more restrictive than those in our existing credit facility and provide that we may not amend or waive the existing Credit Facility or the $25 million facilities without the consent of Goldman Sachs Credit Partners L.P. as arranger under the $75 million unsecured facility.

Payment Deferrals Related to Cash Flow Swap

As a result of the flood and the temporary cessation of our operations on June 30, 2007, Coffeyville Resources, LLC entered into several deferral agreements with J. Aron with respect to the Cash Flow Swap. These deferral agreements deferred to January 31, 2008 the payment of approximately $123.7 million (plus accrued interest) which we owed to J. Aron. Assuming our initial public offering occurs prior to January 31, 2008, J. Aron agreed to further defer these payments to August 31, 2008 but we will be required to use 37.5% of our consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferred amounts.

On June 26, 2007, Coffeyville Resources, LLC and J. Aron & Company entered into a letter agreement in which J. Aron deferred to August 7, 2007 a $45 million payment which we owed to J. Aron under the Cash Flow Swap for the period ending June 30, 2007. We agreed to pay interest on the deferred amount at the rate of LIBOR plus 3.25%.

On July 11, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to July 25, 2007 a separate $43.7 million payment which we owed to J. Aron under the Cash Flow Swap for the period ending June 30, 2007. J. Aron deferred the $43.7 million payment on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one half of the payment and (b) interest accrued on the $43.7 million from July 9, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On July 26, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to September 7, 2007 both the $45 million payment due August 7, 2007 (and accrued interest) and the $43.7 million payment due July 25, 2007 (and accrued interest). J. Aron deferred these payments on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one half of the payments and (b) interest accrued on the amounts from July 26, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On August 23, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to January 31, 2008 the $45 million payment due September 7, 2007 (and accrued interest), the $43.7 million payment due September 7, 2007 (and accrued interest) and the $35 million payment which we owed to J. Aron under the Cash Flow Swap to settle hedged volume through August 15, 2007. J. Aron deferred these payments (totaling $123.7 million plus accrued interest) on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one half of the payments and (b) interest accrued on the amounts to the date of payment at the rate of LIBOR plus 1.50%. The letter agreement also amended the Cash Flow Swap to incorporate by reference the negative and financial covenants contained in Coffeyville Resources, LLC s new $25 million senior secured credit agreement entered into in August 2007.

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Nitrogen Fertilizer Limited Partnership

We have amended our existing Credit Facility in order to permit the transfer of our nitrogen fertilizer business to the Partnership and the sale of the managing general partner in the Partnership to a new entity owned by our controlling stockholders and senior management. In connection with this amendment, the Partnership and CVR Special GP, LLC (the subsidiary through which we own our general partner interest in the Partnership) were added as guarantors and collateral grantors under the Credit Facility. In addition, the amendment provided that we may not enter into material amendments related to any material rights under the Partnership s partnership agreement without the prior written approval of the lenders.

The managing general partner of the Partnership may, from time to time, seek to raise capital through a public or private offering of limited partner interests in the Partnership. Any decision to pursue such a transaction would be made in the discretion of the managing general partner, not us, and any proceeds raised in a primary offering would be for the benefit of the Partnership, not us (although in some cases, depending on the structure of the transaction, the Partnership might remit proceeds to us). If the managing general partner elects to pursue a public or private offering of limited partner interests in the Partnership, we expect that any such transaction would require amendments to our credit facilities, as well as the Cash Flow Swap, in order to remove the Partnership and its subsidiaries as obligors under such instruments. Any such amendments could result in significant changes to our credit facilities pricing, mandatory repayment provisions, covenants and other terms and could result in increased interest costs and require payment by us of additional fees. We have agreed to use our commercially reasonable efforts to obtain such amendments if the managing general partner elects to cause the Partnership to pursue a public or private offering and gives us at least 90 days written notice. However, we cannot assure you that we will be able to obtain any such amendment on terms acceptable to us or at all. If we are not able to amend our credit facilities on terms satisfactory to us, we may need to refinance them with other facilities. We will not be considered to have used our commercially reasonable efforts to obtain such amendments if we do not effect the requested modifications due to (i) payment of fees to the lenders or the swap counterparty, (ii) the costs of this type of amendment, (iii) an increase in applicable margins or spreads or (iv) changes to the terms required by the lenders including covenants, events of default and repayment and prepayment provisions; provided that (i), (ii), (iii) and (iv) in the aggregate are not likely to have a material adverse effect on us. In order to effect the requested amendments, we may require that (1) the Partnership s initial public or private offering generate at least $140 million in net proceeds to us and (2) the Partnership raise an amount of cash (from the issuance of equity or incurrence of indebtedness) equal to $75 million minus the amount of capital expenditures it will reimburse us for from the proceeds of its initial public or private offering (as described in The Nitrogen Fertilizer Limited Partnership Formation Transactions) and to distribute that cash to us prior to, or concurrently with, the closing of its initial public or private offering. If the managing general partner sells interests to third party investors, we expect that the Partnership may at such time seek to enter into its own credit facility. See The Nitrogen Fertilizer Limited Partnership.

In addition, we may elect to sell our interests in the Partnership in a secondary public offering (either in connection with a public offering by the Partnership, but subject to priority rights in favor of the Partnership, or following completion of the Partnership s initial public offering, if any) or in a private placement. Neither the consent of the managing general partner nor the consent of the Partnership is required for any sale of our interests in the Partnership, other than customary blackout periods relating to offerings by the Partnership. Any proceeds raised would be for our benefit. The Partnership has granted us registration rights which will require the Partnership to register our interests with the SEC at our request from time to time (following any public offering by the Partnership), subject to various limitations and requirements.

Capital Spending

We divide our capital spending needs into two categories: non-discretionary, which is either capitalized or expensed, and discretionary, which is capitalized. Non-discretionary capital spending,

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such as for planned turnarounds and other maintenance, is required to maintain safe and reliable operations or to comply with environmental, health and safety regulations. The total non-discretionary capital spending needs for our refinery business and the nitrogen fertilizer business, including major scheduled turnaround expenses, were approximately $170 million in 2006 and we estimate that the total non-discretionary capital spending needs of our refinery business and the nitrogen fertilizer business will be approximately $230 million in 2007 and approximately $258 million in the aggregate over the three-year period beginning 2008. These estimates include, among other items, the capital costs necessary to comply with environmental regulations, including Tier II gasoline standards and on-road diesel regulations. As described above, our credit facilities limit the amount we can spend on capital expenditures.

Compliance with the Tier II gasoline and on-road diesel standards required us to spend approximately $133 million during 2006 and we estimate that compliance will require us to spend approximately $108 million during 2007 and approximately $57 million in the aggregate between 2008 and 2010. These amounts are reflected in the table below under Environmental capital needs. See Business Environmental Matters Fuel Regulations Tier II, Low Sulfur Fuels.

The following table sets forth our estimate of non-discretionary spending for our refinery business and the nitrogen fertilizer business for the years presented as of June 30, 2007 (other than 2006 which reflects actual spending). After consummation of this offering, capital spending for the fertilizer business will be determined by the managing general partner of the Partnership. The data contained in the table below represents our current plans, but these plans may change as a result of unforeseen circumstances and we may revise these estimates from time to time or not spend the amounts in the manner allocated below.

Petroleum Business

	2006	2007	2008	2009	2010	2011	2012	Cumulative
				(in millions)				
Environmental capital needs	$ 144.6	$ 128.2	$ 28.2	$ 39.8	$ 42.2	$ 2.6	$ 2.1	$ 387.7
Sustaining capital needs	11.8	21.2	24.4	22.0	22.0	22.0	22.0	145.4
	156.4	149.4	52.6	61.8	64.2	24.6	24.1	533.1
Major scheduled turnaround expenses	4.0	77.0			50.0			131.0
Total estimated non-discretionary spending	$ 160.4	$ 226.4	$ 52.6	$ 61.8	$ 114.2	24.6	24.1	$ 664.1

Nitrogen Business

	2006	2007	2008	2009	2010	2011	2012	Cumulative
				(in millions)				
Environmental capital needs	$ 0.1	$ 0.7	$ 3.3	$ 2.9	$ 2.6	2.7	3.8	$ 16.1
Sustaining capital needs	6.6	2.9	7.1	3.7	4.5	4.8	4.3	33.9

	6.7	3.6	10.4	6.6	7.1	7.5	8.1	50.0
Major scheduled turnaround expenses	2.6		2.3		2.6		2.8	10.3
Total estimated non-discretionary spending	$ 9.3	$ 3.6	$ 12.7	$ 6.6	$ 9.7	$ 7.5	$ 10.9	$ 60.3

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Combined

	2006	2007	2008	2009	2010	2011	2012	Cumulative
			(in millions)					
Environmental capital needs	$ 144.7	$ 128.9	$ 31.5	$ 42.7	$ 44.8	5.3	5.9	$ 403.8
Sustaining capital needs	18.4	24.1	31.5	25.7	26.5	26.8	26.3	179.3
	163.1	153.0	63.0	68.4	71.3	32.1	32.2	583.1
Major scheduled turnaround expenses	6.6	77.0	2.3		52.6		2.8	141.3
Total estimated non-discretionary spending	$ 169.7	$ 230.0	$ 65.3	$ 68.4	$ 123.9	32.1	35.0	$ 724.4

We undertake discretionary capital spending based on the expected return on incremental capital employed. Discretionary capital projects generally involve an expansion of existing capacity, improvement in product yields, and/or a reduction in direct operating expenses. As of June 30, 2007, we had committed approximately $9.0 million towards discretionary capital spending in 2007. Other than the fertilizer plant expansion project referred to below, we anticipate that our discretionary capital spending will not exceed approximately $30 million per year between 2008 and 2012.

The Partnership is also considering a $50 million fertilizer plant expansion, which we estimate could increase the nitrogen fertilizer plant s capacity to upgrade ammonia into premium priced UAN by 50% to approximately 1,000,000 tons per year. This project would also improve the cost structure of the nitrogen fertilizer business by eliminating the need for rail shipments of ammonia, thereby avoiding anticipated cost increases in such transport.

Cash Flows

Comparability of cash flows from operating activities for the years ended December 31, 2006, 2005, 2004 and 2003 has been impacted by the Initial Acquisition and the Subsequent Acquisition. See Factors Affecting Comparability. Therefore, we have presented our discussion of cash flows from operations by comparing (1) the six months ended June 30, 2007 and 2006, (2) the year ended December 31, 2006 with the 174 days ended September 23, 2005 and the 233 days ended December 31, 2005, (3) the 233 days ended December 31, 2005, the 174 days ended September 23, 2005, the 304 days ended December 31, 2004 and the 62 days ended March 2, 2004 and (4) the year ended December 31, 2003, the 62 days ended March 2, 2004, and the 304 days ended December 31, 2004.

In addition to the cash flows discussed below, following this offering we will initially be entitled to all cash distributed by the Partnership. However, the amount of cash flows from the Partnership that we will receive in the future may be limited by a number of factors. The Partnership may enter into its own credit facility or other contracts that limit its ability to make distributions to us. Additionally, in the future Fertilizer GP will receive a greater allocation of distributions as more cash becomes available for distribution, and consequently we will receive a smaller percentage of quarterly distributions over time. Our rights to distributions may also be adversely affected if the Partnership issues equity in the future. See Risk Factors Risks Related to the Limited Partnership Structure Through Which We Will Hold Our Interest in the Nitrogen Fertilizer Business Our rights to receive distributions from the Partnership may be limited over time and Risk Factors Risks Related to the Limited Partnership Structure Through

Which We Will Hold Our Interest in the Nitrogen Fertilizer Business The Partnership may not have sufficient available cash to enable it to make the quarterly distributions to us following establishment of cash reserves and payment of fees and expenses.

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Operating Activities

Comparison of the Six Months Ended June 30, 2007 and the Six Months Ended June 30, 2006.

Net cash flows from operating activities for the six months ended June 30, 2007 was $157.6 million. The positive cash flow from operating activities generated over this period was primarily driven by favorable changes in other working capital and trade working capital, partially offset by unfavorable changes in other assets and liabilities over the period. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. See Consolidated Results of Operations Six Months Ended June 30, 2007 Compared to the Six Months Ended June 30, 2006. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net loss for the six months ended June 30, 2007 included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of June 30, 2007 (approximately two years and nine months) and the NYMEX crack spread that is the basis for the underlying swaps had increased, the unrealized losses on the Cash Flow Swap significantly decreased our Net Income over this period. The impact of these unrealized losses on the Cash Flow Swap is apparent in the $276.6 million increase in the payable to swap counterparty. Adding to our operating cash flow for the six months ended June 30, 2007 was a $5.4 million source of cash related to a decrease in trade working capital. For the six months ended June 30, 2007, accounts receivable increased $6.4 million while inventory increased by $17.8 million resulting in a net use of cash of $24.2 million. These uses of cash due to changes in trade working capital were more than offset by an increase in accounts payable, or a source of cash, of $29.6 million. The primary uses of cash during the period include a $4.6 million increase in prepaid expenses and other current assets and a $11.1 million accrual for deferred income taxes primarily as a result of accelerated depreciation related to the expansion and a $101.4 million accrual of current income taxes receivable related to the current income tax benefit generated upon the loss through June 30, 2007 as well as significant income tax credits being generated for production of ultra low sulfur diesel fuel.

Net cash flows provided by operating activities for the six months ended June 30, 2006 was $120.3 million. The positive cash flow from operating activities during this period was primarily the result of strong operating earnings and favorable changes in other working capital during the period partially offset by unfavorable changes in trade working capital and other assets and liabilities. Net income for the period was not indicative of the operating margins for the period. This was the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. See Consolidated Results of Operations Six Months Ended June 30, 2007 Compared to the Six Months Ended June 30, 2006. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net income for the six months ended June 30, 2006 included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of June 30, 2006 (approximately four years) and the NYMEX crack spread that is the basis for the underlying swaps had increased during the period, the unrealized losses on the Cash Flow Swap decreased our Net Income over this period. The impact of these unrealized gains on the Cash Flow Swap is apparent in the $112.2 million increase in the payable to swap counterparty. Trade working capital resulted in a use of cash of $20.6 million in cash during the six months ended June 30, 2006 as the decrease in accounts receivable of $8.0 million was more than offset by increases in inventory of $25.4 million and a decrease in accounts payable of $3.2 million.

Comparison of Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005.

Comparability of cash flows from operating activities for the year ended December 31, 2006 and the year ended December 31, 2005 has been impacted by the Initial Acquisition and the Subsequent Acquisition. See Factors Affecting Comparability. For instance, completion of the Subsequent Acquisition by Successor required a mark up of purchased inventory to fair market value at the closing of the transaction on June 24, 2005. This had the effect of reducing overall cash flow for Successor as it capitalized that portion of the purchase price of the assets into cost of product sold. Therefore, the discussion of cash flows from operations has been broken down into three separate periods: the year ended December 31, 2006, the 174 days ended June 23, 2005 and the 233 days ended December 31, 2005.

Net cash flows from operating activities for the year ended December 31, 2006 was $186.6 million. The positive cash flow from operating activities generated over this period was primarily driven by our strong operating environment and favorable changes in other assets and liabilities, partially offset by unfavorable changes in trade working capital and other working capital over the period. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. See Results of Operations Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net income for the year ended December 31, 2006 included both the realized losses and the unrealized gains on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of December 31, 2006 (approximately three years and six months) and the NYMEX crack spread that is the basis for the underlying swaps had declined, the unrealized gains on the Cash Flow Swap significantly increased our net income over this period. The impact of these unrealized gains on the Cash Flow Swap is apparent in the $147.0 million decrease in the payable to swap counterparty. Reducing our operating cash flow for the year ended December 31, 2006 was a $0.3 million use of cash related to an increase in trade working capital. For the year ended December 31, 2006, accounts receivable decreased approximately $1.9 million while inventory increased $7.2 million and accounts payable increased $5.0 million. Other primary uses of cash during the period include a $5.4 million increase in prepaid expenses and other current assets and a $37.0 million reduction in accrued income taxes. Offsetting these uses of cash was an $86.8 million increase in deferred income taxes primarily the result of the unrealized gain on the Cash Flow Swap and a $15.3 million increase in other current liabilities.

Net cash flows from operating activities for the 174 days ended June 23, 2005 was $12.7 million. The positive cash flow generated over this period was primarily driven by income of $52.4 million, offset by a $54.3 million increase in trade working capital. During this period, accounts receivable and inventory increased $11.3 million and $59.0 million, respectively. These uses of cash were primarily the result of our expansion into the rack marketing business, which offered increased accounts receivable credit terms relative to bulk refined product sales, an increase in product sales prices and an increase in overall inventory levels.

Net cash flows provided by operating activities for the 233 days ended December 31, 2005 was $82.5 million. The positive cash flow from operating activities generated over this period was primarily the result of strong operating earnings during the period partially offset by the expensing of a $25.0 million option entered into by Successor for the purpose of hedging certain levels of refined product margins and the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. At the closing of the Subsequent Acquisition, we determined that this option was

not economical and we allowed the option to expire worthless and thus resulted in the expensing of the associated premium. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk and Results of Operations Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net income for the year ended December 31, 2005 included the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap became effective July 1, 2005 and had an original term of approximately five years and the NYMEX crack spread that is the basis for the underlying swaps had improved since the trade date of the Cash Flow Swap on June 16, 2005, the unrealized losses on the Cash Flow Swap significantly reduced our net income over this period. The impact of these unrealized losses on all derivatives, including the Cash Flow Swap, is apparent in the $256.7 million increase in the payable to swap counterparty. Additionally and as a result of the closing of the Subsequent Acquisition, Successor marked up the value of purchased inventory to fair market value at the closing of the transaction on June 24, 2005. This had the effect of reducing overall cash flow for Successor as it capitalized that portion of the purchase price of the assets into cost of product sold. The total impact of this for the 233 days ended December 31, 2005 was $14.3 million. Trade working capital provided $8.0 million in cash during the 233 days ended December 31, 2005 as an increase in accounts receivable was more than offset by decreases in inventory and an increase in accounts payable. Offsetting the sources of cash from operating activities highlighted above was a $98.4 million use of cash related to deferred income taxes and a $4.7 million use of cash related to other long-term assets.

Comparison of the 233 Days Ended December 31, 2005, the 174 Days Ended June 23, 2005, the 304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004.

Comparability of cash flows from operating activities for the year ended December 31, 2005 to the year ended December 31, 2004 has been impacted by the Initial Acquisition and the Subsequent Acquisition. See Factors Affecting Comparability. Immediate Predecessor did not assume the accounts receivable or the accounts payable of Farmland. As a result, Farmland collected and made payments on these accounts after March 3, 2004 and these transactions are not included on our consolidated statements of cash flows. In addition, Coffeyville Acquisition LLC s acquisition of the subsidiaries of Coffeyville Group Holdings, LLC required a mark up of purchased inventory to fair market value at the closing of the Initial Acquisition on June 24, 2005. This had the effect of reducing overall cash flow for Coffeyville Acquisition LLC as it capitalized that portion of the purchase price of the assets into cost of product sold. Therefore, the discussion of cash flows from operations has been broken down into four separate periods: the 233 days ended December 31, 2005, the 174 days ended June 23, 2005, the 304 days ended December 31, 2004 and the 62 days ended March 2, 2004.

Net cash flows provided by operating activities for the 233 days ended December 31, 2005 was $82.5 million. The positive cash flow from operating activities generated over this period was primarily driven by our strong operating environment and favorable changes in other working capital over the period. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. The net income for the period was not indicative of the excellent operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. See Consolidated Results of Operations 233 Days Ended December 31, 2005 and the 174 Days Ended June 23, 2005 Compared to the 304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Therefore, the net income for the 233 days ended December 31, 2005 included both the realized and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of December 31, 2005 (approximately four and one-half years) and the NYMEX crack spread that is the basis for the underlying swaps had improved substantially, the unrealized losses on the Cash Flow Swap significantly reduced our Net Income over this period. The impact of these unrealized losses on all derivatives, including the Cash Flow Swap, is apparent in the $256.7 million unrealized loss in the period related to the increase in the payable to swap counterparty. Contributing to the sources of cash for operating activities during the period was a decrease of trade working capital of $8.0 million and an increase in both deferred revenue and other current liabilities of $10.0 million and $10.5 million, respectively. Primary uses of cash during the period were related to increases in prepaid expenses and other current assets of $6.5 million due to increases in insurance and other prepaids and an increase in deferred income taxes associated with purchase price accounting for the transaction of $98.4 million.

Net cash flows for operating activities for the 174 days ended June 23, 2005 was $12.7 million. The positive cash flow generated over this period was primarily driven by income of $52.4 million, offset by a $54.3 million increase in trade working capital. During this period, accounts receivable and inventory increased $11.3 million and $59.0 million, respectively. These uses of cash were primarily the result of our expansion into the rack marketing business, which offered increased accounts receivable credit terms relative to bulk refined product sales, an increase in product sales prices and an increase in overall inventory levels.

Net cash flow from operating activities for the 304 days ended December 31, 2004 was $89.8 million. The primary driver for the positive cash flow from operations over this period was cash earnings and favorable changes in trade working capital. During this period, we experienced favorable market conditions in our petroleum business and the nitrogen fertilizer business. Changes in trade working capital produced cash flow of approximately $27.6 million during this period. For the 304 days ended December 31, 2004, we experienced a $20.1 million decrease in inventory due to an effort to reduce inventory carrying levels and a $31.1 million increase in accounts payable due to the extension of credit terms by several crude oil vendors and a large electricity vendor. These positive cash flows from operations were partially offset by an increase in accounts receivable of $23.6 million as Immediate Predecessor assumed ownership of the business from Farmland. In addition, changes in other working capital generated approximately $8.7 million in cash during the period. This was primarily the result of increases in other current liabilities by $13.0 million as a result of accruals for personnel, taxes other than income taxes, leases, freight and professional services, offset by reductions in certain prepaid expenses and other current assets.

Net cash from operating activities for the 62 days ended March 2, 2004 was $53.2 million. The positive cash flow generated over this period was primarily driven by cash earnings and favorable changes in other working capital of $34.4 million. With respect to other working capital, $25.7 million in cash resulted from reductions in prepaid expenses and other current assets due to the reduction in prepaid crude oil required by Farmland due to the Initial Acquisition by Coffeyville Group Holdings, LLC and $8.3 million of deferred revenue resulting primarily from prepaid fertilizer contract activity of the nitrogen fertilizer operations. The $6.5 million of cash flows generated from trade working capital was mainly the result of a $19.6 million decrease in accounts receivable due to the collection of a large petroleum account, which had been past due.

Comparison of the Year Ended December 31, 2003, the 62 Days Ended March 2, 2004 and the 304 Days Ended December 31, 2004.

Comparability of cash flows from operating activities for the year ended December 31, 2004 to 2003 has been impacted by the closing of the Initial Acquisition on March 3, 2004. We did not assume the accounts receivable or the accounts payable of Farmland. As a result, Farmland collected and made payments on these accounts after March 3, 2004 and these transactions are not included on our consolidated statements of cash flows. Therefore, this discussion of the cash flow from operations

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has been separated into three periods: the year ended December 31, 2003, the 62 days ended March 2, 2004 and the 304 days ended December 31, 2004.

Net cash flow from operating activities for the 304 days ended December 31, 2004 was $89.8 million. The primary driver for the positive cash flow from operations over this period was cash earnings and favorable changes in trade working capital. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. During this period, we experienced favorable market conditions in our petroleum business and the nitrogen fertilizer business. Changes in trade working capital produced cash flow of approximately $27.6 million during this period. For the 304 days ended December 31, 2004, we experienced a $20.1 million decrease in inventory due to an effort to reduce inventory carrying levels and a $31.1 million increase in accounts payable due to the extension of credit terms by several crude oil vendors and a large electricity vendor. These positive cash flows from operations were partially offset by an increase in accounts receivable of $23.6 million as Immediate Predecessor assumed ownership of the business from Farmland. In addition, changes in other working capital generated approximately $8.7 million in cash during the period. This was primarily the result of increases in other current liabilities by $13.0 million as a result of accruals for personnel, taxes other than income taxes, leases, freight and professional services, offset by reductions in certain prepaid expenses and other current assets.

Net cash flow from operating activities for the 62 days ended March 2, 2004 was $53.2 million. The positive cash flow generated over this period was primarily driven by cash earnings and favorable changes in other working capital of $34.4 million. With respect to other working capital, $25.7 million in cash resulted from reductions in prepaid expenses and other current assets due to the reduction in prepaid crude oil required by Farmland due to the Initial Acquisition by Coffeyville Group Holdings, LLC and $8.3 million of deferred revenue resulting primarily from prepaid fertilizer contract activity of the nitrogen fertilizer operations. The $6.5 million of cash flows generated from trade working capital was mainly the result of a $19.6 million decrease in accounts receivable due to the collection of a large petroleum account, which had been past due.

Net cash flow from operating activities for the year ended December 31, 2003 was $20.3 million. The positive cash flow from operations over this period was directly attributable to cash earnings offset by unfavorable changes in trade and other working capital. The positive cash earnings were the result of an improvement in the environment for both our petroleum business and the nitrogen fertilizer business versus the prior period. The $6.6 million cash outflow resulting from changes in trade working capital was primarily attributable to a $25.3 million increase in accounts receivable due to the delinquency of a large petroleum customer. This increase in accounts receivable was partially offset by a reduction in inventory by $10.4 million and an $8.3 million increase in accounts payable. The increase in other working capital of $21.8 million was primarily driven by a $23.8 million increase in prepaid expenses and other current assets directly attributable to the necessity for Farmland to prepay its crude oil supply during its bankruptcy.

Investing Activities

Comparison of the Six Months Ended June 30, 2007 and the Six Months Ended June 30, 2006.

Net cash used in investing activities for the six months ended June 30, 2007 was $214.1 million compared to $86.2 million for the six months ended June 30, 2006. The increase in investing activities for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006 was the result of increased capital expenditures associated with various capital projects in our Petroleum business.

Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005.

Net cash used in investing activities for the year ended December 31, 2006 was $240.2 million compared to $12.3 million for the 174 days ended June 23, 2005 and $730.3 million for the 233 days ended December 31, 2005. Investing activities for the year ended December 31, 2006 was the result of a capital spending increase associated with Tier II fuel compliance and other capital expenditures. Investing activities for the combined period ended December 31, 2005 included $685.1 million related to the Subsequent Acquisition. The other primary use of cash for investing activities for the year ended December 31, 2005 was approximately $57.4 million in capital expenditures.

233 Days Ended December 31, 2005 and the 174 Days Ended June 23, 2005 Compared to the 304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004.

Net cash used in investing activities was $730.3 million for the 233 days ended December 31, 2005 and $12.3 million for the 174 days ended June 23, 2005 as compared to $130.8 million for the 304 days ended December 31, 2004 and $0 for the 62 days ended March 2, 2004. For the combined years ended December 31, 2005 and December 31, 2004, net cash used in investing activities was $742.6 million as compared to $130.8 million. Both periods included acquisition costs associated with successive owners of the assets. Investing activities for the year ended December 31, 2005 included the $685.1 million related to the Subsequent Acquisition. Investing activities for the year ended December 31, 2004 included the $116.6 million acquisition of our assets by Immediate Predecessor from Original Predecessor on March 3, 2004. The other primary use of cash for investing activities was $57.4 million for capital expenditures in 2005 as compared to $14.2 million for 2004. This increase in capital expenditures was primarily the result of a capital spending increase associated with Tier II fuel compliance and other capital expenditures.

304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004 Compared to Year Ended December 31, 2003.

Net cash used in investing activities for the 304 days ended December 31, 2004 was $130.8 million and $0 for the 62 days ended March 2, 2004 as compared to $0.8 million in 2003. This difference in the combined periods for the year ended December 31, 2004 and the year ended December 31, 2003 of $130.0 million is directly attributable to an increase in capital expenditures and the acquisition of the Farmland assets during the comparable periods. Throughout its bankruptcy, Farmland maintained capital expenditures for its petroleum and nitrogen assets at a minimum.

Financing Activities

Comparison of the Six Months Ended June 30, 2007 and the Six Months Ended June 30, 2006.

Net cash provided by financing activities for the six months ended June 30, 2007 was $37.6 million as compared to net cash provided by financing activities of $29.0 million for the six months ended June 30, 2006. The primary sources of cash for the six months ended June 30, 2007 were obtained through borrowings under the revolving credit facility. See Liquidity and Capital Resources Debt. During the six months ended June 30, 2007, we also paid $1.9 million of scheduled principal payments. For the six months ended June 30, 2006, the primary sources of cash were the result of a $20.0 million issuance of members equity and $10.0 million of delayed draw term loans both specifically generated to fund a portion of two discretionary capital expenditures at our Petroleum operations. During the six months ended June 30, 2006, we also paid $1.1 million of scheduled principal payments.

Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005.

Net cash provided by financing activities for the twelve months ended December 31, 2006 was $30.8 million as compared to net cash used by financing activities for the 174 days ended June 23, 2005 of $52.4 million and net cash provided by financing activities of $712.5 million for the 233 days ended December 31, 2005. The primary sources of cash for the year ended December 31, 2006 were obtained through a refinancing of the Successor s first and second lien credit facilities into a new long term debt Credit Facility of $1.075 billion, of which $775.0 million was outstanding as of December 31, 2006. See Liquidity and Capital Resources Debt. The $775.0 million term loan under the Credit Facility was used to repay approximately $527.7 million in first and second lien debt outstanding, fund $5.5 million in prepayment penalties associated with the second lien credit facility and fund a $250.0 million cash distribution to Coffeyville Acquisition LLC. Other sources of cash included $20.0 million of additional equity contributions into Coffeyville Acquisition LLC, which was subsequently contributed to our operating subsidiaries, and $30.0 million of additional delayed draw term loans issued under the first lien credit facility. These sources of cash were specifically generated to fund a portion of two discretionary capital expenditures at our petroleum operations. During this period, we also paid $1.7 million of scheduled principal payments on the first lien term loans.

For the combined period ended December 31, 2005, net cash provided by financing activities was $660.0 million. The primary sources of cash for the combined periods ended December 31, 2005 related to the funding of Successor s acquisition of the assets on June 24, 2005 in the form of $500.0 million in long-term debt and $227.7 million of equity. Additional equity of $10.0 million was contributed into Coffeyville Acquisition LLC subsequent to the aforementioned acquisition, which was subsequently contributed to our operating subsidiaries, in order to fund a portion of two discretionary capital expenditures at our refining operations. Additional sources of funds during the year ended December 31, 2005 were obtained through the borrowing of $0.2 million in revolving loan proceeds, net of $69.6 million of repayments. Offsetting these sources of cash from financing activities during the year ended December 31, 2005 were $24.6 million in deferred financing costs associated with the first and second lien debt commitments raised by Successor in connection with the Subsequent Acquisition and a $52.2 million cash distribution to Immediate Predecessor prior to the Subsequent Acquisition. See Liquidity and Capital Resources Debt.

233 Days Ended December 31, 2005 and the 174 Days Ended June 23, 2005 Compared to the 304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004.

Net cash provided by financing activities for the 233 days ended December 31, 2005 was $712.5 million and net cash used by financing activities for the 174 days ended June 23, 2005 was $52.4 million. Net cash provided by financing activities for the 304 days ended December 31, 2004 was $93.6 million and net cash used by financing activities was $53.2 million. For the combined periods ended December 31, 2005 and December 31, 2004, net cash used in financing activities was $660.0 million and $40.4 million, respectively. The primary sources of cash for the combined periods of 2005 related to the funding of Successor s acquisition of the assets on June 24, 2005 in the form of $500.0 million in long-term debt and $227.7 million of equity. Additional equity of $10.0 million was contributed into Coffeyville Acquisition LLC subsequent to the aforementioned acquisition, which was subsequently contributed to our operating subsidiaries, in order to fund a portion of two discretionary capital expenditures at our refining operations. Additional sources of funds during the year ended December 31, 2005 were obtained through the borrowing of $0.2 million in revolving loan proceeds, net of $69.6 million of repayments. Offsetting these sources of cash from financing activities during the year ended December 31, 2005 were $24.7 million in deferred financing costs associated with the first and second lien debt commitments raised

by Coffeyville Acquisition LLC in connection with the Subsequent Acquisition and a $52.2 million cash distribution to the owners of Coffeyville Group Holdings, LLC prior to the Subsequent Acquisition. See Liquidity and Capital Resources Debt.

The uses of cash for financing activities for the combined periods ended December 31, 2004 related primarily to the prepayment of the $23.0 million term loan, a $100.0 million cash distribution to the holders of the preferred and common units issued by Coffeyville Group Holdings, LLC, $1.2 million repayment of a capital lease obligation, $16.3 million in financing costs and $53.2 million in net divisional equity distribution to Farmland. We used cash from operations, a $63.3 million equity contribution related to the Initial Acquisition and a new term loan for $150.0 million completed on May 10, 2004 to finance the aforementioned cash outflows in 2004.

304 Days Ended December 31, 2004 and the 62 Days Ended March 2, 2004 Compared to Year Ended December 31, 2003.

Net cash provided by financing activities for the 304 days ended December 31, 2004 was $93.6 million and net cash used by financing activities was $53.2 million for the 62 days ended March 2, 2004. For the combined period ended December 31, 2004, net cash provided by financing activities in 2004 was $40.4 million. The uses of cash for financing activities for the combined period ended December 31, 2004 related primarily to the prepayment of the $23.0 million term loan, a $100.0 million cash distribution to the holders of the preferred and common units issued by Coffeyville Group Holdings, LLC, $1.2 million repayment of a capital lease obligation, $16.3 million in financing costs and $53.2 million in net divisional equity distribution to Farmland. We used cash from operations, a $63.3 million equity contribution related to the Initial Acquisition and a new term loan for $150.0 million completed on May 10, 2004 to finance the aforementioned cash outflows in 2004. In 2003, we used $19.5 million in cash to fund a net divisional equity distribution.

Prior to the Initial Acquisition, our petroleum business and the nitrogen fertilizer business were organized as divisions within Farmland. As such, these divisions did not have a discreet legal structure from Farmland and the cash flows from these operations were collected and disbursed under Farmland s centralized approach to cash management and the financing of its operations. The net divisional equity distribution characterized on the accompanying financial statements represents the net cash generated by these divisions and funded to Farmland to finance its overall operations.

Capital and Commercial Commitments

In addition to long-term debt, we are required to make payments relating to various types of obligations. The following table summarizes our minimum payments as of June 30, 2007 relating to long-term debt, operating leases, unconditional purchase obligations and other specified capital and commercial commitments for the six months ending December 31, 2007, the four-year period following December 31, 2007 and thereafter.

Our ability to make payments on and to refinance our indebtedness, to fund planned capital expenditures and to satisfy our other capital and commercial commitments will depend on our ability to generate cash flow in the future. This, to a certain extent, is subject to refining spreads, fertilizer margins, receipt of distributions from the Partnership and general economic financial, competitive, legislative, regulatory and other factors that are beyond our control. Based on our current level of operations, we believe our cash flow from operations, available cash and available borrowings under our credit facilities and the proceeds we receive from this offering will be adequate to meet our future liquidity needs for at least the next twelve months.

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	Payments Due by Period						
	Total	Six Months Ending December 31, 2007	2008	2009 (in millions)	2010	2011	Thereafter
Contractual Obligations							
Long-term debt(1)	$ 823.1	$ 3.9	$ 57.7	$ 7.6	$ 7.5	$ 7.4	$ 739.0
Operating leases(2)	11.1	1.7	3.9	2.9	1.6	0.9	0.1
Unconditional purchase obligations(3)	516.9	13.0	21.1	21.1	46.2	44.3	371.2
Environmental liabilities(4)	9.7	1.0	1.0	0.9	0.6	0.3	5.9
Funded letter of credit fees(5)	15.9	2.7	5.3	5.3	2.6		
Interest payments(6)	407.3	35.4	69.8	66.0	65.3	64.6	106.2
Total	$ 1,784.0	$ 57.7	$ 158.8	$ 103.8	$ 123.8	$ 117.5	$ 1,222.4
Other Commercial Commitments							
Standby letters of credit(7)	$ 33.8	$ 33.8	$	$	$	$	$

(1) Long-term debt amortization is based on the contractual terms of our Credit Facility. We may be required to amend our Credit Facility in connection with an offering by the Partnership. Subsequent to June 30, 2007, we entered into three additional credit facilities totaling $125 million. As of September 30, 2007, $50 million was outstanding under these new facilities. See Description of Our Indebtedness and the Cash Flow Swap.

(2) The nitrogen fertilizer business leases various facilities and equipment, primarily railcars, under non-cancelable operating leases for various periods.

(3) The amount includes (1) commitments under several agreements in our petroleum operations related to pipeline usage, petroleum products storage and petroleum transportation and (2) commitments under an electric supply agreement with the City of Coffeyville.

(4) Environmental liabilities represents our estimated payments required by federal and/or state environmental agencies related to closure of hazardous waste management units at our sites in Coffeyville and Phillipsburg, Kansas. We also have other environmental liabilities which are not contractual obligations but which would be necessary for our continued operations. See Business Environmental Matters.

(5) This amount represents the total of all fees related to the funded letter of credit issued under our Credit Facility. The funded letter of credit is utilized as credit support for the Cash Flow Swap. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

(6) Interest payments are based on interest rates in effect at June 30, 2007 and assume contractual amortization payments.

(7) Standby letters of credit include our obligations under $3.2 million of letters of credit issued in connection with environmental liabilities and $30.6 million in letters of credit to secure transportation expenses related to the Transportation Services Agreement with CCPS Transportation, LLC.

Our business may not generate sufficient cash flow from operations, and future borrowings may not be available to us under our credit facilities in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may seek to sell additional assets to fund our liquidity needs but may not be able to do so. We may also need to refinance all or a portion of our indebtedness on or before maturity. We may not be able to refinance any of our indebtedness on commercially reasonable terms or at all.

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Recently Issued Accounting Standards

In December 2004, the Financial Accounting Standards Board, or FASB, issued SFAS No. 151, *Inventory Costs*, which clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs, and spoilage. Under SFAS 151, such items will be recognized as current-period charges. In addition, SFAS 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. We adopted SFAS 151 effective January 1, 2006. There was no impact on our financial position or results of operations as a result of adopting this standard.

The Emerging Issues Task Force, or EITF, reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, and the FASB ratified it on September 28, 2005. This Issue addresses accounting matters that arise when one company both sells inventory to and buys inventory from another company in the same line of business, specifically, when it is appropriate to measure purchases and sales of inventory at fair value and record them in cost of sales and revenues, and when they should be recorded as an exchange measured at the book value of the item sold. This Issue is to be applied to new arrangements entered into in reporting periods beginning after March 15, 2006. There was no significant impact on our financial position or results of operations as a result of adoption of this Issue.

In June 2006, the FASB ratified its consensus on EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement.* EITF 06-3 includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include sales, use, value added, and some excise taxes. These taxes should be presented on either a gross or net basis, and if reported on a gross basis, a company should disclose amounts on those taxes in interim and annual financial statements for each period for which an income statement is presented. The guidance in EITF 06-3 is effective for all periods beginning after December 15, 2006 and is not expected to significantly affect our financial position or results of operations.

In June 2006, the FASB issued Interpretation (FIN) No. 48, *Accounting for Uncertain Tax Positions an interpretation of FASB Statement No. 109.* FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*, by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. If a tax position is more likely than not to be sustained upon examination, then an enterprise would be required to recognize in its financial statements the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosures and transition. The application of FIN No. 48 is effective for fiscal years beginning after December 15, 2006 and is not expected to have a material impact on our financial position or results of operations.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections*, which replaces APB Opinion No. 20, *Accounting Changes* and SFAS No. 3, *Reporting Accounting Changes in Interim Financial Statements.* SFAS 154 retained accounting guidance related to changes in estimates, changes in a reporting entity and error corrections. However, changes in accounting principles must be accounted for retrospectively by modifying the financial statements of prior periods unless it is impracticable to do so. SFAS 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005. The adoption of SFAS 154 did not have a material impact on our financial position or results of operations.

The SEC issued Staff Accounting Bulletin, or SAB, No. 108, *Considering the Effects of Prior Year Misstatements, When Quantifying Misstatements in Current Year Financial Statements*, on September 13, 2006. SAB No. 108 was issued to address diversity in practice in quantifying financial statement misstatements and the potential under current practice for the build-up of improper amounts on the balance sheet. The effects of applying the guidance issued in SAB No. 108 are to be reflected in annual financial statements covering the first fiscal year ending after November 15, 2006. The initial adoption of SAB No. 108 in 2006 did not have an impact on our financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements,* which establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS No. 157 states that fair value is the price that would be received to sell the asset or paid to transfer the liability (an exit price), not the price that would be paid to acquire the asset or received to assume the liability (an entry price). The statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We are currently evaluating the effect that this statement will have on our financial statements.

In September 2006, the FASB issued FASB Staff Position, or FSP, No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*, that disallowed the accrue-in-advance method for planned major maintenance activities. Our scheduled turnaround activities are considered planned major maintenance activities. Since we do not use the accrue-in-advance method of accounting for our turnaround activities, this FSP has no impact on our financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS 159). Under this standard, an entity is required to provide additional information that will assist investors and other users of financial information to more easily understand the effect of the company s choice to use fair value on its earnings. Further, the entity is required to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. This standard does not eliminate the disclosure requirements about fair value measurements included in SFAS 157 and SFAS No. 107, Disclosures about Fair Value of Financial Instruments. SFAS 159 is effective for fiscal years beginning after November 15, 2007, and early adoption is permitted as of January 1, 2007, provided that the entity makes that choice in the first quarter of 2007 and also elects to apply the provisions of SFAS 157. We are currently evaluating the potential impact that SFAS 159 will have on our financial condition, results of operations and cash flows.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements as such term is defined within the rules and regulations of the SEC.

Quantitative and Qualitative Disclosures About Market Risk

The risk inherent in our market risk sensitive instruments and positions is the potential loss from adverse changes in commodity prices and interest rates. None of our market risk sensitive instruments are held for trading.

Commodity Price Risk

Our petroleum business, as a manufacturer of refined petroleum products, and the nitrogen fertilizer business, as a manufacturer of nitrogen fertilizer products, all of which are commodities, have exposure to market pricing for products sold in the future. In order to realize value from our processing capacity, a positive spread between the cost of raw materials and the value of finished products must be achieved (i.e., gross margin or crack spread). The physical commodities that comprise our raw materials and finished goods are typically bought and sold at a spot or index price that can be highly variable.

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We use a crude oil purchasing intermediary which allows us to take title and price of our crude oil at the refinery, as opposed to the crude origination point, reducing our risk associated with volatile commodity prices by shortening the commodity conversion cycle time. The commodity conversion cycle time refers to the time elapsed between raw material acquisition and the sale of finished goods. In addition, we seek to reduce the variability of commodity price exposure by engaging in hedging strategies and transactions that will serve to protect gross margins as forecasted in the annual operating plan. Accordingly, we use financial derivatives to economically hedge future cash flows (i.e., gross margin or crack spreads) and product inventories. With regard to our hedging activities, we may enter into, or have entered into, derivative instruments which serve to:

- lock in or fix a percentage of the anticipated or planned gross margin in future periods when the derivative market offers commodity spreads that generate positive cash flows; and

- hedge the value of inventories in excess of minimum required inventories.

Further, we intend to engage only in risk mitigating activities directly related to our business.

Basis Risk. The effectiveness of our derivative strategies is dependent upon the correlation of the price index utilized for the hedging activity and the cash or spot price of the physical commodity for which price risk is being mitigated. Basis risk is a term we use to define that relationship. Basis risk can exist due to several factors including time or location differences between the derivative instrument and the underlying physical commodity. Our selection of the appropriate index to utilize in a hedging strategy is a prime consideration in our basis risk exposure.

Examples of our basis risk exposure are as follows:

- Time Basis In entering over-the-counter swap agreements, the settlement price of the swap is typically the average price of the underlying commodity for a designated calendar period. This settlement price is based on the assumption that the underling physical commodity will price ratably over the swap period. If the commodity does not move ratably over the periods then weighted average physical prices will be weighted differently than the swap price as the result of timing.

- Location Basis In hedging NYMEX crack spreads, we experience location basis as the settlement of NYMEX refined products (related more to New York Harbor cash markets) which may be different than the prices of refined products in our Group 3 pricing area.

Price and Basis Risk Management Activities. Our most prevalent risk management activity is to sell forward the crack spread when opportunities exist to lock in a margin sufficient to meet our cash obligations or our operating plan. Selling forward derivative contracts for which the underlying commodity is the crack spread enables us to lock in a margin on the spread between the price of crude oil and price of refined products. The commodity derivative contracts are either exchange-traded contracts in the form of futures contracts or over-the-counter contracts in the form of commodity price swaps.

In the event our inventories exceed our target base level of inventories, we may enter into commodity derivative contracts to manage our price exposure to our inventory positions that are in excess of our base level. Excess inventories are typically the result of plant operations such as a turnaround or other plant maintenance. The commodity derivative contracts are either exchange-traded contracts in the form of futures contracts or over-the-counter contracts in the form of commodity price swaps.

To reduce the basis risk between the price of products for Group 3 and that of the NYMEX associated with selling forward derivative contracts for NYMEX crack spreads, we may enter into basis swap positions to lock the price difference. If the difference between the price of products on the NYMEX and Group 3 (or some other price benchmark as we may deem appropriate) is different than the value contracted in the swap, then we will receive from or owe to the counterparty the difference on each unit of product contracted in the swap, thereby completing the locking of our margin. An example of our use of a basis swap is in the winter heating oil season. The risk associated with not hedging the basis when using NYMEX forward contracts to fix future margins is if the crack spread increases based on prices traded on NYMEX while Group 3 pricing remains flat or decreases then we would be in a position to lose money on the derivative position while not earning an offsetting additional margin on the physical position based on the Group 3 pricing.

On June 30, 2007, we had the following open commodity derivative contracts whose unrealized gains and losses are included in gain (loss) on derivatives in the consolidated statements of operations:

Successor s Petroleum Segment holds commodity derivative contracts in the form of three swap agreements for the period from July 1, 2005 to June 30, 2010 with J. Aron, a subsidiary of The Goldman Sachs Group, Inc. and a related party of ours. The swap agreements were originally executed on June 16, 2005 in conjunction with the Subsequent Acquisition of Immediate Predecessor and required under the terms of our long-term debt agreements. These agreements were subsequently assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. The total notional quantities on the date of execution were 100,911,000 barrels of crude oil; 2,348,802,750 gallons of unleaded gasoline and 1,889,459,250 gallons of heating oil; pursuant to these swaps, we receive a fixed price with respect to the heating oil and the unleaded gasoline while we pay a fixed price with respect to crude oil. In June 2006, a subsequent swap was entered into with J. Aron to effectively reduce our unleaded notional quantity and increase our heating oil notional quantity by 229,671,750 gallons over the period July 2, 2007 to June 30, 2010. Additionally, several other swaps were entered into with J. Aron to adjust effective net notional amounts of the aggregate position to better align with actual production volumes. The swap agreements were executed at the prevailing market rate at the time of execution and management believed the swap agreements would provide an economic hedge on future transactions. At June 30, 2007 the net notional open amounts under these swap agreements were 54,783,750 barrels of crude oil, 1,148,358,750 gallons of heating oil and 1,152,558,750 gallons of unleaded gasoline. The purpose of these contracts is to economically hedge 27,341,875 barrels of heating oil crack spreads, the price spread between crude oil and heating oil, and 27,441,876 barrels of unleaded gasoline crack spreads, the price spread between crude oil and unleaded gasoline. These open contracts had a total unrealized net loss at June 30, 2007 of approximately $188.5 million.

Successor s Petroleum Segment also holds various NYMEX positions through UBS Securities LLC. At June 30, 2007, we were short 250 crude contracts, 90 heating oil contracts and 150 unleaded contracts, reflecting an unrealized loss of $0.8 million on that date.

As of June 30, 2007, a $1.00 change in quoted futures price for the crack spreads described in the first bullet point would result in a $54.8 million change to the fair value of the derivative commodity position and the same change in net income.

Interest Rate Risk

As of June 30, 2007, all of our $773.1 million of outstanding term debt was at floating rates. An increase of 1.0% in the LIBOR rate would result in an increase in our interest expense of approximately $7.8 million per year.

As of June 30, 2007, all of our $40.0 million of outstanding revolving debt was at floating rates based on prime. If this amount remained outstanding for an entire year, an increase of 1.0% in the prime rate would result in an increase in our interest expense of approximately $0.4 million per year.

In an effort to mitigate the interest rate risk highlighted above and as required under our then-existing first and second lien credit agreements, we entered into several interest rate swap agreements in 2005. These swap agreements were entered into with counterparties that we believe to be creditworthy. Under the swap agreements, we pay fixed rates and receive floating rates based on the three-month LIBOR rates, with payments calculated on the notional amounts set for in the table below. The interest rate swaps are settled quarterly and marked to market at each reporting date.

Notional Amount	Effective Date	Termination Date	Fixed Rate
$325.0 million	6/29/07	3/30/08	4.195%
$250.0 million	3/31/08	3/30/09	4.195%
$180.0 million	3/31/09	3/30/10	4.195%
$110.0 million	3/31/10	6/29/10	4.195%

We have determined that these interest rate swaps do not qualify as hedges for hedge accounting purposes. Therefore, changes in the fair value of these interest rate swaps are included in income in the period of change. Net realized and unrealized gains or losses are reflected in the gain (loss) for derivative activities at the end of each period. For the year ended December 31, 2006, we had $3.7 million of realized and unrealized gains on these interest rate swaps and for the six months ended June 30, 2007, we had $2.4 million of realized and unrealized gains.

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INDUSTRY OVERVIEW

Oil Refining Industry

Oil refining is the process of separating the wide spectrum of hydrocarbons present in crude oil, and in certain processes, modifying the constituent molecular structures, for the purpose of converting them into marketable finished, or refined, petroleum products optimized for specific end uses. Refining is primarily a margin-based business where both the feedstocks (the petroleum products such as crude oil or natural gas liquids that are processed and blended into refined products) and the refined finished products are commodities. It is important for a refinery to maintain high throughput rates (the volume per day processed through the refinery) and capacity utilization given the substantial fixed component in the total operating costs. There are also material variable costs associated with the fuel and by-product components that become increasingly expensive as crude prices increase. The refiner s goal is to achieve highest profitability by maximizing the yields of high value finished products and by minimizing feedstock and operating costs.

According to the Energy Information Administration, or the EIA, as of January 1, 2007, there were 145 oil refineries operating in the United States, with the 15 smallest each having a capacity of 12,500 bpd or less, and the 10 largest having capacities ranging from 306,000 to 562,500 bpd. Refiners typically are structured as part of a fully or partially integrated oil company, or as an independent entity, such as our Company.

Refining Margins

A variety of so called crack spread indicators are used to track the profitability of the refining industry. Among those of most relevance to our refinery are (1) the gasoline crack spread, (2) the heat crack spread, and (3) the 2-1-1 crack spread. The gasoline crack spread is the simple difference in per barrel value between reformulated gasoline (gasoline with compounds or properties which meet the requirements of the reformulated gasoline regulations) in New York Harbor as traded on the New York Mercantile Exchange, or NYMEX, and the NYMEX prompt price of West Texas Intermediate, or WTI, crude oil on any given day. This provides a measure of the profitability when producing gasoline. The heat crack spread is the similar measure of the price of Number 2 heating oil in New York Harbor as traded on the NYMEX, relative to the value of WTI crude which provides a measure of the profitability of producing distillates. The 2-1-1 crack spread is a composite spread that assumes for simplification and comparability purposes that for every two barrels of WTI consumed, a refinery produces one barrel of gasoline and one barrel of heating oil; the spread is based on the NYMEX price and delivery of gasoline and heating oil in New York Harbor. The 2-1-1 crack spread provides a measure of the general profitability of a medium high complexity refinery on the day that the spread is computed. The ability of a crack spread to measure profitability is affected by the absolute crude price.

Our refinery uses a consumed 2-1-1 crack spread to measure its specific daily performance in the market. The consumed 2-1-1 crack spread assumes the same relative production of gasoline and heating oil from crude, so like the NYMEX based 2-1-1 crack spread, it has an inherent inaccuracy because the refinery does not produce exactly two barrels of high valued products for each two barrels of crude oil, and the relative proportions of gasoline to heating oil will vary somewhat from the 1:1 relationship. However, the consumed 2-1-1 crack spread is an economically more accurate measure of performance than the NYMEX based 2-1-1 crack spread since the crude price used represents the price of our actual charged crude slate and is based on the actual sale values in our marketing region, rather than on New York Harbor NYMEX numbers. Average 2-1-1 crack spreads vary from region to region depending on the supply and demand balances of crude oils and refined products and can vary seasonally and from year to year reflecting more macroeconomic factors.

Although refining margins, the difference between the per barrel prices for refined products and the cost of crude oil, can be volatile during short term periods of time due to seasonality of demand,

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refinery outages, extreme weather conditions and fluctuations in levels of refined product held in storage, longer-term averages have steadily increased over the last 10 years as a result of the improving fundamentals for the refining industry. For example, the NYMEX based 2-1-1 crack spread averaged $3.88 per barrel from 1994 through 1998 compared to $9.76 per barrel from 2003 to June 30, 2007. The following chart shows a rolling average of the NYMEX based 2-1-1 crack spread from 1994 through 2006:

Source: Platts

Refining Market Trends

The supply and demand fundamentals of the domestic refining industry have improved since the 1990s and are expected to remain favorable as the growth in demand for refined products continues to exceed increases in refining capacity. Over the next two decades, the EIA projects that U.S. demand for refined products will grow at an average of 1.5% per year compared to total domestic refining capacity growth of only 1.3% per year. Approximately 83.3% of the projected demand growth is expected to come from the increased consumption of light refined products (including gasoline, diesel, jet fuel and liquefied petroleum gas), which are more difficult and costly to produce than heavy refined products (including asphalt and carbon black oil).

High capital costs, historical excess capacity and environmental regulatory requirements have limited the construction of new refineries in the United States over the past 30 years. According to the EIA, domestic refining capacity decreased approximately 7% between January 1981 and January 2007 from 18.6 million bpd to 17.3 million bpd, as more than 175 generally small and unsophisticated refineries that were unable to process heavy crude into a marketable product mix have been shut down, and no new major refinery has been built in the United States. The implementation of the federal Tier II low sulfur fuel regulations is expected to further reduce existing refining capacity.

As reflected within the U.S. Days Forward Supply and the U.S. Mogas Inventory statistics provided by the EIA, the gasoline available for consumption in the United States has declined year after year. This trend is in most part attributable to a steady increase in demand that has not been matched by an equal increase in supply. Although existing refiners are improving their utilization rates, the total number of refiners has declined. As a result, the U.S. has been dependent on imported fuels to meet domestic demand while the global supply which has historically been available for importation has been subject to increasing worldwide demand. With this reduction in days of available supply, we believe the U.S. will occasionally experience periods of little or no supply of gasoline in various markets as the supply and distribution system continues to strain to match available inventory with consumer demand.

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In order to meet the increasing demands of the market, U.S. refineries have pursued efficiency measures to improve existing production levels. These efficiency measures and other initiatives, generally known as capacity creep, have raised productive capacity of existing refineries by approximately 1% per year since 1993. According to the EIA, between 1981 and 2004, refinery utilization increased from 69% to 93%. Over the next 20 years, the EIA projects that utilization will remain high relative to historic levels, ranging from 92% to 95% of design capacity.

Source: EIA

The price discounts available to refiners of heavy sour crude oil have widened as many refiners have turned to sweeter and lighter crude oils to meet lower sulfur fuel specifications, which has resulted in increasing the surplus of sour and heavy crude oils. As the global economy has improved, worldwide crude oil demand has increased, and OPEC and other producers have tended to incrementally produce more of the sour or heavier crude oil varieties. We believe that the combination of increasing worldwide supplies of lower cost sour and heavy crude oils and increasing demand for sweet and light crude oils will provide a cost advantage to refineries with configurations that are able to process sour crude oils.

We expect refined products that meet new and evolving fuel specifications will account for an increasing share of total fuel demand, which will benefit refiners who are able to efficiently produce these fuels. As part of the Clean Air Act, major metropolitan areas in the United States with air pollution problems must require the sale and use of reformulated gasoline meeting certain environmental standards in their jurisdictions. Boutique fuels, such as low vapor pressure Kansas City gasoline, enable refineries capable of producing such refined products to achieve higher margins.

Due to the ongoing supply and demand imbalance, the United States continues to be a net refined products importer. Imports, largely from northwest Europe and Asia, accounted for over 12% of total U.S. consumption in 2005. The level of imports generally increases during periods when refined product prices in the United States are materially higher than in Europe and Asia.

Based on the strong fundamentals for the global refining industry, capital investments for refinery expansions and new refineries in international markets have increased during the recent year. However, the competitive threat faced by domestic refiners is limited by U.S. fuel specifications and increasing foreign demand for refined products, particularly for light transportation fuels.

Certain regional markets in the United States, such as the Coffeyville supply area, do not have the necessary refining capacity to produce a sufficient amount of refined products to meet area demand and therefore rely on pipelines and other modes of transportation for incremental supply from other regions of the United States and globally. The shortage of refining capacity is a factor that results in local refiners serving these markets earning generally higher margins on their product sales than those who have to transport their products to this region over long distances.

Notwithstanding the trends described above, the refining industry is cyclical and volatile and has undergone downturns in the past. See Risk Factors.

Refinery Locations

A refinery s location can have an important impact on its refining margins because location can influence access to feedstocks and efficient distribution. There are five regions in the United States, the Petroleum Administration for Defense Districts (PADDs), that have historically experienced varying levels of refining profitability due to regional market conditions. Refiners located in the U.S. Gulf Coast region operate in a highly competitive market due to the fact that this region (PADD III) accounts for approximately 38% of the total number of U.S. refineries and approximately 48% of the country s refining capacity. PADD I represents the East Coast, PADD IV the Rocky Mountains and PADD V is the West Coast.

Coffeyville operates in the Midwest (PADD II) region of the US. In 2006, demand for gasoline and distillates (primarily diesel fuels, kerosene and jet fuel) exceeded refining production in the Coffeyville supply area by approximately 22%, which created a need to import a significant portion of the region s requirement for petroleum products from the U.S. Gulf Coast and other regions. The deficit of local refining capacity benefits local refined product pricing and could generally lead to higher margins for local refiners such as our company.

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Nitrogen Fertilizer Industry

Plant Nutrition and Nitrogen Fertilizers

Commercially produced fertilizers give plants the primary nutrients needed in a form they can readily absorb and use. Nitrogen is an essential element for plant growth. Absorbed by plants in larger amounts than other nutrients, nitrogen makes plants green and healthy and is the nutrient most responsible for increasing yields in crop plants. Although plants will absorb nitrogen from organic matter and soil materials, this is usually not sufficient to satisfy the demands of crop plants. The supply of nutrients must, accordingly, be supplemented with fertilizers to meet the requirements of crops during periods of plant growth, to replenish nutrients removed from the soil through crop harvesting and to provide those nutrients that are not already available in appropriate amounts in the soil. The two most important sources of nutrients are manufactured or mineral fertilizers and organic manures. Farmers determine the types, quantities and proportions of fertilizer to apply to their fields depending on, among other factors, the crop, soil and weather conditions, regional farming practices, and fertilizer and crop prices.

Nitrogen, which typically accounts for approximately 60% of worldwide fertilizer consumption in any planting season, is an essential element for most organic compounds in plants as it promotes protein formation and is a major component of chlorophyll, which helps to promote green healthy growth and high yields. There are no substitutes for nitrogen fertilizers in the cultivation of high-yield crops such as corn, which on average requires 100-160 pounds of nitrogen for each acre of plantings. The four principal nitrogen based fertilizer products are:

Ammonia. Ammonia is used in limited quantities as a direct application fertilizer, and is primarily used as a building block for other nitrogen products, including intermediate products for industrial applications and finished fertilizer products. Ammonia, consisting of 82% nitrogen, is stored either as a refrigerated liquid at minus 27 degrees, or under pressure if not refrigerated. It is gaseous at ambient temperatures and is injected into the soil as a gas. The direct application of ammonia requires farmers to make a considerable investment in pressurized storage tanks and injection machinery, and can take place only under a narrow range of ambient conditions.

Urea. Urea is formed by reacting ammonia with carbon dioxide, or CO_2, at high pressure. From the warm urea liquid produced in the first, wet stage of the process, the finished product is mostly produced as a coated, granular solid containing 46% nitrogen and suitable for use in bulk fertilizer blends containing the other two principal fertilizer nutrients, phosphate and potash. We do not produce merchant urea.

Ammonium Nitrate. Ammonium nitrate is another dry, granular form of nitrogen based fertilizer. It is produced by converting ammonia to nitric acid in the presence of a platinum catalyst reaction, then further reacting the nitric acid with additional volumes of ammonia to form ammonium nitrate. We do not produce this product.

Urea Ammonium Nitrate Solution (UAN). Urea can be combined with ammonium nitrate solution to make liquid nitrogen fertilizer (urea ammonium nitrate or UAN). These solutions contain 32% nitrogen and are easy to store and transport and provide the farmer with the most flexibility in tailoring fertilizer, pesticide and fungicide applications.

In 2006, we produced approximately 369,300 tons of ammonia, of which approximately two-thirds was upgraded into approximately 633,100 tons of UAN.

Ammonia Production Technology Advantages of Coke Gasification

Ammonia is produced by reacting gaseous nitrogen with hydrogen at high pressure and temperature in the presence of a catalyst. Traditionally, nearly all hydrogen produced for the manufacture of nitrogen based fertilizers is produced by reforming natural gas at a high temperature

and pressure in the presence of water and a catalyst. This process consumes a significant amount of natural gas and is believed to become unprofitable as the natural gas input costs increase.

Alternatively, hydrogen for ammonia can also be produced by gasifying pet coke. Pet coke is a coal-like substance that is produced during the refining process. The coke gasification process, which the nitrogen fertilizer business commercially employs at its fertilizer plant, the only such plant in North America, takes advantage of the large cost differential between pet coke and natural gas in current markets. The plant s coke gasification process allows it to use less than 1% of the natural gas relative to other nitrogen based fertilizer facilities that are heavily dependent upon natural gas and are thus heavily impacted by natural gas price swings. The nitrogen fertilizer business also benefits from the ready availability of pet coke supply from our refinery plant. Pet coke is a refinery by-product which if not used in the fertilizer plant would otherwise be sold as fuel, generating less value to the company.

Fertilizer Consumption Trends

Global demand for fertilizers typically grows at predictable rates and tends to correspond to growth in grain production. Global fertilizer demand is driven in the long-term primarily by population growth, increases in disposable income and associated improvements in diet. Short-term demand depends on world economic growth rates and factors creating temporary imbalances in supply and demand. These factors include weather patterns, the level of world grain stocks relative to consumption, agricultural commodity prices, energy prices, crop mix, fertilizer application rates, farm income and temporary disruptions in fertilizer trade from government intervention, such as changes in the buying patterns of large countries like China or India. According to the International Fertilizer Industry Association, or IFA, from 1960 to 2005, global fertilizer demand has grown 3.7% annually and global nitrogen demand has grown at a faster rate of 4.8% annually. According to the IFA, during that 45-year period, North American fertilizer demand has grown 2.4% annually with North American nitrogen demand growing at a faster rate of 3.3% annually.

In 2000, the FAO projected an increase in major world crop production from 1995/97 to 2030 of approximately 76%. The annual growth rate for fertilizer consumption through 2030 is projected by the FAO to be between 0.7% and 1.3% per year. This forecast assumes a slowdown in the growth of the world s population and crop production, and an improvement in fertilizer use efficiency.

According to the United States Department of Agriculture, U.S. farmers planted 92.9 million acres of corn in 2007, exceeding the 2006 planted area by 19 percent. This increase was driven in part by ethanol demand. The actual planted acreage is the highest on record since 1944, when farmers planted 95.5 million acres of corn. Farmers in nearly all states increased their planted corn acreage in 2007. State records were established in Illinois, Indiana, Minnesota and North Dakota, while Iowa led all states in total planted corn acres. A net effect of these additional planted acres increased the demand for nitrogen fertilizers over 1 million tons. This equates to an annual increase of 3.3 million tons of UAN, or approximately 5 times Coffeyville s total UAN production.

The Farm Belt Nitrogen Market

All of the nitrogen fertilizer business product shipments target freight advantaged destinations located in the U.S. farm belt. The farm belt refers to the states of Illinois, Indiana, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Texas and Wisconsin. Because shipping ammonia requires refrigerated or pressured containers and UAN is more than 65% water, transportation cost is substantial for ammonia and UAN producers. As a result, locally based fertilizer producers, such as the nitrogen fertilizer business, enjoy a distribution cost advantage over U.S. Gulf Coast ammonia and UAN importers. Southern Plains ammonia and Corn Belt UAN 32 prices averaged $288/ton and $165/ton, respectively, for the 2002 through 2006 period, based on data provided

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by Blue Johnson & Associates. The volumes of ammonia and UAN sold into certain farm belt markets are set forth in the table below:

Recent United States Ammonia and UAN Demand in Selected Mid-continent Areas

State	Ammonia Quantity	UAN 32 Quantity
	(thousand tons per year)	
Texas	2,300	850
Oklahoma	80	225
Kansas	370	670
Missouri	325	250
Iowa	690	865
Nebraska	335	1,100
Minnesota	335	195

Source: Blue Johnson & Associates Inc.

Fertilizer Pricing Trends

The nitrogen fertilizer industry is cyclical and relatively volatile, reflecting the commodity nature of ammonia and the major finished fertilizer products (e.g., urea). Although domestic industry-wide sales volumes of nitrogen based fertilizers vary little from one fertilizer season to the next due to the need to apply nitrogen every year to maintain crop yields, in the normal course of business industry participants are exposed to fluctuations in supply and demand, which can have significant effects on prices across all participants commodity business areas and products and, in turn, their operating results and profitability. Changes in supply can result from capacity additions or reductions and from changes in inventory levels. Demand for fertilizer products is dependent on demand for crop nutrients by the global agricultural industry, which, in turn, depends on, among other things, weather conditions in particular geographical regions. Periods of high demand, high capacity utilization and increasing operating margins tend to result in new plant investment, higher crop pricing and increased production until supply exceeds demand, followed by periods of declining prices and declining capacity utilization, until the cycle is repeated. Due to dependence of the prevalent nitrogen fertilizer technology on natural gas, the marginal cost and pricing of fertilizer products also tend to exhibit positive correlation with the price of natural gas.

Current strong industry fundamentals include U.S. producer UAN inventories that are lower than they were during the prior year, a tight U.S. import market which contracted sharply in late 2006, and nitrogen fertilizer global capacity utilization which is projected to be near 85% through 2010. These fundamentals have been driven, in part, by increased U.S. corn plantings, which increased by 19% in 2007, and increasing worldwide natural gas prices. Due to these trends, our second quarter 2007 UAN order book of 317,900 tons was priced on average at $230.17 per ton as compared to an average of $169.45 per ton in the first quarter of 2007.

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The historical average annual U.S. Corn Belt ammonia prices as well as natural gas and crude oil prices are detailed in the table below.

Year	Natural Gas ($/million btu)	WTI ($/bbl)	Ammonia ($/ton)
1990	1.78	24.53	125
1991	1.53	21.55	130
1992	1.73	20.57	134
1993	2.11	18.43	139
1994	1.94	17.16	197
1995	1.69	18.38	238
1996	2.50	22.01	217
1997	2.48	20.59	220
1998	2.16	14.43	162
1999	2.32	19.26	145
2000	4.32	30.28	208
2001	4.06	25.92	262
2002	3.39	26.19	191
2003	5.49	31.03	292
2004	5.90	41.47	326
2005	8.92	56.58	394
2006	6.73	66.09	379
2007 (through June 30)	7.36	61.58	432

Source: Bloomberg (natural gas and WTI) and Blue Johnson & Associates, Inc. (ammonia)

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BUSINESS

We are an independent refiner and marketer of high value transportation fuels and, through a limited partnership in which we will initially own all of the interests (other than the managing general partner interest and associated IDRs), a producer of ammonia and UAN fertilizers. We are one of only seven petroleum refiners and marketers in the Coffeyville supply area (Kansas, Oklahoma, Missouri, Nebraska and Iowa) and, at current natural gas prices, the nitrogen fertilizer business is the lowest cost producer and marketer of ammonia and UAN in North America.

Our petroleum business includes a 113,500 bpd, complex full coking sour crude refinery in Coffeyville, Kansas (with capacity expected to reach approximately 115,000 bpd by the end of 2007). In addition, our supporting businesses include (1) a crude oil gathering system serving central Kansas, northern Oklahoma and southwest Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, and (3) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and to customers at throughput terminals on Magellan refined products distribution systems. In addition to rack sales (sales which are made at terminals into third party tanker trucks), we make bulk sales (sales through third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise and NuStar. Our refinery is situated approximately 100 miles from Cushing, Oklahoma, one of the largest crude oil trading and storage hubs in the United States, served by numerous pipelines from locations including the U.S. Gulf Coast and Canada, providing us with access to virtually any crude variety in the world capable of being transported by pipeline.

The nitrogen fertilizer business is the only operation in North America that utilizes a coke gasification process to produce ammonia (based on data provided by Blue Johnson & Associates). A majority of the ammonia produced by the fertilizer plant is further upgraded to UAN fertilizer (a solution of urea and ammonium nitrate in water used as a fertilizer). By using pet coke (a coal-like substance that is produced during the refining process) instead of natural gas as raw material, at current natural gas prices the nitrogen fertilizer business is the lowest cost producer of ammonia and UAN in North America. Furthermore, on average, over 80% of the pet coke utilized by the fertilizer plant is produced and supplied to the fertilizer plant as a by-product of our refinery. As such, the nitrogen fertilizer business benefits from high natural gas prices, as fertilizer prices increase with natural gas prices, without a directly related change in cost (because pet coke rather than more expensive natural gas is used as a primary raw material).

We have two business segments: petroleum and nitrogen fertilizer. For the fiscal years ended December 31, 2004, 2005, 2006 and for the twelve months ended June 30, 2007, we generated combined net sales of $1.7 billion, $2.4 billion, $3.0 billion and $2.7 billion, respectively, and operating income of $111.2 million, $270.8 million, $281.6 million and $190.5 million, respectively. Our petroleum business generated $1.6 billion, $2.3 billion, $2.9 billion and $2.6 billion of our combined net sales, respectively, over these periods, with the nitrogen fertilizer business generating substantially all of the remainder. In addition, during these periods, our petroleum business contributed $84.8 million, $199.7 million, $245.6 million and $170.5 million of our combined operating income, respectively, with the nitrogen fertilizer business contributing substantially all of the remainder.

Significant Milestones Since the Change of Control in June 2005

Following the acquisition by certain affiliates of the Goldman Sachs Funds and the Kelso Funds in June 2005, a new senior management team led by John J. Lipinski, our Chief Executive Officer, was formed that combined selected members of existing management with experienced new members. Our new senior management team has executed several key strategic initiatives that we believe have significantly enhanced our competitive position and improved our financial and operational performance.

Increased Refinery Throughput and Yields. Management s focus on crude slate optimization (the process of determining the most economic crude oils to be refined), reliability, technical support and operational excellence coupled with prudent expenditures on equipment has significantly improved the operating metrics of the refinery. The refinery s crude throughput rate (the volume per day processed through the refinery) has increased from an average of less than 90,000 bpd to an average of greater than 102,000 bpd in the second quarter of 2006, with peak daily rates in excess of 113,500 bpd of crude in June 2007. Crude throughputs averaged 94,500 bpd for 2006, an improvement of over 3,400 bpd over 2005. Recent operational improvements at the refinery have also allowed us to produce higher volumes of favorably priced distillates (primarily No. 1 diesel fuel and kerosene), premium gasoline and boutique gasoline grades.

Diversified Crude Feedstock Variety. We have expanded the variety of crude grades processed in any given month from a limited few to over a dozen, including onshore and offshore domestic grades, various Canadian sours, heavy sours and sweet synthetics, and a variety of South American and West African imported grades. This has improved our crude purchase cost discount to WTI from $3.33 per barrel in 2005 to $4.75 per barrel in 2006.

Expanded Direct Rack Sales. We have significantly expanded and intend to continue to expand rack marketing of refined products (petroleum products such as gasoline and diesel fuel) directly to customers rather than origin bulk sales. Today, we sell over 23% of our produced transportation fuels throughout the Coffeyville supply area within the mid-continent, at enhanced margins, through our proprietary terminals and at Magellan s throughput terminals. With the expanded rack sales program, we improved our net income for 2006 compared to 2005.

Significant Plant Improvement and Capacity Expansion Projects. Management has identified and developed several significant capital projects since June 2005 primarily aimed at (1) expanding refinery and nitrogen fertilizer plant capacity (throughput that the plants are capable of sustaining on a daily basis), (2) enhancing operating reliability and flexibility, (3) complying with more stringent environmental, health and safety standards, and (4) improving our ability to process heavier sour crude feedstock varieties (petroleum products that are processed and blended into refined products). We have completed most of these capital projects and expect to complete substantially all of the capital projects by the end of 2007. The estimated total cost of these programs is $522 million (including $172 million in expenditures and $3.7 million in capitalized interest for our refinery expansion project), the majority of which has already been spent.

The following major projects under this program were completed in 2006:

- Construction of a new 23,000 bpd high pressure diesel hydrotreater and associated new sulfur recovery unit, which will allow the facility to meet the EPA Tier II Ultra Low Sulfur Diesel federal regulations; and

- Expansion of one of the two gasification units within the fertilizer complex, which is expected to increase ammonia production by over 6,500 tons per year.

The following major projects under this program, substantially all of which are completed, are intended to increase refinery processing capacity to up to approximately 115,000 bpd, increase gasoline production and improve our liquid volume yield:

- Refinery-wide capacity expansion by increasing throughput of the existing fluid catalytic cracking unit (the unit that converts gas oil from the crude unit or coker unit into liquified petroleum gas, distillates and gasoline blendstocks), the delayed coker (the unit that processes heavy feedstock and produces lighter products and pet coke), and other major process units; and

Construction of a new grass roots 24,000 bpd continuous catalytic reformer to be completed by the end of 2007.

Once completed, these projects are intended to significantly enhance the profitability of the refinery in environments of high crack spreads and allow the refinery to operate more profitably at lower crack spreads than is currently possible. We intend to finance these capital projects with cash

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from our operations and occasional borrowings from our credit facilities. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Debt and Description of Our Indebtedness and the Cash Flow Swap.

Our Competitive Strengths

Regional Advantage and Strategic Asset Location. Our refinery is one of only seven refineries located in the Coffeyville supply area within the mid-continent region, where demand for refined products exceeded refining production by approximately 22% in 2006. We estimate that this favorable supply/demand imbalance combined with our lower pipeline transportation cost as compared to the U.S. Gulf Coast refiners has allowed us to generate refining margins, as measured by the 2-1-1 crack spread, that have exceeded U.S. Gulf Coast refining margins by approximately $1.74 per barrel on average for the last four years. The 2-1-1 crack spread is a general industry standard that approximates the per barrel refining margin resulting from processing two barrels of crude oil to produce one barrel of gasoline and one barrel of diesel fuel.

In addition, the nitrogen fertilizer business is geographically advantaged to supply products to markets in Kansas, Missouri, Nebraska, Iowa, Illinois and Texas without incurring intermediate transfer, storage, barge or pipeline freight charges. Because the nitrogen fertilizer business does not incur these costs, this geographic advantage provides it with a distribution cost benefit over U.S. Gulf Coast ammonia and UAN importers, assuming in each case freight rates and pipeline tariffs for U.S. Gulf Coast importers as recently in effect.

Access to and Ability to Process Multiple Crude Oils. Since June 2005 we have significantly expanded the variety of crude grades processed in any given month and have reduced our acquisition cost of crude relative to WTI by approximately $1.50 per barrel in 2006 compared to 2005. While our proximity to the Cushing crude oil trading hub minimizes the likelihood of an interruption to our supply, we intend to further diversify our sources of crude oil. Among other initiatives in this regard, we have secured shipper rights on the newly built Spearhead pipeline, owned by CCPS Transportation, LLC (which is ultimately owned by Enbridge), which connects Chicago to the Cushing hub. We have also committed to additional pipeline capacity on the proposed Keystone pipeline project currently under development by TransCanada Keystone Pipeline, LP which will provide us with access to incremental oil supplies from Canada. We also own and operate a crude gathering system serving northern Oklahoma, central Kansas and southwest Nebraska, which allows us to acquire quality crudes at a discount to WTI.

High Quality, Modern Asset Base with Solid Track Record. We operate a complex full coking sour crude refinery. Complexity is a measure of a refinery s ability to process lower quality crude in an economic manner; greater complexity makes a refinery more profitable. Our refinery s complexity allows us to optimize the yields (the percentage of refined product that is produced from crude and other feedstocks) of higher value transportation fuels (gasoline and distillate), which currently account for approximately 93% of our liquid production output. From 1995 through August 31, 2007, we have invested approximately $673 million to modernize our oil refinery and to meet more stringent U.S. environmental, health and safety requirements. As a result, we have achieved significant increases in our refinery crude throughput rate from an average of less than 90,000 bpd prior to June 2005 to over 102,000 bpd in the second quarter of 2006 and over 94,500 bpd for 2006 with peak daily rates in excess of 113,500 bpd in June 2007. In addition, we have completed our scheduled 2007 refinery turnaround and expect that plant capacity will reach approximately 115,000 bpd by the end of 2007. Management s consistent focus on reliability and safety earned us the NPRA Gold Award for safety in 2005. The fertilizer plant, completed in 2000, is the newest fertilizer facility in North America, utilizes less than 1% of the natural gas relative to natural gas-based fertilizer producers and, since 2003, has demonstrated a consistent record of operating near full capacity. (The percentage of natural gas used compared to the fertilizer plant s competitors was calculated using the nitrogen fertilizer business own internal data regarding its own natural gas usage and industry data from Blue Johnson regarding typical natural gas use by other ammonia

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manufacturers.) The fertilizer plant underwent a scheduled turnaround (a periodically required procedure to refurbish and maintain the facility that involves the shutdown and inspection of major processing units) in 2006, and the plant s spare gasifier was recently expanded to increase its production capacity.

Near Term Internal Expansion Opportunities. Since June 2005, we have identified and developed several significant capital improvements primarily aimed at (1) expanding refinery capacity, (2) enhancing operating reliability and flexibility, (3) complying with more stringent environmental, health and safety standards and (4) improving our ability to process heavy sour crude feedstock varieties. With the completion of approximately $522 million of significant capital improvements, we expect to significantly enhance the profitability of our refinery during periods of high crack spreads while enabling the refinery to operate more profitably at lower crack spreads than is currently possible.

Unique Coke Gasification Fertilizer Plant. The nitrogen fertilizer plant is the only one of its kind in North America utilizing a coke gasification process to produce ammonia. The coke gasification process allows the plant to produce ammonia at a lower cost than natural gas-based fertilizer plants because it uses significantly less natural gas then its competitors. We estimate that the facility s production cost advantage over U.S. Gulf Coast ammonia producers is sustainable at natural gas prices as low as $2.50 per million Btu. This cost advantage has been more pronounced in today s environment of high natural gas prices, as the reported Henry Hub natural gas price has fluctuated between approximately $4.20 and $15.00 per million Btu since the end of 2003. The nitrogen fertilizer business has a secure raw material supply with an average of more than 80% of the pet coke required by the fertilizer plant historically supplied by our refinery. After this offering, we will continue to supply pet coke to the nitrogen fertilizer business pursuant to a 20-year intercompany agreement. The sustaining capital requirements for this business are low relative to earnings and are expected to average approximately $5 million per year as compared to $36.8 million of operating income in the nitrogen fertilizer segment for the year ended December 31, 2006. The nitrogen fertilizer business is also considering a $50 million fertilizer plant expansion, which we estimate could increase the nitrogen fertilizer plant s capacity to upgrade ammonia into premium priced UAN by 50% to approximately 1,000,000 tons per year.

Experienced Management Team. In conjunction with the acquisition of our business by Coffeyville Acquisition LLC in June 2005, a new senior management team was formed that combined selected members of existing management with experienced new members. Our senior management team averages over 28 years of refining and fertilizer industry experience and, in coordination with our broader management team, has increased our operating income and stockholder value since the acquisition of Coffeyville Resources. Mr. John J. Lipinski, our Chief Executive Officer, has over 35 years of experience in the refining and chemicals industries, and prior to joining us in connection with the acquisition of Coffeyville Resources in June 2005, was in charge of a 550,000 bpd refining system and a multi-plant fertilizer system. Mr. Stanley A. Riemann, our Chief Operating Officer, has over 33 years of experience, and prior to joining us in March 2004, was in charge of one of the largest fertilizer manufacturing systems in the United States. Mr. James T. Rens, our Chief Financial Officer, has over 18 years of experience in the energy and fertilizer industries, and prior to joining us in March 2004, was the chief financial officer of two fertilizer manufacturing companies.

Our Business Strategy

The primary business objectives for our refinery business are to increase value for our stockholders and to maintain our position as an independent refiner and marketer of refined fuels in our markets by maximizing the throughput and efficiency of our petroleum refining assets. In addition, management s business objectives on behalf of the Partnership are to increase value for our stockholders and maximize the production and efficiency of the nitrogen fertilizer facilities. We intend to accomplish these objectives through the following strategies:

Pursuing organic expansion opportunities. We continually evaluate opportunities to expand our existing asset base and consider capital projects that accentuate our core competitiveness in petroleum refining. In our petroleum business, we are currently engaged in a refinery-wide capacity expansion project that is expected to increase our operating refinery throughput to up to approximately 115,000 barrels per day by the end of 2007. We are also evaluating projects that will improve our ability to process heavy crude oil feedstocks and to increase our overall operating flexibility with respect to crude oil slates. In addition, management also continually evaluates capital projects that are intended to accentuate the Partnership s competitiveness in nitrogen fertilizer manufacturing.

Increasing the profitability of our existing assets. We strive to improve our operating efficiency and to reduce our costs by controlling our cost structure. We intend to make investments to improve the efficiency of our operations and pursue cost saving initiatives. Currently, we are in the process of completing the construction of a new grass roots continuous catalytic reformer to be completed by the end of 2007. This project is expected to increase the profitability of our petroleum business through increased refined product yields and the elimination of scheduled downtime associated with the reformer that is being replaced. In addition, this project is intended to reduce the dependence of our refinery on hydrogen supplied by the fertilizer facility, thereby allowing the fertilizer business to generate higher margins by increasing its capacity to produce ammonia and UAN rather than hydrogen.

Seeking both strategic and accretive acquisitions. We intend to consider both strategic and accretive acquisitions within the energy industry. We will seek acquisition opportunities in our existing areas of operation that have the potential for operational efficiencies. We may also examine opportunities in the energy industry outside of our existing areas of operation and in new geographic regions. In addition, working on behalf of the Partnership, management also intends to pursue strategic and accretive acquisitions within the fertilizer industry, including opportunities in different geographic regions. We have no agreements or understandings with respect to any acquisitions at the present time.

Pursuing opportunities to maximize the value of the nitrogen fertilizer limited partnership. Our management, acting on behalf of the Partnership, will continually evaluate opportunities that are intended to enable the Partnership to grow its distributable cash flow. Management s strategies specifically related to the growth opportunities of the Partnership include the following:

> *Pursuing opportunities to expand UAN production and other efficiency-based projects.* The nitrogen fertilizer business is pursuing a project that is expected to increase UAN production through the addition of a nitric acid plant, as a result of which the UAN manufacturing facility would substantially consume all of our net ammonia production. The UAN expansion is expected to be completed in 2010 and would result in an approximate 400,000 ton increase in annual UAN production. We believe that this expansion would help to improve our margins as UAN is a higher margin product as compared to ammonia. In addition, the nitrogen fertilizer business is expected to pursue several efficiency-based capital projects in order to reduce overall operating costs, or incrementally increase ammonia production for the nitrogen fertilizer business.
>
> *Leveraging the Partnership s relationship with our petroleum business.* We expect that over time, as our petroleum business grows, it will need incremental pipeline transportation and storage infrastructure services. The Partnership will be well-situated to meet these needs due to its historic relationship with and proximity to our petroleum facilities, combined with management s knowledge and expertise in hydrocarbon storage and related disciplines. The Partnership may seek to acquire new assets (including pipeline assets and storage facilities) in order to service this potential new source of revenue from our petroleum business.
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> *Acquiring assets from the petroleum business.* The Partnership may seek to purchase specific assets from our petroleum business and enter into agreements with the refinery for crude oil transportation, crude oil storage and refined fuels terminalling services. Examples of assets under consideration include our crude gathering pipeline operations serving central

Kansas, northern Oklahoma, and southwest Nebraska, the refined fuels terminal operations in Phillipsburg, Kansas and our real estate in Cushing, Oklahoma purchased for the future construction of crude oil storage tanks. We have no agreements or understandings with respect to any such acquisitions or agreements at the present time.

Pursuing opportunities in CO_2 sequestration. The nitrogen fertilizer business is currently evaluating a development plan to either sell the currently vented 850,000 tons per year of high purity anthropogenic CO_2 produced by the nitrogen fertilizer facilities into the enhanced oil recovery market or to pursue an economic means of geologically sequestering the CO_2. This project is currently in development, but is expected to result in economic benefits including the direct sale of CO_2 and the sale of verified emission credits on the open market should the credits accrete value in the future due to the implementation of mandatory emission caps for CO_2.

Constructing a third gasification unit in the nitrogen fertilizer plant. The nitrogen fertilizer business intends to pursue the feasibility of the construction and operation of an additional gasification unit to produce a synthesis gas from petroleum coke. It is expected that the addition of a third gasification unit and an additional ammonia and UAN manufacturing facility to the nitrogen fertilizer operations could result, on a long-term basis, in an approximate 1.0 million ton per year increase in UAN production. This project is in its earliest stages of review and is still subject to numerous levels of internal analysis.

Our History

Our business was founded in 1906 by The National Refining Company, which at the time was the largest independent oil refiner in the United States. In 1944 the Coffeyville refinery was purchased by the Cooperative Refinery Association, a subsidiary of a parent company that in 1966 renamed itself Farmland Industries, Inc. Our refinery assets and the nitrogen fertilizer plant were operated as a small component of Farmland Industries, Inc., an agricultural cooperative, until March 3, 2004. Farmland filed for bankruptcy protection on May 31, 2002.

Coffeyville Resources, LLC, a subsidiary of Coffeyville Group Holdings, LLC, won the bankruptcy court auction for Farmland s petroleum business and a nitrogen fertilizer plant and completed the purchase of these assets on March 3, 2004. On October 8, 2004, Coffeyville Group Holdings, LLC, through two of its wholly owned subsidiaries, Coffeyville Refining & Marketing, Inc. and Coffeyville Nitrogen Fertilizers, Inc., acquired an interest in Judith Leiber business, a designer handbag business, through an investment in CLJV Holdings, LLC (CLJV), a joint venture with The Leiber Group, Inc., whose majority stockholder was also the majority stockholder of Coffeyville Group Holdings, LLC. On June 23, 2005, the entire interest in the Judith Leiber business held by CLJV was returned to The Leiber Group, Inc. in exchange for all of its ownership interest in CLJV, resulting in a complete separation of the Immediate Predecessor and the Judith Leiber business.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC, which was formed in Delaware on May 13, 2005, acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. With the exception of crude oil, heating oil and gasoline option agreements entered into with J. Aron as of May 16, 2005, Coffeyville Acquisition LLC had no operations from its inception until the acquisition on June 24, 2005.

Prior to this offering, Coffeyville Acquisition LLC directly or indirectly owned all of our subsidiaries. We were formed in Delaware in September 2006 as a wholly owned subsidiary of Coffeyville Acquisition LLC.

Prior to the consummation of this offering, Coffeyville Acquisition LLC will redeem all of its outstanding common units held by the Goldman Sachs Funds, who will receive the same number of common units in Coffeyville Acquisition II LLC, a newly formed limited liability company to which Coffeyville Acquisition

LLC will transfer half of its interests in each of

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Coffeyville Refining & Marketing Holdings, Inc., Coffeyville Nitrogen Fertilizers, Inc. and CVR Energy. In addition, half of the common units and half of the profits interests in Coffeyville Acquisition LLC held by our executive officers will be redeemed in exchange for an equal number and type of limited liability interests in Coffeyville Acquisition II LLC. Following these redemptions, the Kelso Funds will own substantially all of the common units of Coffeyville Acquisition LLC, the Goldman Sachs Funds will own substantially all of the common units of Coffeyville Acquisition II LLC and our executive officers will own an equal number and type of interests in both Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC will own 50% of each of Coffeyville Refining & Marketing Holdings, Coffeyville Nitrogen Fertilizers and CVR Energy.

Following the redemptions by Coffeyville Acquisition LLC, we will merge a newly formed direct subsidiary of ours with Coffeyville Refining & Marketing Holdings, Inc. (which owns Coffeyville Refining & Marketing, Inc.) and merge a separate newly formed direct subsidiary of ours with Coffeyville Nitrogen Fertilizers which will make Coffeyville Refining & Marketing and Coffeyville Nitrogen Fertilizers wholly owned subsidiaries of ours. These transactions will result in a structure with CVR Energy below Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and above its two subsidiaries, so that CVR Energy will become the parent of the two subsidiaries. CVR Energy has not commenced operations and has no assets or liabilities. In addition, there are no contingent liabilities and commitments attributable to CVR Energy. The mergers provide a tax free means to put an appropriate organizational structure in place to go public and give CVR Energy the flexibility to simplify its structure in a tax efficient manner in the future if necessary.

In addition, we will transfer our nitrogen fertilizer business into a newly formed limited partnership and we will sell all of the interests of the managing general partner of this partnership to an entity owned by our controlling stockholders and senior management at fair market value on the date of the transfer.

We refer to these pre-IPO reorganization transactions in the prospectus as the Transactions.

Petroleum Business

Asset Description

We operate one of the seven refineries located in the Coffeyville supply area (Kansas, Oklahoma, Missouri, Nebraska and Iowa). The Company s complex cracking and coking oil refinery has the capacity to produce 113,500 bpd which accounts for approximately 14% of the region s output and employs techniques such as hydro processing, isomerization, alkylation and reforming in the production process. As part of our comprehensive capital expenditure program, we expect to increase the refinery capacity to up to approximately 115,000 bpd in 2007. The facility is situated on approximately 440 acres in southeast Kansas, approximately 100 miles from the Cushing, Oklahoma crude oil trading and storage hub.

The Coffeyville refinery is a complex facility. Complexity is a measure of a refinery s ability to process lower quality crude in an economic manner. It is also a measure of a refinery s ability to convert lower cost, more abundant heavier and sour crudes into greater volumes of higher valued refined products such as gasoline, thereby providing a competitive advantage over less complex refineries. At the time of the Subsequent Acquisition we had a modified Solomon complexity score of approximately 10.0. Modified Solomon complexity is a standard industry measure of a refinery s ability to process less-expensive feedstock, such as heavier and higher-sulfur content crude oils, into value-added products. Modified Solomon complexity is the weighted average of the Solomon complexity factors for each operating unit multiplied by the throughput of each refinery unit, divided by the crude capacity of the refinery. Due to the refinery s complexity, higher value products such as gasoline and diesel represent approximately an 88% product yield on a total throughput basis. Other products include slurry, light cycle oil, vacuum tower bottom, or VTB, reformer feeds, gas oil, pet coke

and sulfur. All of our pet coke by-product is consumed by the adjacent nitrogen fertilizer business, which enables the fertilizer plant to be cost effective, because pet coke is utilized in lieu of higher priced natural gas. Following completion of our present capital expenditure program we expect the Solomon complexity score to rise from 10.0 to 11.2.

The refinery consists of two crude units and two vacuum units. A vacuum unit is a secondary unit which processes crude oil by separating product from the crude unit according to boiling point under high heat and low pressure to recover various hydrocarbons. The availability of more than one crude and vacuum unit creates redundancy in the refinery system and enables us to continue to run the refinery even if one of these units were to shut down for scheduled or unscheduled plant maintenance and upgrades. However, the maximum combined capacity of the crude units is limited by the overall downstream capacity of the vacuum units and other units.

Our petroleum business also includes the following auxiliary operating assets:

Crude Oil Gathering System. We own and operate a 25,000 bpd crude oil gathering system comprised of over 300 miles of feeder and trunk pipelines, 40 trucks and associated storage facilities for gathering light, sweet Kansas and Oklahoma crude oils purchased from independent crude producers. We have also leased a section of a pipeline from Magellan Pipeline Company, L.P. that will allow us to gather additional volumes of attractively priced quality crudes.

Phillipsburg Terminal. We own storage and terminalling facilities for asphalt and refined fuels at Phillipsburg, Kansas. Our asphalt storage and terminalling facilities are used to receive, store and redeliver asphalt for another oil company for a fee pursuant to an asphalt services agreement.

Feedstocks Supply

Our refinery has the capability to process a blend of heavy sour as well as light sweet crudes. Currently, our refinery processes crude from a broad array of sources, approximately two-thirds domestic and one-third foreign. We purchase foreign crudes from Latin America, South America, West Africa, the North Sea and Canada. We purchase domestic crudes that meet pipeline specifications from Kansas, Oklahoma, Texas, and offshore deepwater Gulf of Mexico production. Given our refinery s ability to process a wide variety of crudes and ready access to multiple sources of crude, we have never curtailed production due to lack of crude access. Other feedstocks (petroleum products that are processed and blended into refined products) include natural gasoline, various grades of butanes, vacuum gas oil, vacuum tower bottom, or VTB, and others which are sourced from the Conway/Group 140 storage facility or regional refinery suppliers. Below is a summary of our historical feedstock inputs:

	Year Ended December 31,					Six Months Ended June 30,	
	2002	2003	2004	2005	2006	2006	2007
				(in barrels)			
Crude oil	27,172,830	31,207,718	33,227,971	33,250,518	34,501,288	17,028,988	12,868,722
Natural gasoline	1,093,629	483,362	317,874	455,587	373,667	163,371	48,996
Normal butane			530,575	467,176	483,131	163,116	135,680
Isobutane	1,037,855	1,627,989	1,615,898	1,398,694	1,460,893	745,698	380,111
Alky feed				68,636	170,542	24,796	14,075
Gas oil				155,344	425,319	189,744	69,272

Vacuum tower bottom	98,371	109,974	105,981	99,362	30,717	30,208	33,072
Total Inputs	29,402,685	33,429,043	35,798,299	35,895,317	37,445,557	18,345,921	13,549,928

Crude is supplied to our refinery through our wholly owned gathering system and by pipeline.

Our crude gathering system was expanded in 2006 and now supplies in excess of 22,000 bpd of crude to the refinery (approximately 20% of total supply). We leased a pipeline in 2006 from Magellan

Pipeline Company, L.P. that will serve as part of our pipeline system and will allow for further buying of attractively priced locally produced crudes. Locally produced crudes are delivered to the refinery at a discount to WTI and are of similar quality to WTI. These lighter sweet crudes allow us to blend higher percentages of low cost crudes such as heavy sour Canadian while maintaining our target medium sour blend with an API gravity of 28-32 degrees and 1-1.2% sulfur.

Crude oils sourced outside of our proprietary gathering system are first delivered by common carrier pipelines (primarily Seaway) into various terminals in Cushing, Oklahoma, where they are blended and then delivered to Caney, Kansas via a pipeline owned by Plains All American L.P. Crudes are delivered to our refinery from Caney, Kansas via a 145,000 bpd proprietary pipeline system, which we own. We also maintain capacity on the Spearhead Pipeline owned ultimately by Enbridge, and we have committed to additional pipeline capacity on the proposed Keystone pipeline project currently under development by TransCanada Keystone Pipeline, LP. As part of our crude supply optimization efforts, we lease approximately 1,550,000 barrels of crude oil storage in Cushing, and recently purchased 185 acres of land in the heart of the Cushing crude storage district, which we expect will provide us a storage expansion option should the addition of crude storage be required in the future.

The following table sets forth the feedstock pipelines used by the oil refinery as of June 30, 2007:

Pipeline	**Nominal Capacity (bpd)**
Seaway Pipeline (TEPPCO) from U.S. Gulf Coast to Cushing, Oklahoma	350,000
Spearhead (CCPS/Enbridge) from Griffith (Chicago) to Cushing, Oklahoma	125,000
Coffeyville Crude Oil Pipeline System from Caney, Kansas to Oil Refinery	145,000
Coffeyville Crude Oil Gathering and Trucking System	25,000
Natural Gas Liquid (NGL) Connection from/to Conway, Kansas through MAPCO and ONEOK	15,000
Plains-Cushing to Caney, Kansas	97,000
Sun Logistics Pipeline from U.S.G.C. to Cushing, Oklahoma	120,000

We purchase most of our crude oil requirements outside of our proprietary gathering system under a credit intermediation agreement with J. Aron. The credit intermediation agreement helps us reduce our inventory position and mitigate crude pricing risk. Once we identify cargos of crude oil and pricing terms that meet our requirements, we notify J. Aron which then provides, for a fee, credit, transportation and other logistical services for delivery of the crude to the crude oil tank farm. Generally, we select crude oil approximately 30 to 45 days in advance of the time the related refined products are to be marketed, except for Canadian and West African crude purchases which require an additional 30 days of lead time due to transit considerations.

Transportation Fuels

Gasoline. Gasoline typically accounts for approximately 43% of our refinery s production. Our oil refinery produces various grades of gasoline, ranging from 84 sub-octane regular unleaded to 91 octane premium unleaded and uses a computerized component blending system to optimize gasoline blending.

Distillates. Distillates typically account for approximately 44% of the refinery s production. The majority of the diesel fuel we produce is ultra low-sulfur.

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The following table summarizes our historical oil refinery yields:

	Year Ended December 31,					Six Months Ended June 30,	
	2002	2003	2004	2005	2006	2006	2007
			(in barrels)				
asoline:							
egular unleaded	14,071,304	16,531,362	16,703,566	16,154,172	16,836,946	8,382,403	5,737,930
remium unleaded	306,334	298,789	220,908	261,467	479,211	270,207	48,857
ub-octane unleaded	754,264	773,831	797,416	109,774	294,356	80,599	
otal gasoline	15,131,902	17,603,982	17,721,890	16,525,413	17,610,513	8,733,209	5,786,787
istillate:							
erosene	26,085	25,149	23,256	32,302	22,195	(5,542)	10,261
t fuel							
o. 1 distillate	124,741	342,363	99,832	261,048	319,920	3,272	37,266
o. 2 low sulfur stillate	6,526,883	7,899,132	8,896,701	9,129,518	11,583,942	5,599,539	5,789,899
o. 2 high sulfur stillate	2,268,116	3,017,785	3,500,351	3,916,658	3,441,683	2,031,624	
iesel	1,923,370	1,258,279	1,425,897	1,259,308	26,113	22,869	61,732
otal distillate	10,869,195	12,542,708	13,946,037	14,598,834	15,393,853	7,651,762	5,899,158
quid by-products:							
GL (propane, utane)	583,095	734,737	1,137,645	696,637	705,869	342,989	226,004
urry	445,784	532,236	500,692	562,657	706,332	375,492	225,119
ght cycle oil sales	84,146	42,571					
TB sales	8,212	26,438	150,700	134,899	74,979	25,949	
eformer feed sales			79,906	230,785	357,411	180,360	52,304
as oil sales	84,673			66,274			18,860
otal liquid -products	1,205,910	1,335,982	1,868,943	1,691,252	1,844,591	924,790	552,287
olid by-products:							
oke	2,068,031	1,956,619	2,384,414	2,439,297	2,491,867	1,273,412	877,611
ulfur	74,226	131,137	88,744	100,035	94,117	44,755	37,616
otal solid -products	2,142,257	2,087,756	2,473,158	2,539,332	2,585,984	1,318,167	915,227
GL production	52,682	(8,539)		548,883	519,986	218,419	284,959
process change	114,945	(120,122)	(12,369)	265,280	(243,553)	(307,639)	88,674
roduced fuel	1,268,388	1,489,030	1,636,665	1,557,689	1,719,345	812,823	638,648
rocessing loss (gain)	(1,382,594)	(1,501,754)	(1,836,025)	(1,831,366)	(1,985,162)	(1,005,610)	(585,812

otal yields	29,402,685	33,429,043	35,798,299	35,895,317	37,445,557	18,345,921	13,549,928

Our oil refinery s long-term capacity utilization (ratio of total refinery throughput to the refinery s rated capacity) has steadily improved over the years. To further enhance capacity utilization, our operations management initiatives and capital expenditures program are focused on improving crude slate flexibility, increasing inbound NGL pipeline capacity and optimizing use of raw materials and in-process feedstock.

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The following table summarizes storage capacity at the oil refinery as of June 30, 2007 which we believe is sufficient for our current needs:

Product	**Capacity (barrels)**
Gasoline	767,000
Distillates	1,068,000
Intermediates	1,004,000
Crude oil(1)	2,594,000

(1) Crude oil storage consists of 674,000 barrels of refinery storage capacity, 520,000 barrels of field storage capacity and 1,400,000 barrels of leased storage at Cushing, Oklahoma.

Distribution Pipelines and Product Terminals

We focus our marketing efforts on the midwestern states of Oklahoma, Kansas, Missouri, Nebraska, and Iowa for the sale of our petroleum products because of their relative proximity to our oil refinery and their pipeline access. Since the Subsequent Acquisition, we have significantly expanded our rack sales directly to the customers as opposed to origin bulk sales. Rack sales are sales which are made using tanker trucks via either a proprietary or third party terminal facility designed for truck loading. In contrast, bulk sales are sales made through pipelines. Approximately 23% of the refinery s products are sold through the rack system directly to retail and wholesale customers while the remaining 77% is sold through pipelines via bulk spot and term contracts.

We are able to distribute gasoline, diesel fuel, and natural gas liquids produced at the refinery either into the Magellan or Enterprise pipeline and further on through Valero and other Magellan systems or via the trucking system. The Magellan #2 and #3 pipelines are connected directly to the refinery and transport products to Kansas City and other northern cities. The Valero and Magellan (Mountain) pipelines are accessible via the Enterprise outbound line or through the Magellan system at El Dorado, Kansas. Our modern three-bay, bottom-loading fuels loading rack has been in service since July 1998 with a maximum delivery capability of 225 trucks per day or 40,000 bpd of finished gasoline and diesel fuels. We own and operate refined fuels and asphalt storage and terminalling facilities in Phillipsburg, Kansas. Our asphalt storage and terminalling facilities are used to receive, store and redeliver asphalt for another oil company for a fee pursuant to an asphalt services agreement. Our refined fuels truck terminal includes two loading locations with a capacity of approximately 95 trucks per day.

Below is a detailed summary of our product distribution pipelines and their capacities:

Pipeline	**Capacity (bpd)**
Magellan Pipeline #3-8 Line (from Coffeyville to northern cities via Caney, Kansas)	32,000
Magellan Pipeline #2-10 Line (from Coffeyville to northern cities via Barnsdall, Oklahoma)	81,000
Enterprise Pipeline (provides accessibility to Magellan (Mountain) and Valero systems at El Dorado, Kansas)	12,000
Truck Loading Rack Delivery System	40,000

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The following map depicts part of the Magellan pipeline, which the oil refinery uses for the majority of its distribution.

Source: Magellan Midstream Partners, L.P.

Nitrogen Fertilizer Business

The nitrogen fertilizer business operates the only nitrogen fertilizer plant in North America that utilizes a coke gasification process to generate hydrogen feedstock that is further converted to ammonia for the production of nitrogen fertilizers. The nitrogen fertilizer business is also considering a fertilizer plant expansion, which we estimate could increase the facility s capacity to upgrade ammonia into premium priced UAN by 50% to approximately 1,000,000 tons per year.

The facility uses a gasification process licensed from an affiliate of The General Electric Company, or General Electric, to convert pet coke to high purity hydrogen for subsequent conversion to ammonia. It uses between 950 to 1,050 tons per day of pet coke from the refinery and another 250 to 300 tons per day from unaffiliated, third-party sources such as other Midwestern refineries or pet coke brokers and converts it all to approximately 1,200 tons per day of ammonia. The fertilizer plant has demonstrated consistent levels of production at levels close to full capacity and has the following advantages compared to competing natural gas-based facilities:

Significantly Lower Cost Position. The coke gasification process allows the nitrogen fertilizer business to use less than 1% of the natural gas relative to other nitrogen based fertilizer facilities that are heavily dependent upon natural gas and are thus heavily impacted by natural gas price swings. Because the plant uses pet coke, the nitrogen fertilizer business has a significant cost advantage over other North American natural gas-based fertilizer producers. The adjacent refinery supplies on average more than 80% of the plant s raw material.

Strategic Location with Transportation Advantage. The nitrogen fertilizer business believes that selling products to customers in close proximity to the UAN plant and reducing transportation costs are keys to maintaining its profitability. Due to the plant s favorable location relative to end users and high product demand relative to production volume all of the product shipments are targeted to freight advantaged destinations located in the U.S. farm belt. The available ammonia production at the nitrogen fertilizer plant is small and easily sold into truck and rail delivery points. The products leave the plant either in trucks for direct shipment to customers or in railcars for principally Union Pacific Railroad destinations. The nitrogen fertilizer business does not incur any intermediate transfer, storage, barge freight or pipeline freight charges. Consequently, because these costs are not incurred, we estimate that the plant enjoys a distribution cost advantage over U.S. Gulf Coast ammonia and UAN importers, assuming in each case freight rates and pipeline tariffs for U.S. Gulf Coast importers as recently in effect.

High and Increased Capacity Utilization. The average capacity utilization has increased for the period 2005-June 2007 compared to 2002-2004. The average capacity utilization for the gasifier, ammonia and UAN for the period 2002-2004 were 87.0%, 75.5% and 89.9%, respectively, and for the period 2005-June 2007 were 94.4%, 94.9% and 117.2%, respectively. The gasifier on-stream factor is a measure of how long the gasifier has been operational over a period. We expect that efficiency of the plant will continue to improve with operator training, replacement of unreliable equipment, and reduced dependence on contract maintenance.

	Year Ended December 31,					Six Months Ended June 30,	
	2002	**2003**	**2004**	**2005**	**2006**	**2006**	**2007**
Gasifier on-stream(1)	78.6%	90.1%	92.4%	98.1%	92.5%	97.3%	90.6%
Ammonia capacity utilization(2)	66.0%	83.6%	76.8%	102.9%	92.0%	103.2%	84.9%
UAN capacity utilization(3)	79.4%	93.3%	97.0%	121.2%	115.6%	120.9%	112.2%

(1) On-stream factor is the total number of hours operated divided by the total number of hours in the reporting period.

(2) Based on nameplate capacity of 1,100 tons per day.

(3) Based on nameplate capacity of 1,500 tons per day.

Raw Material Supply

The nitrogen fertilizer facility s primary input is pet coke, of which more than 80% on average is supplied by our adjacent oil refinery at market prices. Historically the nitrogen fertilizer business has obtained a small amount of pet coke from third parties such as other Midwestern refineries or pet coke brokers at spot prices. We believe that optimization of the use of our oil refinery s coker should reduce the need for purchasing pet coke from third parties. In connection with the transfer of the nitrogen fertilizer business to the Partnership, we will enter into a 20-year coke supply agreement with the Partnership under which we will sell pet coke to the nitrogen fertilizer facility. If necessary, the gasifier can also operate on low grade coal, which provides an additional raw material source. There are significant supplies of low grade coal within a 60 mile radius of the plant.

The BOC Group owns, operates, and maintains the air separation plant that provides contract volumes of oxygen, nitrogen, and compressed dry air to the gasifier for a monthly fee. The nitrogen fertilizer business provides and pays for all utilities required for operation of the air separation plant. The air separation plant has not experienced any long-term operating problems. The nitrogen fertilizer plant is covered for business interruption insurance for up to $25 million in case of any interruption in the supply of oxygen from The BOC Group from a covered peril. The agreement with The BOC Group expires in 2020. The agreement also provides that if our requirements for liquid or gaseous oxygen, liquid or gaseous nitrogen or clean dry air exceed specified instantaneous flow rates by at least 10%, we can solicit bids from The BOC Group and third parties to supply our incremental product needs. We are required to provide notice to The BOC Group of the approximate quantity of excess product that we will need and the approximate date by which we will need it; we and The BOC Group will then jointly develop a request for proposal for soliciting bids from third parties and The BOC Group. The bidding procedures may be limited under specified circumstances.

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The nitrogen fertilizer business imports start-up steam for the fertilizer plant from our adjacent oil refinery, and then exports steam back to the oil refinery once all units are in service. Monthly charges and credits are booked with steam valued at the gas price for the month. In connection with the transfer of the nitrogen fertilizer business to the Partnership, we will enter into a feedstock and shared services agreement with the Partnership which will regulate among other things the import and export of start-up steam between the refinery and the fertilizer plant.

Production Process

The nitrogen fertilizer plant was built in 2000 with a pair of gasifiers to provide reliability. Following a turnaround completed in the second quarter of 2006, the plant is capable of processing approximately 1,300 tons per day of pet coke from the oil refinery and third-party sources and converting it into approximately 1,200 tons per day of ammonia. It uses a gasification process licensed from General Electric to convert the pet coke to high purity hydrogen for subsequent conversion to ammonia. A majority of the ammonia is converted to approximately 2,000 tons per day of UAN. Typically 0.41 tons of ammonia are required to produce one ton of UAN.

Pet coke is first ground and blended with water and a fluxant (a mixture of fly ash and sand) to form a slurry that is then pumped into the partial oxidation gasifier. The slurry is then contacted with oxygen from an air separation unit, or ASU. Partial oxidation reactions take place and the synthesis gas, or syngas, consisting predominantly of hydrogen and carbon monoxide, is formed. The mineral residue from the slurry is a molten slag (a glasslike substance containing the metal impurities originally present in coke) and flows along with the syngas into a quench chamber. The syngas and slag are rapidly cooled and the syngas is separated from the slag.

Slag becomes a by-product of the process. The syngas is scrubbed and saturated with moisture. The syngas next flows through a shift unit where the carbon monoxide in the syngas is reacted with the moisture to form hydrogen and carbon dioxide. The heat from this reaction generates saturated steam. This steam is combined with steam produced in the ammonia unit and the excess steam not consumed by the process is sent to the adjacent oil refinery.

After additional heat recovery, the high-pressure syngas is cooled and processed in the acid gas removal, or AGR, unit. The syngas is then fed to a pressure swing absorption, or PSA, unit, where the remaining impurities are extracted. The PSA unit reduces residual carbon monoxide and carbon dioxide levels to trace levels, and the moisture-free, high-purity hydrogen is sent directly to the ammonia synthesis loop.

The hydrogen is reacted with nitrogen from the ASU in the ammonia unit to form the ammonia product. A portion of the ammonia is converted to UAN.

The following is an illustrative Nitrogen Fertilizer Plant Process Flow Chart:

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Critical equipment is set up on routine maintenance schedules using the nitrogen fertilizer business own maintenance technicians. Pursuant to a Technical Services Agreement with General Electric, which licensed the gasification technology, General Electric experts provide technical advice and technological updates from their ongoing research as well as other licensees operating experiences.

The coke gasification process is licensed from General Electric Company pursuant to a license agreement that will be fully paid up as of June 1, 2007. The license grants the nitrogen fertilizer business perpetual rights to use the coke gasification process on specified terms and conditions. The license is important because it allows the nitrogen fertilizer facility to operate at a low cost compared to facilities which rely on natural gas.

Distribution

The primary geographic markets for the fertilizer products are Kansas, Missouri, Nebraska, Iowa, Illinois, and Texas. Ammonia products are marketed to industrial and agricultural customers and UAN products are marketed to agricultural customers. The direct application agricultural demand from the nitrogen fertilizer plant occurs in three main use periods. The summer wheat pre-plant occurs in August and September. The fall pre-plant occurs in late October and November. The highest level of ammonia demand is traditionally observed in the spring pre-plant period, from March through May. There are also small fill volumes that move in the off-season to fill the available storage at the dealer level.

Ammonia and UAN are distributed by truck or by railcar. If delivered by truck, products are sold on a freight-on-board basis, and freight is normally arranged by the customer. The nitrogen fertilizer business also owns and leases a fleet of railcars. It also negotiates with distributors that have their own leased railcars to utilize these assets to deliver products. The business owns all of the truck and rail loading equipment at the facility. It operates two truck loading and eight rail loading racks for each of ammonia and UAN.

Sales and Marketing

Petroleum Business

We focus our marketing efforts on the Midwestern states of Oklahoma, Kansas, Missouri, Nebraska, and Iowa and frequently Colorado, as economics dictate, for the sale of our petroleum products because of their relative proximity to our refinery and their pipeline access. Our refinery produces approximately 88,000 bpd of gasoline and distillates, which we estimate was approximately 10% of the demand for gasoline and distillates in our target market area in 2006.

Nitrogen Fertilizer Business

The primary geographic markets for the fertilizer products are Kansas, Missouri, Nebraska, Iowa, Illinois, and Texas. The nitrogen fertilizer business markets the ammonia products to industrial and agricultural customers and the UAN products to agricultural customers. The direct application agricultural demand from the nitrogen fertilizer plant occurs in three main use periods. The summer wheat pre-plant occurs in August and September. The fall pre-plant occurs in late October and in November. The highest level of ammonia demand is traditionally in the spring pre-plant period, from March through May. There are also small fill volumes that move in the off-season to fill the available storage at the dealer level.

The nitrogen fertilizer business markets agricultural products to destinations that produce the best margins for the business. These markets are primarily located on the Union Pacific railroad or destinations which can be supplied by truck. By securing this business directly, the nitrogen fertilizer business reduces its dependence on distributors serving the same customer base, which enables it to capture a larger margin and allows it to better control its product distribution. Most of the agricultural sales are made on a competitive spot basis. The nitrogen fertilizer business also offers products on a prepay basis for in-season demand. The heavy in-season demand periods are spring and fall in the corn belt and summer in the wheat belt. The corn belt is the primary corn producing region of the

United States, which includes Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Ohio and Wisconsin. The wheat belt is the primary wheat producing region of the United States, which includes Oklahoma, Kansas, North Dakota, South Dakota and Texas. Some of the industrial sales are spot sales, but most are on annual or multiyear contracts. Industrial demand for ammonia provides consistent sales and allows the nitrogen fertilizer business to better manage inventory control and generate consistent cash flow.

Customers

Petroleum Business

Customers for our petroleum products include other refiners, convenience store companies, railroads and farm cooperatives. We have bulk term contracts in place with most of these customers, which typically extend from a few months to one year in length. Our shipments to these customers are typically in the 10,000 to 60,000 barrel range (420,000 to 2,520,000 gallons) and are delivered by pipeline. We enter into these types of contracts in order to lock in a committed volume at market prices to ensure an outlet for our refinery production. For the year ended December 31, 2005, CHS Inc., SemFuel LP, QuikTrip Corporation and GROWMARK, Inc. accounted for 16.2%, 15.9%, 15.8% and 10.8%, respectively, of our petroleum business sales and for the year ended December 31, 2006, they accounted for 2.0%, 10.0%, 15.5% and 10.0%, respectively. For the six months ended June 30, 2007, they accounted for 2.6%, 5.9%, 12.1% and 8.5%, respectively, of our petroleum business sales. We sell bulk products based on industry market related indexes such as Platt s or NYMEX related Group Market (Midwest) prices.

In addition to bulk sales, we have implemented an aggressive truck rack marketing initiative. Utilizing the Magellan pipeline system we are able to sell in truckload quantities to customers such as convenience store chains, truck stops, jobbers, railroads, and commercial and industrial end users. Truck rack sales are at daily posted prices which are influenced by the NYMEX, competitor pricing and group spot market differentials. Rack prices are generally higher than bulk prices.

Nitrogen Fertilizer Business

The nitrogen fertilizer business sells ammonia to agricultural and industrial customers. It sells approximately 80% of the ammonia it produces to agricultural customers, such as farmers in the mid-continent area between North Texas and Canada, and approximately 20% to industrial customers. Agricultural customers include distributors such as MFA, United Suppliers, Inc., Brandt Consolidated Inc., ConAgra Fertilizer Interchem, and Agriliance, LLC. Industrial customers include Tessenderlo Kerley, Inc. and National Cooperative Refinery Association. The nitrogen fertilizer business sells UAN products to retailers and distributors. For the year ended December 31, 2005 and the year ended December 31, 2006 and for the six months ended June 30, 2007, the top five ammonia customers in the aggregate represented 55.2%, 51.9% and 74.3% of the business s ammonia sales, respectively, and the top five UAN customers in the aggregate represented 43.1%, 30.0% and 38.8% of the business s UAN sales, respectively. During the year ended December 31, 2005, Brandt Consolidated Inc. and MFA accounted for 23.3% and 13.6% of the business s ammonia sales, respectively, and Agriliance and ConAgra Fertilizer accounted for 14.7% and 12.7% of its UAN sales, respectively. During the year ended December 31, 2006, Brandt Consolidated Inc. and MFA accounted for 22.2% and 13.1% of the business s ammonia sales, respectively, and ConAgra Fertilizer and Agriliance accounted for 8.4% and 6.3% of its UAN sales, respectively. During the six months ended June 30, 2007, Brandt Consolidated Inc. and MFA accounted for 20.1% and 20.8% of the business s ammonia sales, respectively and ConAgra Fertilizer and Interchem accounted for 19.5% and 8.6% of its UAN sales, respectively.

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Competition

We have experienced and expect to continue to meet significant levels of competition from current and potential competitors, many of whom have significantly greater financial and other resources. See Risk Factors Risks Related to Our Petroleum Business We face significant competition, both within and outside of our industry. Competitors who produce their own supply of feedstocks, have extensive retail outlets, make alternative fuels or have greater financial resources than we do may have a competitive advantage over us and Risk Factors Risks Related to The Nitrogen Fertilizer Business Fertilizer products are global commodities, and the nitrogen fertilizer business faces intense competition from other nitrogen fertilizer producers.

Petroleum Business

Our oil refinery in Coffeyville, Kansas ranks second in processing capacity and fifth in refinery complexity, among the seven mid-continent fuels refineries. The following table presents certain information about us and the six other major mid-continent fuel oil refineries with which we compete:

Company	Location	Crude Capacity (barrels per calendar day)	Solomon Complexity Index
ConocoPhillips	Ponca City, OK	187,000	12.5
CVR Energy	Coffeyville, KS	113,500	10.0
Frontier Oil	El Dorado, KS	110,000	13.3
Valero	Ardmore, OK	88,000	11.3
NCRA	McPherson, KS	82,200	14.1
Gary Williams Energy	Wynnewood, OK	52,500	8.0
Sinclair	Tulsa, OK	50,000	8.3
Mid-continent Total:		677,700	

Source: Oil and Gas Journal. A Sunoco refinery located in Tulsa, Oklahoma was excluded from this table because it is not a stand-alone fuels refinery. The Solomon Complexity Index of each of these facilities has been calculated based on data from the Oil and Gas Journal together with Company estimates and assumptions.

We compete with our competitors primarily on the basis of price, reliability of supply, availability of multiple grades of products and location. The principal competitive factors affecting our refining operations are costs of crude oil and other feedstock costs, refinery complexity (a measure of a refinery s ability to convert lower cost heavy and sour crudes into greater volumes of higher valued refined products such as gasoline), refinery efficiency, refinery product mix and product distribution and transportation costs. The location of our refinery provides us with a reliable supply of crude oil and a transportation cost advantage over our competitors.

Our competitors include trading companies such as SemFuel, L.P., Western Petroleum, Center Oil, Tauber Oil Company, Morgan Stanley and others. In addition to competing refineries located in the mid-continent United States, our oil refinery also competes with other refineries located outside the region that are linked to the mid-continent market through an extensive product pipeline system. These competitors include refineries located near the U.S. Gulf Coast and the Texas Panhandle region.

Our refinery competition also includes branded, integrated and independent oil refining companies such as BP, Shell, ConocoPhillips, Valero, Sunoco and Citgo, whose strengths include their size and access to capital. Their branded stations give them a stable outlet for refinery production although the branded strategy requires more working capital and a much more expensive marketing organization.

Nitrogen Fertilizer Business

Competition in the nitrogen fertilizer industry is dominated by price considerations. However, during the spring and fall application seasons, farming activities intensify and delivery capacity is a significant competitive factor. The nitrogen fertilizer plant maintains a large fleet of rail cars and seasonally adjusts inventory to enhance its manufacturing and distribution operations.

Domestic competition, mainly from regional cooperatives and integrated multinational fertilizer companies, is intense due to customers sophisticated buying tendencies and production strategies that focus on cost and service. Also, foreign competition exists from producers of fertilizer products manufactured in countries with lower cost natural gas supplies. In certain cases, foreign producers of fertilizer who export to the United States may be subsidized by their respective governments. The nitrogen fertilizer business major competitors include Koch Nitrogen, PCS, Terra and CF Industries, all of which produce more UAN than we do.

The nitrogen fertilizer plant s main competition in ammonia marketing are Koch s plants at Beatrice, Nebraska, Dodge City, Kansas and Enid, Oklahoma, as well as Terra s plants in Verdigris and Woodward, Oklahoma and Port Neal, Iowa.

Based on Blue Johnson data regarding total U.S. demand for UAN and ammonia, we estimate that the nitrogen fertilizer plant s UAN production in 2005 represented approximately 5.5% of the total U.S. demand and that the net ammonia produced and marketed at Coffeyville represents less than 1% of the total U.S. demand.

Seasonality

Petroleum Business

Our petroleum business experiences seasonal effects as demand for gasoline products is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic and road construction work. Demand for diesel fuel during the winter months also decreases due to agricultural work declines during the winter months. As a result, our results of operations for the first and fourth calendar quarters are generally lower than for those for the second and third calendar quarters. In addition, unseasonably cool weather in the summer months and/or unseasonably warm weather in the winter months in the markets in which we sell our petroleum products can reduce demand for gasoline and diesel fuel.

Nitrogen Fertilizer Business

A significant portion of nitrogen fertilizer product sales consists of sales of agricultural commodity products, exposing the business to seasonal fluctuations in demand for nitrogen fertilizer products in the agricultural industry. As a result, the nitrogen fertilizer business typically generates greater net sales and operating income in the spring. In addition, the demand for fertilizers is affected by the aggregate crop planting decisions and fertilizer application rate decisions of individual farmers who make planting decisions based largely on the prospective profitability of a harvest. The specific varieties and amounts of fertilizer they apply depend on factors like crop prices, their current liquidity, soil conditions, weather patterns and the types of crops planted.

Environmental Matters

The petroleum and nitrogen fertilizer businesses are subject to extensive and frequently changing federal, state and local laws and regulations relating to the protection of the environment. These laws, their underlying regulatory requirements and the enforcement thereof impact our petroleum business and operations and the nitrogen fertilizer business by imposing:

restrictions on operations and/or the need to install enhanced or additional controls;

the need to obtain and comply with permits and authorizations;

liability for the investigation and remediation of contaminated soil and groundwater at current and former facilities and off-site waste disposal locations; and

specifications for the products marketed by our petroleum business and the nitrogen fertilizer business, primarily gasoline, diesel fuel, UAN and ammonia.

The petroleum refining industry is subject to frequent public and governmental scrutiny of its environmental compliance. As a result, the laws and regulations to which we are subject are often evolving and many of them have become more stringent or become subject to more stringent interpretation or enforcement by federal and state agencies. The ultimate impact of complying with existing laws and regulations is not always clearly known or determinable due in part to the fact that our operations may change over time and certain implementing regulations for laws such as the Resource Conservation and Recovery Act, or the RCRA, and the Clean Air Act have not yet been finalized, are under governmental or judicial review or are being revised. These regulations and other new air and water quality standards and stricter fuel regulations could result in increased capital, operating and compliance costs.

The principal environmental risks associated with our petroleum operations and the nitrogen fertilizer business are air emissions, releases of hazardous substances into the environment, and the treatment and discharge of wastewater. The legislative and regulatory programs that affect these areas are outlined below. For a discussion of the environmental impact of the flood and crude oil discharge, see Flood and Crude Oil Discharge Crude Oil Discharge and Flood and Crude Oil Discharge EPA Administrative Order on Consent.

The Clean Air Act

The Clean Air Act and its underlying regulations as well as the corresponding state laws and regulations that regulate emissions of pollutants into the air affect our petroleum operations and the nitrogen fertilizer business both directly and indirectly. Direct impacts may occur through Clean Air Act permitting requirements and/or emission control requirements relating to specific air pollutants. The Clean Air Act indirectly affects our petroleum operations and the nitrogen fertilizer business by extensively regulating the air emissions of sulfur dioxide, or SO_2, volatile organic compounds, nitrogen oxides and other compounds including those emitted by mobile sources, which are direct or indirect users of our products.

The Clean Air Act imposes stringent limits on air emissions, establishes a federally mandated permit program and authorizes civil and criminal sanctions and injunctions for any failure to comply. The Clean Air Act also establishes National Ambient Air Quality Standards, or NAAQS, that states must attain. If a state cannot attain the NAAQS (i.e., is in nonattainment), the state will be required to reduce air emissions to bring the state into attainment. A geographic area s attainment status is based on the severity of air pollution. A change in the attainment status in the area where our facilities are located could necessitate the installation of additional controls. At the current time, all areas where our petroleum business and the nitrogen fertilizer business operate in are classified as attainment for NAAQS.

There have been numerous other recently promulgated National Emission Standards for Hazardous Air Pollutants, NESHAP or MACT, including, but not limited to, the Organic Liquid Distribution MACT, the Miscellaneous Organic NESHAP, Gasoline Distribution Facilities MACT, Reciprocating Internal Combustion Engines MACT, Asphalt Processing MACT, Commercial and Institutional Boilers and Process Heaters standards. Some or all of these MACT standards or future promulgations of MACT standards may require the installation of controls or changes to our petroleum operations or the nitrogen fertilizer facilities in order to comply. If new controls or changes to operations are needed, the costs could be significant. These new requirements, other requirements of the Clean Air Act, or other presently existing or future environmental regulations could cause us to expend substantial amounts to comply and/or permit our refinery to produce products that meet applicable requirements.

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Air Emissions. The regulation of air emissions under the Clean Air Act requires us to obtain various operating permits and to incur capital expenditures for the installation of certain air pollution control devices at our refinery. Various regulations specific to, or that directly impact, our industry have been implemented, including regulations that seek to reduce emissions from refineries flare systems, sulfur plants, large heaters and boilers, fugitive emission sources and wastewater treatment systems. Some of the applicable programs are the Benzene Waste Operations NESHAP, New Source Performance Standards, New Source Review, and Leak Detection and Repair. We have incurred, and expect to continue to incur, substantial capital expenditures to maintain compliance with these and other air emission regulations.

In March 2004, we entered into a Consent Decree with the EPA and the KDHE to resolve air compliance concerns raised by the EPA and KDHE related to Farmland s prior operation of our oil refinery. Under the Consent Decree, we agreed to install controls on certain process equipment and make certain operational changes at our refinery. As a result of our agreement to install certain controls and implement certain operational changes, the EPA and KDHE agreed not to impose civil penalties, and provided a release from liability for Farmland s alleged noncompliance with the issues addressed by the Consent Decree. Pursuant to the Consent Decree, in the short term, we have increased the use of catalyst additives to the fluid catalytic cracking unit at the facility to reduce emissions of SO_2. We will begin adding catalyst to reduce oxides of nitrogen, or NOx, in 2007. In the long term, we will install controls to minimize both SO_2 and NOx emissions, which under terms of the Consent Decree require that final controls be in place by January 1, 2011. In addition, pursuant to the Consent Decree, we assumed certain cleanup obligations at the Coffeyville refinery and the Phillipsburg terminal. We agreed to retrofit certain heaters at the refinery with Ultra Low NOx burners. All heater retrofits have been performed and we are currently verifying that the heaters meet the Ultra Low NOx standards required by the Consent Decree. The Ultra Low NOx heater technology is in widespread use throughout the industry. There are other permitting, monitoring, record-keeping and reporting requirements associated with the Consent Decree. The overall cost of complying with the Consent Decree is expected to be approximately $41 million, of which approximately $35 million is expected to be capital expenditures and which does not include the cleanup obligations. No penalties are expected to be imposed as a result of the Consent Decree.

The EPA recently embarked on a Petroleum Refining Initiative alleging industry-wide noncompliance with four marquee issues: New Source Review, flaring, leak detection and repair, and Benzene Waste Operations NESHAP. The Petroleum Refining Initiative has resulted in many refiners entering into consent decrees imposing civil penalties and requiring substantial expenditures for additional or enhanced pollution control. At this time, we do not know how, if at all, the Petroleum Refining Initiative will affect us as our current Consent Decree covers some, but not all, of the marquee issues.

Fertilizer Plant Audit. The nitrogen fertilizer business conducted an air permitting compliance audit of its fertilizer plant pursuant to agreements with EPA and KDHE immediately after Immediate Predecessor acquired the fertilizer plant in 2004. The audit revealed that the fertilizer plant was not properly permitted under the Clean Air Act and its implementing regulations and corresponding Kansas environmental statutes and regulations. As a result, the fertilizer plant performed air modeling to demonstrate that the current emissions from the facility are in compliance with federal and state air quality standards, and that the air pollution controls that are in place are the controls that are required to be in place. The EPA and KDHE have finalized the permit for public notice without any requirement for additional equipment. The nitrogen fertilizer business will amend its Title V air operating permit application that will include the relevant terms and conditions of the new air permit.

Air Permitting. The petroleum refinery is a major source of air emissions under the Title V permitting program of the federal Clean Air Act. A final Class I (major source) operating permit was issued for our oil refinery in August 2006. We are currently in the process of amending the Title V permit to include the recently approved expansion project permit and the continuous catalytic reformer permit.

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The fertilizer plant has agreed to file a new Title V operating air permit application because the voluntary fertilizer plant audit (described in more detail above) revealed that the fertilizer plant should be permitted as a major source of certain air pollutants. In the meantime, the fertilizer plant is operating under the Clean Air Act s application shield (which protects permittees from enforcement while an operating permit is being issued as long as the permittee complies with the permit conditions contained in the permit application), the current construction permits, other KDHE approvals and the protections of the federal and state audit policies. The nitrogen fertilizer plant will amend its Title V permit application that will contain all terms and conditions imposed under the new permit and any other permits and/or approvals in place. We do not anticipate significant cost or difficulty in obtaining these permits. However, in the event that the EPA or KDHE determines that additional controls are required, the nitrogen fertilizer business may incur significant expenditures to comply.

We believe that we hold all material air permits required to operate the Phillipsburg Terminal and our crude oil transportation company s facilities.

Release Reporting

The release of hazardous substances or extremely hazardous substances into the environment is subject to release reporting of threshold quantities under federal and state environmental laws. Our petroleum operations and the nitrogen fertilizer business periodically experience releases of hazardous substances and extremely hazardous substances that could cause our petroleum business and/or the nitrogen fertilizer business to become the subject of a government enforcement action or third-party claims. We and the nitrogen fertilizer business report such releases promptly to federal and state environmental agencies.

Prior to the acquisition of the nitrogen fertilizer plant by Immediate Predecessor in 2004 and during the period the plant was owned by Immediate Predecessor, the facility experienced heat exchanger equipment deterioration at an unanticipated rate, resulting in upset/malfunction air releases of ammonia into the environment. The equipment was replaced in August 2004 with a new metallurgy design that also experienced an unanticipated deterioration rate. The new equipment was subsequently replaced in 2005 by a redesigned exchanger with upgraded metallurgy, which has operated without additional ammonia emissions. Other critical exchanger metallurgy was upgraded during the facility s most recent July 2006 turnaround. We have reported the excess emissions of ammonia to EPA and KDHE as part of an air permitting audit of the facility. Additional equipment, repairs to existing equipment, changes to current operations, government enforcement or third-party claims could result in significant expenditures and liability.

Fuel Regulations

Tier II, Low Sulfur Fuels. The EPA interprets the Clean Air Act to authorize the EPA to require modifications in the formulation of the refined transportation fuel products we manufacture in order to limit the emissions associated with their final use. The EPA believes such limits are necessary to protect new automobile emission control systems that may be inhibited by sulfur in the fuel. For example, in February 2000, EPA promulgated the Tier II Motor Vehicle Emission Standards Final Rule for all passenger vehicles, establishing standards for sulfur content in gasoline. These regulations mandate that the sulfur content of gasoline at any refinery shall not exceed 30 ppm during any calendar year beginning January 1, 2006. Such compliant gasoline is referred to as Ultra Low Sulfur Gasoline, or ULSG. Phase-in of these requirements began during 2004. In addition, in January 2001, EPA promulgated its on-road diesel regulations, which required a 97% reduction in the sulfur content of diesel sold for highway use by June 1, 2006, with full compliance by January 1, 2010. EPA adopted a rule for off-road diesel in May 2004. The off-road diesel regulations will generally require a 97% reduction in the sulfur content of diesel sold for off-road use by June 1, 2010. Such compliant diesel is referred to as Ultra Low Sulfur Diesel, or ULSD. We believe that our production of ULSG and ULSD will make us eligible for significant tax benefits in 2007 and 2008.

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Modifications will be required at our refinery as a result of the Tier II gasoline and low sulfur diesel standards. In February 2004 EPA granted us approval under a hardship waiver that would defer meeting final low sulfur Tier II gasoline standards until January 1, 2011 in exchange for our meeting low sulfur highway diesel requirements by January 1, 2007. We are currently in the startup phase of our Ultra Low Sulfur Diesel Hydrodesulfurization unit, which utilizes technology with widespread use throughout the industry. Compliance with the Tier II gasoline and on-road diesel standards required us to spend approximately $133 million during 2006 and we estimate that compliance will require us to spend approximately $108 million during 2007 and approximately $57 million between 2008 and 2010.

Methyl Tertiary Butyl Ether (MTBE). The EPA previously required gasoline to contain a specified amount of oxygen in certain regions that exceed the National Ambient Air Quality Standards for either ozone or carbon monoxide. This oxygen requirement had been satisfied by adding to gasoline one of many oxygen-containing materials including, among others, methyl tertiary butyl ether, or MTBE. As a result of growing public concern regarding possible groundwater contamination resulting from the use of MTBE as a source of required oxygen in gasoline, MTBE has been banned for use as a gasoline additive. Neither we nor, to the best of our knowledge, the Successor, the Immediate Predecessor or Farmland used MTBE in our petroleum products. We cannot make any assurance as to whether MTBE was added to our petroleum products after those products left our facilities or whether MTBE-containing products were distributed through our pipelines.

The Clean Water Act

The federal Clean Water Act of 1972 affects our petroleum operations and the nitrogen fertilizer business by regulating the treatment of wastewater and imposing restrictions on effluent discharge into, or impacting, navigable water. Regular monitoring, reporting requirements and performance standards are preconditions for the issuance and renewal of permits governing the discharge of pollutants into water. The petroleum and nitrogen fertilizer businesses maintain numerous discharge permits as required under the National Pollutant Discharge Elimination System program of the Clean Water Act and have implemented internal programs to oversee our compliance efforts.

All of our facilities and the facilities of the nitrogen fertilizer business are subject to Spill Prevention, Control and Countermeasures, or SPCC, requirements under the Clean Water Act. The SPCC rules were modified in 2002 with the modifications to go into effect in 2004. In 2004, certain requirements of the rule were extended. Changes to our operations may be required to comply with the modified SPCC rule.

In addition, we are regulated under the Oil Pollution Act. Among other requirements, the Oil Pollution Act requires the owner or operator of a tank vessel or facility to maintain an emergency oil response plan to respond to releases of oil or hazardous substances. We have developed and implemented such a plan for each of our facilities covered by the Oil Pollution Act. Also, in case of such releases, the Oil Pollution Act requires responsible parties to pay the resulting removal costs and damages, provides for substantial civil penalties, and authorizes the imposition of criminal and civil sanctions for violations. States where we have operations have laws similar to the Oil Pollution Act.

Wastewater Management. We have a wastewater treatment plant at our refinery permitted to handle an average flow of 2.2 million gallons per day. The facility uses a complete mix activated sludge, or CMAS, system with three CMAS basins. The plant operates pursuant to a KDHE permit. We are also implementing a comprehensive spill response plan in accordance with the EPA rules and guidance.

Ongoing fuels terminal and asphalt plant operations at Phillipsburg generate only limited wastewater flows (e.g., boiler blowdown, asphalt loading rack condensate, groundwater treatment). These flows are handled in a wastewater treatment plant that includes a primary clarifier, aerated secondary clarifier, and a final clarifier to a lagoon system.

The plant operates pursuant to a KDHE Water Pollution Control Permit. To control facility runoff, management implements a comprehensive Spill Response Plan. Phillipsburg also has a timely and current application on file with the KDHE for a separate storm water control permit.

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Resource Conservation and Recovery Act (RCRA)

Our operations are subject to the RCRA requirements for the generation, treatment, storage and disposal of hazardous wastes. When feasible, RCRA materials are recycled instead of being disposed of on-site or off-site. RCRA establishes standards for the management of solid and hazardous wastes. Besides governing current waste disposal practices, RCRA also addresses the environmental effects of certain past waste disposal operations, the recycling of wastes and the regulation of underground storage tanks containing regulated substances.

Waste Management. There are two closed hazardous waste units at the refinery and eight other hazardous waste units in the process of being closed pending state agency approval. In addition, one closed interim status hazardous waste landfarm located at the Phillipsburg terminal is under long-term post closure care.

We have set aside approximately $3.2 million in financial assurance for closure/post-closure care for hazardous waste management units at the Phillipsburg terminal and the Coffeyville refinery.

Impacts of Past Manufacturing. We are subject to a 1994 EPA administrative order related to investigation of possible past releases of hazardous materials to the environment at the Coffeyville refinery. In accordance with the order, we have documented existing soil and ground water conditions, which require investigation or remediation projects. The Phillipsburg terminal is subject to a 1996 EPA administrative order related to investigation of possible past releases of hazardous materials to the environment at the Phillipsburg terminal, which operated as a refinery until 1991. The Consent Decree that we signed with EPA and KDHE requires us to complete all activities in accordance with federal and state rules.

The anticipated remediation costs through 2011 were estimated, as of June 30, 2007, to be as follows (in millions):

Facility	Site Investigation Costs	Capital Costs	Total O&M Costs Through 2011	Total Estimated Costs Through 2011
Coffeyville Oil Refinery	$ 0.3	$	$ 0.6	$ 0.9
Phillipsburg Terminal	0.4		1.6	2.0
Total Estimated Costs	$ 0.7	$	$ 2.2	$ 2.9

These estimates are based on current information and could go up or down as additional information becomes available through our ongoing remediation and investigation activities. At this point, we have estimated that, over ten years, we will spend between $5.4 and $6.8 million to remedy impacts from past manufacturing activity at the Coffeyville refinery and to address existing soil and groundwater contamination at the Phillipsburg terminal. It is possible that additional costs will be required after this ten year period.

Environmental Insurance. We have entered into environmental insurance policies as part of our overall risk management strategy. Our primary pollution legal liability policy provides us with an aggregate limit of $25.0 million subject to a $5.0 million self-insured retention. This policy covers cleanup costs resulting from pre-existing or new pollution conditions and bodily injury and property damage resulting from pollution conditions. It also includes a $25.0 million business interruption sub-limit subject to a 45-day waiting period. Our excess pollution legal liability policy provides us with an additional $25.0 million of aggregate limit. The excess pollution legal liability policy does not provide coverage until the $25.0 million of underlying limit available in the primary pollution legal liability policy has been exhausted. We also have a financial assurance policy linked to our pollution legal liability policy that provides a $4.0 million limit per pollution incident and an $8.0 million aggregate policy limit related specifically to closed RCRA units at the Coffeyville refinery and the Phillipsburg terminal. Each of these policies contains substantial exclusions; as such, we cannot guarantee that we will have coverage for all or any particular liabilities. For a discussion of our insurance policies that relate to coverage for the flood and crude oil discharge, see Flood and Crude Oil Discharge Insurance.

Financial Assurance. We were required in the Consent Decree to establish $15 million in financial assurance to cover the projected cleanup costs posed by the Coffeyville and Phillipsburg facilities in the event our company failed to fulfill its clean-up obligations. In accordance with the Consent Decree, this financial assurance is currently provided by a bond posted by Original Predecessor, Farmland. We will be required to replace the financial assurance currently provided by Farmland and have so replaced approximately $3.4 million to date. At this point, it is not clear what the amount of financial assurance will be when replaced. Although it may be significant, it will not be more than $15 million.

Environmental Remediation

Under the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, RCRA, and related state laws, certain persons may be liable for the release or threatened release of hazardous substances. These persons include the current owner or operator of property where a release or threatened release occurred, any persons who owned or operated the property when the release occurred, and any persons who disposed of, or arranged for the disposal of, hazardous substances at a contaminated property. Liability under CERCLA is strict, retroactive and joint and several, so that any responsible party may be held liable for the entire cost of investigating and remediating the release of hazardous substances. The liability of a party is determined by the cost of investigation and remediation, the portion of the hazardous substance(s) the party contributed, the number of solvent potentially responsible parties, and other factors.

As is the case with all companies engaged in similar industries, we face potential exposure from future claims and lawsuits involving environmental matters. These matters include soil and water contamination, personal injury and property damage allegedly caused by hazardous substances which we, or potentially Farmland, manufactured, handled, used, stored, transported, spilled, released or disposed of. We cannot assure you that we will not become involved in future proceedings related to our release of hazardous or extremely hazardous substances or that, if we were held responsible for damages in any existing or future proceedings, such costs would be covered by insurance or would not be material.

Safety and Health Matters

We operate a comprehensive safety program, involving active participation of employees at all levels of the organization. We measure our success in this area primarily through the use of injury frequency rates administered by the Occupational Safety and Health Administration, or OSHA. In 2006, our oil refinery experienced a 92% reduction in injury frequency rates and the nitrogen fertilizer plant experienced a 24% reduction in such rate as compared to the average of the previous three years. The recordable injury rate reflects the number of recordable incidents (injuries as defined by OSHA) per 200,000 hours worked, and for the year ended December 31, 2006, we had a recordable injury rate of 0.30 in our petroleum business and 4.90 in the nitrogen fertilizer business. In 2006, our refinery achieved one year worked without a lost-time accident, which based on available records, had never been achieved in the 100 year history of the facility. In March 2007 our petroleum business achieved a milestone after operating for 1,000,000 consecutive man hours without a lost-time accident, and as of June 2007, our nitrogen fertilizer business had operated for 8 months without a lost-time accident. Our recordable injury rate for all business units was 0.28 for the period from January 2007 to June 2007. Despite our efforts to achieve excellence in our safety and health performance, we cannot assure you that there will not be accidents resulting in injuries or even fatalities. We have implemented a new incident investigation program that is intended to improve the safety for our employees by identifying the root cause of accidents and potential accidents and by correcting conditions that could cause or contribute to accidents or injuries. We routinely audit our programs and consider improvements in our management systems.

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Process Safety Management. We maintain a Process Safety Management program. This program is designed to address all facets associated with OSHA guidelines for developing and maintaining a Process Safety Management program. We will continue to audit our programs and consider improvements in our management systems.

We have evaluated and continue to implement improvements at our refinery s process units, underground process piping and emergency isolation valves for control of process flows. We currently estimate the costs for implementing any recommended improvements to be between $7 and $9 million over a period of four years. These improvements, if warranted, would be intended to reduce the risk of releases, spills, discharges, leaks, accidents, fires or other events and minimize the potential effects thereof. We are currently completing the addition of a new $27 million refinery flare system that will replace atmospheric sumps in our refinery. We are also assessing the potential impacts on building occupancy caused by the location and design of our refinery and fertilizer plant control rooms and operator shelters. We expect the costs to upgrade or relocate these areas to be between $4 and $6 million over two to five years. The current plan would consolidate the refinery control boards and equipment into a central control building that would also house operations and technical personnel and would lead to improved communication and efficiency for operation of the refinery.

Emergency Planning and Response. We have an emergency response plan that describes the organization, responsibilities and plans for responding to emergencies in the facilities. This plan is communicated to local regulatory and community groups. We have on-site warning siren systems and personal radios. We will continue to audit our programs and consider improvements in our management systems and equipment.

Community Advisory Panel (CAP). We developed and continue to support ongoing discussions with the community to share information about our operations and future plans. Our CAP includes wide representation of residents, business owners and local elected representatives for the city and county.

Employees

As of June 30, 2007, 415 employees were employed in our petroleum business, 109 were employed by the nitrogen fertilizer business and 59 employees were employed at our offices in Sugar Land, Texas and Kansas City, Kansas.

We entered into collective bargaining agreements which cover approximately 39% of our employees (all of whom work in our petroleum business) with the Metal Trades Union and the United Steelworkers of America, which expire in March 2009. We believe that our relationship with our employees is good.

Prior to the consummation of this offering, we will enter into a services agreement with the Partnership and the managing general partner of the Partnership pursuant to which we will provide certain management and other services to the Partnership, the managing general partner of the Partnership, and the Partnership s nitrogen fertilizer business. The services we will provide under the agreement include the following services, among others:

- services by our employees in capacities equivalent to the capacities of corporate executive officers, except that those who serve in such capacities under the agreement shall serve the Partnership on a shared, part-time basis only, unless we and the Partnership agree otherwise;

- administrative and professional services, including legal, accounting services, human resources, insurance, tax, credit, finance, government affairs and regulatory affairs;

- managing the property of the Partnership and Coffeyville Resources Nitrogen Fertilizers, LLC, a subsidiary of the Partnership, in the ordinary course of business;

recommending capital raising activities to the board of directors of the managing general partner of the Partnership including the issuance of debt or equity securities, the entry into credit facilities and other capital market transactions;

managing or overseeing litigation and administrative or regulatory proceedings, and establishing appropriate insurance policies for the Partnership, and providing safety and environmental advice;

recommending the payment of dividends or other distributions on equity securities; and

managing or providing advice for other projects as may be agreed by us and the managing general partner of the Partnership from time to time.

It is expected that the employees who will manage the nitrogen fertilizer business will remain at CVR Energy and their services will be provided to the Partnership pursuant to the services agreement. As a result, certain of our employees may be employed on a full-time or part-time basis to conduct the day-to-day business operations of the Partnership and the nitrogen fertilizer business. However, personnel performing the actual day-to-day business and operations of the Partnership at the plant level will be employed directly by the Partnership and its subsidiaries, which will bear all personnel costs for these employees. For more information on this services agreement, see The Nitrogen Fertilizer Limited Partnership Other Intercompany Agreements.

Properties

Our executive offices are located at 2277 Plaza Drive in Sugar Land, Texas. We lease approximately 22,000 square feet at that location. Rent under the lease is currently approximately $515,000 annually, plus operating expenses, increasing to approximately $550,000 in 2009. The lease expires in 2011. The following table contains certain information regarding our other principal properties

Location	Acres	Own/Lease	Use
Coffeyville, KS	440	Own	Oil refinery, fertilizer plant and office buildings
Phillipsburg, KS	200	Own	Terminal facility
Montgomery County, KS (Coffeyville Station)	20	Own	Crude oil storage
Montgomery County, KS (Broome Station)	20	Own	Crude oil storage
Bartlesville, OK	25	Own	Truck storage and office buildings
Winfield, KS	5	Own	Truck storage
Cushing, OK	185	Own	Crude oil storage
Cowley County, KS (Hooser Station)	80	Own	Crude oil storage
Holdrege, NE	7	Own	Crude oil storage
Stockton, KS	6	Own	Crude oil storage
Kansas City, KS	18,400 (square feet)	Lease	Office space

Rent under our lease for the Kansas City office space is approximately $240,000 annually, plus a portion of operating expenses and taxes, increasing to approximately $268,000 in 2008. The lease expires in 2009. We expect that our current owned and leased facilities will be sufficient for our needs over the next twelve months.

Prior to the consummation of this offering, we will transfer ownership of certain parcels of land, including land that the fertilizer plant is situated on, to the Partnership so that the Partnership will be able to operate the fertilizer plant on its own land. Additionally, we will enter into a new cross easement agreement with the Partnership so that both we and the Partnership will be able to access and utilize each other s land in certain circumstances in order to operate our respective businesses in a manner to provide flexibility for both parties to develop their respective properties, without depriving either party of the benefits associated with the continuous reasonable use of the other parties property. For more information on this cross-easement agreement, see The Nitrogen Fertilizer Limited Partnership Other Intercompany Agreements.

Legal Proceedings

We are, and will continue to be, subject to litigation from time to time in the ordinary course of our business, including matters such as those described above under Environmental Matters. We are not party to any pending legal proceedings that we believe will have a material impact on our business, and there are no existing legal proceedings where we believe that the reasonably possible loss or range of loss is material, other than certain legal proceedings related to the flood and crude oil discharge, which are described under Flood and Crude Oil Discharge.

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FLOOD AND CRUDE OIL DISCHARGE

Overview

During the weekend of June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville. The river crested more than 10 feet above flood stage, setting a new record for the river. Approximately 2,000 citizens and hundreds of homes throughout the city of Coffeyville were affected. Our refinery and the nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded and were forced to conduct emergency shutdowns and evacuate. The majority of the refinery s process units were under four to six feet of water and portions of the refinery s tank farms and wastewater treatment area were covered with eight to 10 feet of water. As a result, the refinery and nitrogen fertilizer facilities sustained major damage and required extensive repairs.

Property Damage and Lost Earnings

The refinery sustained damage to a large number of pumps, motors, tanks, control rooms and other buildings, electrical equipment and electronic controls and required significant clean-up in the areas surrounding the water and wastewater treatment plants. We hired nearly 1,000 extra contract workers to help repair and replace damaged equipment. The refinery started operating its reformer on August 6, 2007 and began to charge crude oil to the facility on August 9, 2007. Substantially all of the refinery s units were in operation by August 20, 2007.

The nitrogen fertilizer facility, situated on slightly higher ground, sustained less damage than the refinery. Bringing the nitrogen fertilizer plant back on line involved replacing or repairing 30% of all electric drives, repairing 60% of the plant s motor control centers, refurbishing 100% of distributive control systems and programmable logic controllers, and repairing the main control room. The nitrogen fertilizer facility initiated startup at its production facility on July 13, 2007.

The total third party cost to repair the refinery is currently estimated at approximately $86 million, and the total third party cost to repair the nitrogen fertilizer facility is currently estimated at approximately $4 million.

Crude Oil Discharge

Because the Verdigris River rose so rapidly during the flood, much faster than predicted, our employees had to shut down and secure the refinery in six to seven hours, rather than the 24 hours typically needed for such an effort. Despite our efforts to secure the refinery prior to its evacuation as a result of the flood, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007. In particular, crude oil and its fractions were released from refinery storage tanks and the refinery sewer system. Crude oil was carried by floodwaters downstream from our refinery and into residential and commercial areas.

In response to the crude oil discharge, on July 1, 2007 we established an incident command center and assembled a team of environmental consultants and oil spill response contractors to manage our response to the crude oil discharge.

The O Brien s Group managed the overall process, including containment and recovery. The O Brien s Group is the largest provider of emergency preparedness and crisis management services to the energy and internal shipping industries.

United States Environmental Services, LLC provided operations support. This firm is a full-service environmental contracting company specializing in environmental emergency response, in-plant industrial services, contaminated site remediation, chemical/biological terrorism response, safety training and industrial hygiene.

The Center for Toxicology and Environmental Health oversaw sampling, analysis and reporting for the operation. This firm specializes in toxicology, risk assessment, industrial hygiene, occupational health and response to emergencies involving the release or threat of release of chemicals.

On July 2, 2007, the U.S. Environmental Protection Agency (EPA) dispatched additional oil spill response contractors to the site with the EPA s Mobile Command Post to monitor and coordinate pollution assessments related to the flooding and the crude oil discharge.

Beginning on or about July 2, 2007, the EPA s oil spill response contractors and we began jointly conducting daily aerial overflights of the Coffeyville area and our refinery. On or about July 2, 2007, (a) crude oil from the refinery was observed to be in the flood waters surrounding the above-ground storage tanks located at our refinery, (b) oil was observed in the Verdigris River and in flood waters that had inundated a portion of the town of Coffeyville, and (c) a sheen of oil was observed in the Verdigris River extending downstream from our refinery approximately ten miles.

Representatives from the Kansas Department of Health and Environment and the Oklahoma Department of Environmental Quality have also been heavily involved in participating in the response to the oil discharge.

EPA Administrative Order on Consent

On July 10, 2007, we entered into an administrative order on consent (the Consent Order) with the EPA. As set forth in the Consent Order, the EPA concluded that the discharge of oil from our refinery caused and may continue to cause an imminent and substantial threat to the public health and welfare. Pursuant to the Consent Order, we agreed to perform specified remedial actions to respond to the discharge of crude oil from our refinery.

Under the Consent Order, within ninety (90) days after the completion of such remedial action, we will submit to the EPA for review and approval a final report summarizing the actions taken to comply with the Consent Order. We have worked with the EPA throughout the recovery process and we could be required to reimburse the EPA s costs under the federal Oil Pollution Act. Except as otherwise set forth in the Consent Order, the Consent Order does not limit the EPA s rights to seek other legal, equitable or administrative relief or action as it deems appropriate and necessary against us or from requiring us to perform additional activities pursuant to applicable law. Among other things, EPA reserved the right to assess administrative penalties against us and/or to seek civil penalties against us. In addition, the Consent Order states that it is not a satisfaction of or discharge from any claim or cause of action against us or any person for any liability we or such person may have under statutes or the common law, including any claims of the United States for penalties, costs and damages.

We are currently remediating the contamination caused by the crude oil discharge and expect our remedial actions to continue until December 2007. We estimate that the total costs of oil remediation through completion will be approximately $7 million to $10 million. Resolution of third party property damage claims is estimated to cost approximately $25 million to $30 million. As a result, the total cost associated with remediation and property damage claims resolution, including the $16 million which we have estimated as the cost of the property repurchase program described below, is estimated to be approximately $32 million to $40 million. This estimate does not include potential fines or penalties which may be imposed by regulatory authorities or costs arising from potential natural resource damages claims (for which we are unable to estimate a range of possible costs at this time) or possible additional damages arising from class action lawsuits related to the flood.

Property Repurchase Program and Claims for Property Damage

On July 19, 2007 we commenced a program to purchase approximately 330 homes and certain other properties in connection with the flood and the crude oil discharge. We offered to purchase the property of approximately 330 residential landowners (with the consent and cooperation of the City of Coffeyville) for 110% of their pre-flood appraised value (to be established by appraisal conducted without consideration of the flood), without release or other waiver of any rights by the landowners, and without deduction for the greater harm unquestionably caused to these properties by the flood itself. As of September 30, 2007, 300 of these approximately 330 residential properties are under contract. We estimate that this program will cost approximately $16 million, excluding certain costs associated with remediation.

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In addition, in early July 2007 we opened a claims center in Coffeyville and established a toll-free number to facilitate the recording and processing of claims for compensation by those who may have incurred property and other damages related to the oil discharge. Staff assisted local residents in filing claims related to the flood and crude oil discharge. We also offered a toll-free number at the claims call center which was answered 24 hours a day. Call center operators collected property owners information and forwarded it to claims adjustors. The claims adjustors contacted property owners to schedule appointments. Operators also directed callers to local, state and federal disaster response agencies for additional assistance. We are presently reviewing and adjusting these claims.

Litigation

As a result of the crude oil discharge, two putative class action lawsuits (one federal and one state) were filed against us and/or our subsidiaries in July 2007. The federal suit, Danny Dunham vs. Coffeyville Resources, LLC, et. al., was filed in the United States District Court for the District of Kansas at Wichita (case number 6:07-cv-01186-JTM-DWB). The state suit, Western Plains Alliance, LLC and Western Plains Operations, LLC v. Coffeyville Resources Refining & Marketing, LLC, was filed in the District Court of Montgomery County, Kansas (case number 07CV99I).

Each suit seeks class certification under applicable law. In the federal suit, the proposed class includes all residents, domiciliaries and property owners of Coffeyville who were affected by the oil which escaped from our refinery during the flood and who have sustained or may suffer any resulting injury or damage or who have sustained a justifiable fear of sustaining any resulting injury or damage in the future. In the state suit, the proposed class consists of all persons and entities who own or have owned real property within the contaminated area, and all businesses and/or other entities located within the contaminated area. To date no class has yet been certified, and any class, if certified, may be broader, narrower, or different than the classes currently proposed. The plaintiffs in the state suit have filed a motion for class certification and this motion is scheduled for hearing on October 24-26, 2007.

The federal suit alleges that the crude oil discharge resulted from our negligent operation of the refinery and that class members suffered damages, including damages to their personal and real property, diminished property value, lost full use and enjoyment of their property, lost or diminished business income and comprehensive remediation costs. The federal suit seeks recovery under the federal Oil Pollution Act, which imposes a duty of compensation and remediation on parties responsible for discharge or release of oil into the navigable waters of the United States, and Kansas statutory law, which imposes a duty of compensation on a party that releases any material detrimental to the soil or waters of Kansas. The suit also asserts claims related to negligence, trespass and nuisance under Kansas common law. The suit seeks unspecified damages. We have filed a motion to dismiss the federal suit for lack of subject matter jurisdiction.

The state suit alleges that the class has suffered damages, including damages to real and personal property, decreases in property values, decreases in business revenues, loss of the right to the full and exclusive use of real property, increased costs for maintenance and upkeep, and costs for monitoring, detection, management and removal of the crude oil. The suit asserts claims against us related to negligence, nuisance and trespass. The complaint also alleges that we have a duty under Kansas statutory law to compensate owners of property affected by the release or discharge of contamination. The suit seeks unspecified damages as well as injunctive relief requiring us to take such steps as are reasonably necessary to prevent the further migration of the crude oil and for the remediation and/or removal of the crude oil. We have filed an answer in the state suit denying any liability for negligence, nuisance and trespass, while acknowledging that plaintiffs property damages and losses resulting from the oil release (but not from the flood) are properly compensable pursuant to Kansas state law if plaintiffs did not contribute to such contamination.

We intend to defend against these suits vigorously. Due to the uncertainty of these suits, we are unable to estimate a range of possible loss at this time. Presently, we do not expect that the resolution of either or both of these suits will have a significant adverse effect on our business and results of operations.

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Insurance

During and after the time of the flood and crude oil discharge, Coffeyville Resources, LLC was insured under insurance policies that were issued by a variety of insurers and which covered various risks, such as damage to our property, interruption of our business, environmental cleanup costs, and potential liability to third parties for bodily injury or property damage. These coverages include the following:

Our primary property damage and business interruption insurance program provides $300 million of coverage for flood-related damage, subject to a deductible of $2.5 million per occurrence and a 45-day waiting period for business interruption loss. While we believe that property insurance should cover substantially all of the estimated total physical damage to our property, our insurance carriers have cited potential coverage limitations and defenses that might preclude such a result.

Our builders risk policy provides coverage for property damage to buildings in the course of construction. Flood-related loss or damage is subject to a $100,000 deductible and sub-limit of $50 million.

Our environmental insurance coverage program provides coverage for bodily injury, property damage, and cleanup costs resulting from new pollution conditions. At the time of the flood, the program included a primary policy with a $25 million aggregate limit of liability. This policy was subject to a $1 million self-insured retention and to a sub-limit of $10 million applicable to cleanup costs. In addition, at the time of the flood we had a $25 million excess policy that was triggered by exhaustion of the primary policy. The excess policy covered bodily injury and property damage resulting from new pollution conditions, but did not cover cleanup costs.

Our umbrella and excess liability coverage program provides $100 million of coverage excess of $5 million and other applicable insurance for third-party claims of property damage and bodily injury arising out of the discharge of pollutants.

Coffeyville Resources, LLC promptly notified its insurers of the flood, the crude oil discharge, and related claims and lawsuits. We are in the process of submitting our claims to, responding to information requests from, and negotiating with the insurers with respect to costs and damages related to the flood and crude oil discharge. Although each insurer has reserved its rights under various policy exclusions and limitations and has cited potential coverage defenses, we are vigorously pursuing our insurance recovery claims. We expect that ultimate recovery will be subject to negotiation and, if negotiation is unsuccessful, litigation.

Our insurance policies also provide coverage for interruption to the business, including lost profits, and reimbursement for other expenses and costs we have incurred relating to the damages and losses suffered. This coverage, however, only applies to losses incurred after a business interruption of 45 days. Because both the refinery and the nitrogen fertilizer plant were restored to operation within this 45-day period, a substantial portion of the lost profits incurred because of the flood cannot be claimed under insurance.

Impact on Our Third Quarter 2007 Performance

The flood and crude oil discharge will have a significant adverse impact on our third quarter 2007 financial results. We expect that we will report reduced revenue due to the closure of our facilities for a portion of the third quarter, as well as significant costs related to the flood as a result of the necessary repairs to our facilities and environmental remediation. Although operating results for the quarter ending September 30, 2007 will be significantly below historical levels due to the flood and crude oil discharge, both our refinery and nitrogen fertilizer facility have returned to operating performances at or exceeding levels achieved prior to the flood. For several days during the final weeks of September 2007, we processed in excess of 119,000 barrels per day of crude oil in our refinery. These levels of daily crude processing constitute the highest levels of daily processing ever achieved at the facility. The fertilizer plant has been back in operation since restarting production on July 13, 2007 and has demonstrated an operating performance at pre-flood levels. As of September 30, 2007, we had $168.1 million of borrowing availability under our credit facilities. See Prospectus Summary Our Business Flood and Crude Oil Discharge.

MANAGEMENT

Executive Officers and Directors

Prior to this offering, our business was operated by Coffeyville Acquisition LLC and its subsidiaries. In connection with the offering, Coffeyville Acquisition LLC formed a wholly owned subsidiary, CVR Energy, Inc., which will own all of Coffeyville Acquisition LLC s subsidiaries and which will conduct our business through its subsidiaries following this offering. The following table sets forth the names, positions and ages (as of June 30, 2007) of each person who has been an executive officer or director of Coffeyville Acquisition LLC and who will be an executive officer or director of CVR Energy upon completion of this offering. We also indicate in the biographies below which executive officers and directors of CVR Energy will also hold similar positions with the managing general partner of the Partnership. Senior management of CVR Energy will manage the Partnership pursuant to a services agreement to be entered into among us, the Partnership and the managing general partner. All of the named executive officers of CVR Energy listed below will devote all of their time to CVR Energy and its subsidiaries, except that certain of them will also devote a portion of their time to the management of the Partnership (see page 200).

Name	Age	Position
John J. Lipinski	56	Chairman of the Board of Directors, Chief Executive Officer and President
Stanley A. Riemann	56	Chief Operating Officer
James T. Rens	41	Chief Financial Officer and Treasurer
Edmund S. Gross	56	Senior Vice President, General Counsel and Secretary
Robert W. Haugen	49	Executive Vice President, Refining Operations
Wyatt E. Jernigan	55	Executive Vice President, Crude Oil Acquisition and Petroleum Marketing
Kevan A. Vick	53	Executive Vice President and Fertilizer General Manager
Christopher G. Swanberg	49	Vice President, Environmental, Health and Safety
Wesley K. Clark	62	Director
Scott L. Lebovitz	32	Director
Regis B. Lippert	67	Director
George E. Matelich	51	Director
Stanley de J. Osborne	36	Director
Kenneth A. Pontarelli	37	Director
Mark E. Tomkins	52	Director

John J. Lipinski has served as our chief executive officer and president and a member of our board of directors since September 2006 and as chief executive officer and president of Coffeyville Acquisition LLC since June 24, 2005. Mr. Lipinski also served as a director of Coffeyville Acquisition LLC from June 24, 2005 until immediately prior to this offering. Mr. Lipinski will also become chairman of our board of directors, the chief executive officer and a director of the managing general partner of the Partnership and the chief executive officer and president of Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC prior to the consummation of this offering. Mr. Lipinski has over 35 years of experience in the petroleum refining and nitrogen fertilizer industries. He began his career with Texaco Inc. In 1985, Mr. Lipinski joined The Coastal Corporation eventually serving as Vice President of Refining with overall responsibility for Coastal Corporation s refining and petrochemical operations. Upon the merger of Coastal with El Paso Corporation in 2001, Mr. Lipinski was promoted to Executive Vice President of Refining and Chemicals, where he was responsible for all refining, petrochemical, nitrogen based chemical processing, and lubricant operations, as well as the corporate engineering and construction group. Mr. Lipinski left El Paso in 2002 and became an independent management

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consultant. In 2004, he became a Managing Director and Partner of Prudentia Energy, an advisory and management firm. Mr. Lipinski graduated from Stevens Institute of Technology with a Bachelor of Engineering (Chemical) and received a Juris Doctor degree from Rutgers University School of Law.

Stanley A. Riemann has served as chief operating officer of our company since September 2006, chief operating officer of Coffeyville Acquisition LLC since June 24, 2005 and chief operating officer of Coffeyville Resources, LLC since February 27, 2004. Mr. Riemann will also become the chief operating officer of the managing general partner of the Partnership, Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC prior to the consummation of this offering. Prior to joining our company in March 2004, Mr. Riemann held various positions associated with the Crop Production and Petroleum Energy Division of Farmland Industries, Inc. over 29 years, including, most recently, Executive Vice President of Farmland Industries and President of Farmland s Energy and Crop Nutrient Division. In this capacity, he was directly responsible for managing the petroleum refining operation and all domestic fertilizer operations, which included the Trinidad and Tobago nitrogen fertilizer operations. His leadership also extended to managing Farmland s interests in SF Phosphates in Rock Springs, Wyoming and Farmland Hydro, L.P., a phosphate production operation in Florida, and managing all company-wide transportation assets and services. On May 31, 2002, Farmland Industries, Inc. filed for Chapter 11 bankruptcy protection. Mr. Riemann served as a board member and board chairman on several industry organizations including Phosphate Potash Institute, Florida Phosphate Council, and International Fertilizer Association. He currently serves on the Board of The Fertilizer Institute. Mr. Riemann received a bachelor of science from the University of Nebraska and an MBA from Rockhurst University.

James T. Rens has served as chief financial officer and treasurer of our company since September 2006, chief financial officer and treasurer of Coffeyville Acquisition LLC since June 24, 2005 and chief financial officer and treasurer of Coffeyville Resources, LLC since February 27, 2004. Mr. Rens will also become the chief financial officer and treasurer of the managing general partner of the Partnership, Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC prior to the consummation of this offering. Before joining our company, Mr. Rens was a consultant to the Original Predecessor s majority shareholder from November 2003 to March 2004, assistant controller at Koch Nitrogen Company from June 2003, which was when Koch acquired the majority of Farmland s nitrogen fertilizer business, to November 2003 and Director of Finance of Farmland s Crop Production and Petroleum Divisions from January 2002 to June 2003. From May 1999 to January 2002, Mr. Rens was Controller and chief financial officer of Farmland Hydro L.P. Mr. Rens has spent over 18 years in various accounting and financial positions associated with the fertilizer and energy industry. Mr. Rens received a Bachelor of Science degree in accounting from Central Missouri State University.

Edmund S. Gross has served as vice president, general counsel, and secretary of our company since September 2006, secretary of Coffeyville Acquisition LLC since June 24, 2005 and general counsel and secretary of Coffeyville Resources, LLC since July 15, 2004. Mr. Gross will also become the senior vice president of our company and the senior vice president, general counsel, and secretary of the managing general partner of the Partnership, Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC prior to the consummation of this offering. Prior to joining Coffeyville Resources, Mr. Gross was Of Counsel at Stinson Morrison Hecker LLP in Kansas City, Missouri from 2002 to 2004, was Senior Corporate Counsel with Farmland Industries, Inc. from 1987 to 2002 and was an associate and later a partner at Weeks,Thomas & Lysaught, a law firm in Kansas City, Kansas, from 1980 to 1987. Mr. Gross received a Bachelor of Arts degree in history from Tulane University, a Juris Doctor from the University of Kansas and an MBA from the University of Kansas.

Robert W. Haugen joined our business on June 24, 2005 and has served as executive vice president, refining operations at our company since September 2006 and as executive vice president engineering & construction at Coffeyville Resources, LLC since June 24, 2005. Mr. Haugen will also become executive vice president, refining operations at Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC prior to the consummation of this offering. Mr. Haugen brings 25 years of experience in the refining, petrochemical and nitrogen fertilizer business to our company. Prior to joining us, Mr. Haugen was a Managing Director and Partner of Prudentia Energy, an advisory and management firm focused on mid-stream/downstream energy sectors, from January 2004 to June

2005. On leave from Prudentia, he served as the Senior Oil Consultant to the Iraqi Reconstruction Management Office for the U.S. Department of State. Prior to joining Prudentia Energy, Mr. Haugen served in numerous engineering, operations, marketing and management positions at the Howell Corporation and at the Coastal Corporation. Upon the merger of Coastal and El Paso in 2001, Mr. Haugen was named Vice President and General Manager for the Coastal Corpus Christi Refinery, and later held the positions of Vice President of Chemicals and Vice President of Engineering and Construction. Mr. Haugen received a B.S. in Chemical Engineering from the University of Texas.

Wyatt E. Jernigan has served as executive vice president, crude oil acquisition and petroleum marketing at our company since September 2006 and as executive vice president crude & feedstocks at Coffeyville Resources, LLC since June 24, 2005. Mr. Jernigan will also become executive vice president, crude oil acquisition and petroleum marketing at Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC prior to the consummation of this offering. Mr. Jernigan has 30 years of experience in the areas of crude oil and petroleum products related to trading, marketing, logistics and business development. Most recently, Mr. Jernigan was Managing Director with Prudentia Energy, an advisory and management firm focused on mid-stream/downstream energy sectors, from January 2004 to June 2005. Most of his career was spent with Coastal Corporation and El Paso, where he held several positions in crude oil supply, petroleum marketing and asset development, both domestic and international. Following the merger between Coastal Corporation and El Paso in 2001, Mr. Jernigan assumed the role of Managing Director for Petroleum Markets Originations. Mr. Jernigan attended Virginia Wesleyan College, majoring in Sociology, and has training in petroleum fundamentals from the University of Texas.

Kevan A. Vick has served as executive vice president and fertilizer general manager at our company since September 2006 and senior vice president at Coffeyville Resources Nitrogen Fertilizers, LLC since February 27, 2004. Mr. Vick will also become executive vice president and fertilizer general manager of the managing general partner of the Partnership and Coffeyville Acquisition III LLC prior to the consummation of this offering. He has served on the board of directors of Farmland MissChem Limited in Trinidad and SF Phosphates. He has nearly 30 years of experience in the Farmland organization and is one of the most highly respected executives in the nitrogen fertilizer industry, known for both his technical expertise and his in-depth knowledge of the commercial marketplace. Prior to joining Coffeyville Resources LLC, he was general manager of nitrogen manufacturing at Farmland from January 2001 to February 2004. Mr. Vick received a bachelor of science in chemical engineering from the University of Kansas and is a licensed professional engineer in Kansas, Oklahoma, and Iowa.

Christopher G. Swanberg has served as vice president, environmental, health and safety at our company since September 2006 and as vice president, environmental, health and safety at Coffeyville Resources, LLC since June 24, 2005. Mr. Swanberg will also become vice president, environmental, health and safety at Coffeyville Acquisition LLC, Coffeyville Acquisition II LLC, and Coffeyville Acquisition III LLC prior to the consummation of this offering. He has served in numerous management positions in the petroleum refining industry such as Manager, Environmental Affairs for the refining and marketing division of Atlantic Richfield Company (ARCO), and Manager, Regulatory and Legislative Affairs for Lyondell-Citgo Refining. Mr. Swanberg s experience includes technical and management assignments in project, facility and corporate staff positions in all environmental, safety and health areas. Prior to joining Coffeyville Resources, he was Vice President of Sage Environmental Consulting, an environmental consulting firm focused on petroleum refining and petrochemicals, from September 2002 to June 2005 and Senior HSE Advisor of Pilko & Associates, LP from September 2000 to September 2002. Mr. Swanberg received a B.S. in Environmental Engineering Technology from Western Kentucky University and an MBA from the University of Tulsa.

Wesley K. Clark has been a member of our board of directors since September 2006. He also was a member of the board of directors of Coffeyville Acquisition LLC from September 20, 2005 until immediately prior to this offering. Since March 2003 he has been the Chairman and Chief Executive Officer of Wesley K. Clark & Associates, a business services and development firm based in Little Rock, Arkansas. Mr. Clark also serves as senior advisor to GS Capital Partners V Fund, L.P. From

March 2001 to February 2003 he was a Managing Director of the Stephens Group Inc. From July 2000 to March 2001 he was a consultant for Stephens Group Inc. Prior to that time, Mr. Clark served as the Supreme Allied Commander of NATO and Commander-in-Chief for the United States European Command and as the Director of the Pentagon s Strategic Plans and Policy operation. Mr. Clark retired from the United States Army as a four-star general in July 2000 after 38 years in the military and received many decorations and honors during his military career. Mr. Clark is a graduate of the United States Military Academy and studied as a Rhodes Scholar at the Magdalen College at the University of Oxford. Mr. Clark is a director of Argyle Security Acquisition Corp.

Scott L. Lebovitz has been a member of our board of directors since September 2006. He also was a member of the board of directors of Coffeyville Acquisition LLC from June 24, 2005 until immediately prior to this offering. Mr. Lebovitz will also become a director of the managing general partner of the Partnership and of Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC prior to the consummation of this offering. Mr. Lebovitz is a Vice President in the Merchant Banking Division of Goldman, Sachs & Co. Mr. Lebovitz joined Goldman Sachs in 1997. He is a director of Village Voice Media Holdings, LLC and Energy Future Holdings Corp. He received his B.S. in Commerce from the University of Virginia.

Regis B. Lippert has been a member of our board of directors since June 2007. He was also a member of the board of directors of Coffeyville Acquisition LLC from June 2007 until immediately prior to this offering. He is the founder, principal shareholder and a director of INTERCAT, Inc., a specialty chemicals company which primarily develops, manufactures, markets and sells specialty catalysts used in petroleum refining. Mr. Lippert serves as President and Chief Executive Officer of INTERCAT, Inc. and its affiliate companies and is a Managing Director of INTERCAT Europe B.V. Mr. Lippert is also a director of Indo Cat Private Limited, an Indian company which is part of a joint venture between INTERCAT, Inc. and Indian Oil Corporation Limited. Prior to founding INTERCAT, Mr. Lippert served from 1981 to 1985 as President, Chief Executive Officer and a director of Katalistiks, Inc., a manufacturer of fluid cracking catalysts which ultimately became a subsidiary of Union Carbide Corporation. From 1979 to 1981, Mr. Lippert was an Executive Vice President with Catalysts Recovery, Inc. In this capacity he was responsible for developing the joint venture which ultimately formed Katalistiks. From 1963 to 1979, Mr. Lippert was employed by Engelhard Minerals and Chemical Co., where he attained the position of Director of Sales and Marketing/Catalysts. Mr. Lippert attended Carnegie-Mellon University where he studied metallurgy. He is a member of the National Petroleum Refiners Association.

George E. Matelich has been a member of our board of directors since September 2006 and a member of the board of directors of Coffeyville Acquisition LLC since June 24, 2005. Mr. Matelich will also become a director of the managing general partner of the Partnership and of Coffeyville Acquisition III LLC prior to the consummation of this offering. Mr. Matelich has been a Managing Director of Kelso & Company since 1990. Mr. Matelich has been affiliated with Kelso since 1985. Mr. Matelich is a Certified Public Accountant and holds a Certificate in Management Consulting. Mr. Matelich received a B.A. in Business Administration from the University of Puget Sound and an M.B.A. from the Stanford Graduate School of Business. He is a director of Global Geophysical Services, Inc. and Waste Services, Inc. He is also a Trustee of the University of Puget Sound and serves on the National Council of the American Prairie Foundation.

Stanley de J. Osborne has been a member of our board of directors since September 2006 and a member of the board of directors of Coffeyville Acquisition LLC since June 24, 2005. Mr. Osborne will also become a director of the managing general partner of the Partnership and of Coffeyville Acquisition III LLC prior to the consummation of this offering. Mr. Osborne has been a Vice President of Kelso & Company since 2004. Mr. Osborne has been affiliated with Kelso since 1998. Prior to joining Kelso, Mr. Osborne was an Associate at Summit Partners. Previously, Mr. Osborne was an Associate in the Private Equity Group and an Analyst in the Financial Institutions Group at J.P. Morgan & Co. He received a B.A. in Government from Dartmouth College. Mr. Osborne is a director of Custom Building Products, Inc., Global Geophysical Services, Inc. and Traxys S.A.

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Kenneth A. Pontarelli has been a member of our board of directors since September 2006. He also was a member of the board of directors of Coffeyville Acquisition LLC from June 24, 2005 until immediately prior to this offering. Mr. Pontarelli will also become a director of the managing general partner of the Partnership and of Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC prior to the consummation of this offering. Mr. Pontarelli is a managing director in the Merchant Banking Division of Goldman, Sachs & Co. Mr. Pontarelli joined Goldman, Sachs & Co. in 1992 and became a managing director in 2004. He is a director of Cobalt International Energy, L.P., NextMedia Investors, LLC, Knight Inc. and Energy Future Holdings Corp. He received a B.A. from Syracuse University and an M.B.A. from Harvard Business School.

Mark E. Tomkins has been a member of our board of directors since January 2007. He also was a member of the board of directors of Coffeyville Acquisition LLC from January 2007 until immediately prior to this offering. Mr. Tomkins has served as the senior financial officer at several large companies during the past ten years. He was Senior Vice President and Chief Financial Officer of Innovene, a petroleum refining and chemical polymers business and a subsidiary of British Petroleum, from May 2005 to January 2006, when Innovene was sold to a strategic buyer. From January 2001 to May 2005 he was Senior Vice President and Chief Financial Officer of Vulcan Materials Company, a construction materials and chemicals company, with responsibility for finance, treasury, tax, internal audit, investor relations, strategic planning and information technology. From August 1998 to January 2001 Mr. Tomkins was Senior Vice President and Chief Financial Officer of Chemtura (formerly GreatLakes Chemical Corporation), a specialty chemicals company. From July 1996 to August 1998 he worked at Honeywell Corporation as Vice President of Finance and Business Development for its polymers division and as Vice President of Finance and Business Development for its electronic materials division. From November 1990 to July 1996 Mr. Tomkins worked at Monsanto Company in various financial and accounting positions, including Chief Financial Officer of the growth enterprises division from January 1995 to July 1996. Prior to joining Monsanto he worked at Cobra Corporation and as an auditor in private practice. Mr. Tomkins received a B.S. degree in business, with majors in Finance and Management, from Eastern Illinois University and an MBA from Eastern Illinois University.

Board of Directors

Our board of directors consists of eight members. The current directors are included above. Our directors are elected annually to serve until the next annual meeting of stockholders or until their successors are duly elected and qualified.

Prior to the completion of this offering, our board will have an audit committee, a compensation committee, a nominating and corporate governance committee and a conflicts committee. Our board of directors has determined that we are a controlled company under the rules of the New York Stock Exchange, and, as a result, will qualify for, and may rely on, exemptions from certain corporate governance requirements of the New York Stock Exchange. Pursuant to the controlled company exception to the board of directors and committee composition requirements, we will be exempt from the rules that require that (a) our board of directors be comprised of a majority of independent directors, (b) our compensation committee be comprised solely of independent directors and (c) our nominating and corporate governance committee be comprised solely of independent directors as defined under the rules of the New York Stock Exchange. The controlled company exception does not modify the independence requirements for the audit committee, and we intend to comply with the audit committee requirements of the Sarbanes-Oxley Act and the New York Stock Exchange rules, which require that our audit committee be composed of at least one independent director at the closing of this offering, a majority of independent directors within 90 days of this offering and all independent directors within a year of this offering.

Audit Committee. Our audit committee will be comprised of Messrs. Mark Tomkins, Wesley Clark, and Stanley de J. Osborne. Mr. Tomkins will be chairman of the audit committee. Our board of

directors has determined that Mr. Tomkins qualifies as an audit committee financial expert. The audit committee s responsibilities will be to review the accounting and auditing principles and procedures of our company with a view to providing for the safeguard of our assets and the reliability of our financial records by assisting the board of directors in monitoring our financial reporting process, accounting functions and internal controls; to oversee the qualifications, independence, appointment, retention, compensation and performance of our independent registered public accounting firm; to recommend to the board of directors the engagement of our independent accountants; to review with the independent accountants the plans and results of the auditing engagement; and to oversee whistle-blowing procedures and certain other compliance matters.

Compensation Committee. Our compensation committee will be comprised of Messrs. George E. Matelich, Kenneth Pontarelli, Wesley Clark, and Mark Tomkins. Mr. George E. Matelich will be the chairman of the compensation committee. The principal responsibilities of the compensation committee will be to establish policies and periodically determine matters involving executive compensation, recommend changes in employee benefit programs, grant or recommend the grant of stock options and stock awards and provide counsel regarding key personnel selection. A subcommittee of the compensation committee consisting of Messrs. Clark and Tomkins will make stock and option awards to the extent deemed necessary or advisable for regulatory purposes. See Executive Compensation Compensation Discussion and Analysis.

Nominating and Corporate Governance Committee. Our nominating and corporate governance committee will be comprised of Messrs. Scott L. Lebovitz, Stanley de J. Osborne, John J. Lipinski and Regis B. Lippert. Mr. Scott L. Lebovitz will be the chairman of the nominating and corporate governance committee. The principal duties of the nominating and corporate governance committee will be to recommend to the board of directors proposed nominees for election to the board of directors by the stockholders at annual meetings and to develop and make recommendations to the board of directors regarding corporate governance matters and practices.

Conflicts Committee. Our conflicts committee initially will be comprised of Mr. Mark Tomkins. The principal duties of the conflicts committee will be to determine, in accordance with the conflicts of interests policy adopted by our board of directors, if the resolution of a conflict of interest between CVR Energy and our subsidiaries, on the one hand, and the Partnership, the Partnership s managing general partner or any subsidiary of the Partnership, on the other hand, is fair and reasonable to us.

Executive Compensation

Compensation Discussion and Analysis

Overview

To date, the compensation committee of the board of directors of Successor has overseen companywide compensation practices and specifically reviewed, developed and administered executive compensation programs, and made recommendations to the board of directors of Successor on compensation matters. Messrs. George E. Matelich, Kenneth Pontarelli and John J. Lipinski served as members of this committee during 2006 and prior to this offering. Prior to the completion of this offering, our board of directors will establish a compensation committee comprised of Messrs. George E. Matelich (as chairperson), Kenneth Pontarelli, Wesley Clark and Mark Tomkins, which will (except where otherwise noted) generally take over the duties of the compensation committee of the board of directors of Successor. For purposes of the Compensation Discussion and Analysis, the board of directors and the compensation committee refer to the board of directors of the Successor and the compensation committee thereof. We do not expect our overall compensation philosophy to materially change as a result of the establishment of the new compensation committee. The definitions of certain defined terms used in this Compensation Discussion and Analysis (and in other parts of the Executive Compensation section), including bonus plan, bonus points, Phantom Unit Plan I, Phantom Unit

Plan II, phantom points, phantom service points, phantom performance points,

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common units, profits interests, override units, operating units and value units, among others, are contained in the section of this prospectus entitled Glossary of Selected Terms.

The executive compensation philosophy of the compensation committee is threefold:

To align the executive officers interest with that of the stockholders and stakeholders, which provides long-term economic benefits to the stockholders;

To provide competitive financial incentives in the form of salary, bonuses, and benefits with the goal of retaining and attracting talented and highly motivated executive officers; and

To maintain a compensation program whereby the executive officers, through exceptional performance and equity ownership, will have the opportunity to realize economic rewards commensurate with appropriate gains of other equity holders and stake holders.

The compensation committee reviews and makes recommendations to the board of directors regarding our overall compensation strategy and policies, with the full board of directors having the final authority on compensation matters. The board of directors may from time to time delegate to the compensation committee the authority to take actions on specific compensation matters or with respect to compensation matters for certain employees or officers. In the past, there has been no such delegation, but following the completion of this offering, our board of directors may delegate to the compensation committee, for example, in order to comply with Section 16 of the Exchange Act or Section 162(m) of the Internal Revenue Code of 1986 when those laws require actions by outside or non-employee directors, as applicable. Rule 16b-3 issued under Section 16 of the Exchange Act provides that transactions between an issuer and its officers or directors involving issuer securities may be exempt from Section 16(b) of the Exchange Act if it meets certain requirements, one of which is approval by a committee of the board of directors of the issuer consisting of two or more non-employee directors. Section 162(m) of the Code limits deductions by publicly held corporations for compensation paid to its covered employees (i.e., its chief executive officer and next four highest compensated officers) to the extent that the employee s compensation for the taxable year exceeds $1,000,000. This limit does not apply to qualified performance-based compensation, which requires, among other things, satisfaction of a performance goal that is established by a committee of the board of directors consisting of two or more outside directors.

The compensation committee (1) develops, approves and oversees policies relating to compensation of our chief executive officer and other executive officers, (2) discharges the board s responsibility relating to the establishment, amendment, modification, or termination of the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) (the Phantom Unit Plan I) (and will discharge similar responsibilities relating to the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) (the Phantom Unit Plan II), which we intend to adopt prior to the completion of this offering), health and welfare plans, incentive plans, defined contribution plans (401(k) plans), and any other benefit plan, program or arrangement which we sponsor or maintain and (3) discharges the responsibilities of the override unit committee of the board of directors. Following the completion of this offering, the newly formed compensation committee of CVR Energy will take actions in accordance with its charter and applicable law.

Specifically, the compensation committee reviews and makes recommendations to the board of directors regarding annual and long-term performance goals and objectives for the chief executive officer and our other senior executives; reviews and makes recommendations to the board of directors regarding the annual salary, bonus and other incentives and benefits, direct and indirect, of the chief executive officer and our senior executives; reviews and authorizes the company to enter into employment, severance or other compensation agreements with the chief executive officer and other senior executives; administers the executive incentive plan, including the Phantom Unit Plan I (and the Phantom Unit Plan II, when adopted); establishes and periodically reviews perquisites and fringe benefits policies; reviews annually the implementation of our company-wide incentive bonus program known as the Variable Compensation Plan (which is referred to as the Income Sharing Plan beginning

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in 2007) and contributions to our 401(k) plan; and performs such duties and responsibilities as may be assigned by the board of directors to the compensation committee under the terms of any executive compensation plan, incentive compensation plan or equity-based plan and as may be assigned to the compensation committee with respect to the issuance and management of the override units in Coffeyville Acquisition LLC and, after the consummation of the transactions, Coffeyville Acquisition II LLC.

The compensation committee has regularly scheduled meetings concurrent with the board of directors meetings and additionally meets at other times as needed throughout the year. Frequently issues are discussed via teleconferencing. The chief executive officer, while a member of the compensation committee prior to this offering, did not participate in the determination of his own compensation, thereby avoiding any potential conflict of interest. However, he actively provided and will continue to provide guidance and recommendations to the committee regarding the amount and form of the compensation of the other executive officers and key employees. During 2006 and prior to this offering, given that the compensation committee consisted of senior representatives of the Goldman Sachs Funds and the Kelso Funds, as well as our chief executive officer, the board did not change or reject decisions made by the compensation committee.

Compensation paid to executive officers is closely aligned with our performance on both a short-term and long-term basis. Compensation is structured competitively in order to attract, motivate and retain executive officers and key employees and is considered crucial to our long-term success and the long-term enhancement of stockholder value. Compensation is structured to ensure that the executive officers objectives and rewards are directly correlated to our long-term objectives and the executive officers interests are aligned with those of stockholders. To this end, the compensation committee believes that the most critical component of compensation is equity compensation.

The following discusses in detail the foundation underlying and the drivers of our executive compensation philosophy, and also how the related decisions are made. Qualitative information related to the most important factors utilized in the analysis of these decisions is described.

Elements of Compensation

The three primary components of the compensation program are salary, an annual cash incentive bonus, and equity awards. Executive officers are also provided with benefits that are generally available to our salaried employees.

While these three components are related, we view them as separate and analyze them as such. The compensation committee believes that equity compensation is the primary motivator in attracting and retaining executive officers. Salary and cash incentive bonuses are viewed as secondary; however, the compensation committee views a competitive level of salary and cash bonus as critical to retaining talented individuals.

Base Salary

We fix the base salary of each of our executive officers at a level we believe enables us to hire, motivate, and retain individuals in a competitive environment and to reward satisfactory individual and company performance. In determining its recommendations for salary levels, the compensation committee takes into account peer group pay and individual performance.

With respect to our peer group, management, through the chief executive officer, provides the compensation committee with information gathered through a detailed annual review of executive compensation programs of other publicly and privately held companies in our industry, which are similar to us in size and operations (among other factors). In 2006, management reviewed and provided information to the compensation committee regarding the salary, bonus and other compensation amounts paid to named executive officers in respect of 2005 for the following independent refining companies, which we view as members of our peer group: Frontier Oil

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Corporation, Giant Industries, Inc., Holly Corporation, Western Refining Company and Tesoro Corporation. It then averaged these peer group salary levels over a number of years to develop a range of salaries of similarly situated executives of these companies, and used this range as a factor in determining base salary (and overall cash compensation) of the named executive officers. Management also reviewed the differences in levels of compensation among the named executive officers of this peer group, and used these differences as a factor in setting a different level of salary and overall compensation for each of our named executive officers based on their relative positions and levels of responsibility.

With respect to individual performance, the compensation committee considered, among other things, the following specific achievements over the past 18 months with respect to Messrs. Riemann, Rens, Haugen and Jernigan. Please see the section in this Compensation Discussion and Analysis entitled Equity for a detailed discussion of our chief executive officer s specific achievements.

Stan A. Riemann, our Chief Operating Officer, was responsible for the following key developments during 2006: (1) successful coordination of capital and expansion projects between our refining business and our nitrogen fertilizer business; (2) oversight of our improved crude oil gathering, storage and purchasing system which resulted in enhanced margins in our refining business; (3) revisions to our fertilizer sales effort, resulting in higher netbacks (unit price of fertilizer offered on a delivered basis, excluding shipping costs); and (4) realignment of the operating responsibilities of our senior management and other key employees in order to improve our day to day operations and facility safety.

James T. Rens, our Chief Financial Officer and Treasurer, was responsible for the following major achievements: (1) increasing the reliability and security of our computer information systems, including through the identification and hiring of a new chief information officer; (2) coordinating among management, underwriters, equity holders, auditors and counsel in connection with our initial public offering; (3) identification and hiring of a chief accounting officer in connection with our preparation for the initial public offering; and (4) supervising and managing the recapitalization of our credit facilities in 2006 which resulted in a $250 million dividend being paid in December 2006.

Robert Haugen, our Executive Vice President, Refining Operations, was given increased responsibilities during 2006. His position grew to include oversight of our overall refinery operations and our engineering and construction operations. Mr. Haugen was responsible for the increased crude throughput of our refinery operations which resulted from better balancing production across the individual units throughout our facility. In addition, Mr. Haugen developed and supervised the detailed processes involved in our plant expansion.

Wyatt Jernigan, our Executive Vice President for Crude Oil Acquisition & Petroleum Marketing, was responsible for the increased volume, efficiency and profitability of our crude gathering system. In particular, Mr. Jernigan (1) was instrumental in expanding our crude oil slate (the types of crudes we purchase) from just a few to approximately a dozen, contributing to the increased profitability of our refined fuel sales; (2) worked to improve our crude purchase cost discount to West Texas Intermediate crude (the industry benchmark); (3) expanded the areas in the United States where our crude oil gathering system operates; (4) helped to increase our rack marketing opportunities (sales into tanker trucks rather than through pipelines); (5) focused on increasing the types of crude oil available to us so that we could fine tune our crude oil slate as pricing and economics shifted in the market; and (6) incorporated price risk management into the operation of our crude gathering system.

Each of the named executive officers has an employment agreement which sets forth his base salary. Salaries are reviewed annually by the compensation committee with periodic informal reviews throughout the year. Adjustments, if any, are usually made on January 1st of the year immediately following the review. The compensation committee most recently reviewed the level of cash salary and bonus for each of the executive officers in November 2006 and noted certain changes of

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responsibilities and promotions. Individual performance, the practices of our peer group of companies and changes in an executive officer s status were considered, and each measurement was given relatively equal weight. The committee determined that no material changes needed to be made at that time to the base salary levels of our executive officers unless they either had a promotion or a significant change of duties. The compensation committee accordingly recommended that the board of directors adjust the salary of Mr. Haugen as Mr. Haugen s overall responsibilities increased (although his title did not formally change) in 2006. Mr. Haugen took over all refinery operations and continued to maintain his other responsibilities including executive management of engineering and construction during 2006. Mr. Haugen s base salary beginning in 2007 was adjusted to $275,000.

Annual Bonus

We use information about total cash compensation paid by members of our peer group of companies, the composition of which is discussed above, in determining both the level of bonus award and the ratio of salary to bonus because we believe that maintaining a level of bonus and a ratio of fixed salary (which is fixed and guaranteed) to bonus (which may fluctuate) that is in line with those of our competitors is an important factor in retaining the executives. The compensation committee also desires that a significant portion of our executive officers compensation package be at risk. That is, a portion of the executive officers overall compensation would not be guaranteed and would be determined based on individual and company performance. With respect to individual performance, the compensation committee considered the specific achievements of our named executive officers, as described above (Messrs. Riemann, Rens, Haugen and Jernigan) and below (Mr. Lipinski).

Our program provides for greater potential bonus awards as the authority and responsibility of a position increase. The chief executive officer has the greatest percentage of his compensation at risk in the form of a discretionary bonus. For example, during 2006, bonuses accounted for over 73% of total salary and bonus for the chief executive officer. Based on our review of the ratios of salary to bonus for the top paid officers in our peer group of companies (listed above) for 2005, we determined that this 73% ratio was in line with our competitors (the 2005 average of this group was approximately 66%). Following the chief executive officer, the other named executive officers have smaller potential bonus payments but retain a significant percentage of their compensation package at risk in the form of potential discretionary bonuses.

Bonuses may be paid in an amount equal to the target percentage, less than the target percentage or greater than the target percentage based on current year performance as recommended by the compensation committee. The performance determination takes into account overall operational performance, financial performance, factors affecting the business and the individual s personal performance. The determination of whether the target bonus amount should be paid is not based on specific metrics, but rather a general assessment of how the business performed as compared to the business plan developed for the year. Due to the nature of the business, financial performance alone may not dictate or be a fair indicator of the performance of the executive officers. Conversely, financial performance may exceed all expectations, but it could be due to outside forces in the industry rather than true performance by an executive that exceeds expectations. In order to take this mismatch into consideration and to assess the executive officers performance on their own merits, the compensation committee makes an assessment of the executive officer s performance separate from the actual financial performance of the company, although such measurement is not based on any specific metrics.

The compensation committee reviewed the individualized performance and company performance as compared to expectations for the year ended December 31, 2006. Because the company s strong performance in 2006 far exceeded the company s internal projections for 2006, the compensation committee decided that the cash incentive bonuses earned by the executive officers for the year ended December 31, 2006 should equal their full target percentages, and such bonuses were paid out during the first week of February 2007. Many company-wide initiatives, such as better utilization of our crude gathering system, improvements in crude purchasing and added emphasis on safety enhancements,

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and certain other efficiency specific achievements of the named executive officers (detailed above and below in the Compensation Discussion and Analysis), drove the value of the business significantly. When our business was acquired in 2005, it was recognized at the outset that salary and target bonus were set low, and the intent was that separate discretionary bonuses would be awarded upon review of accomplishments. The compensation committee provided these additional bonuses in December 2006 to the named executive officers separate and apart from the bonus percentages set forth in the named executive officers employment agreements. It was the decision of the compensation committee that bonuses would be paid to partially bridge the difference between the cash compensation paid to the executive officers in the form of salary and the target bonus percentages originally set forth in their employment agreements, on the one hand, and the average total cash compensation paid by members of our peer group of companies, on the other. The additional December 2006 bonuses were paid in the following amounts: $1,331,790 for Mr. Lipinski; $650,000 for Mr. Riemann; $205,000 for each of Mr. Rens and Mr. Haugen; and $140,000 for Mr. Jernigan.

Annual cash incentive bonuses for our named executive officers are established as part of their respective individual employment agreements. Each of these employment agreements provides that the executive will receive an annual cash performance bonus determined in the discretion of the board of directors, with a target bonus amount specified as a percentage of salary for that executive officer based on individualized performance goals and company performance goals. In connection with the review of peer company compensation practices with respect to total cash compensation paid as described above, in November 2006, the compensation committee determined that the future target percentage for the performance-based annual cash bonus for executive officers should be increased due to their review of these comparable companies. Because we believe that these increased target percentages will give the named executive officers the opportunity to receive total cash compensation more in line with that of our peer group, it is not expected that the additional discretionary bonuses that were awarded in December 2006 will generally be necessary to award to the named executive officers in the future although we may on occasion pay special bonuses for extraordinary efforts. Another benefit of providing the named executive officers with potential total cash compensation in line with that of our peer group through salary and the higher incentive bonus percentages (rather than through salary, target incentive bonus percentages as originally established and the additional discretionary bonus), is that, as a public company, we will be able to create more transparency in our bonus system through a target percentage bonus with actual bonus based on results than through a discretionary bonus. The original structure of target incentive bonus percentages with separate discretionary bonuses was created when our business was acquired in 2005 by private equity investors when we were a private company. The lower salary and target bonus opportunity with the additional discretionary bonus was a carry-over from when our business was part of Farmland, and was also based on private equity market practices of the time. We believe the new structure is more appropriate for a public company.

Beginning in 2007, the named executive officers will no longer participate in our company-wide Variable Compensation Plan (renamed the Income Sharing Plan in 2007). The compensation committee believes their targeted percentages for bonuses beginning in 2007 are adequate and will be monitored and maintained through their employment agreements; therefore, they are no longer eligible to participate in the company-wide bonus plan (Income Sharing Plan).

Equity

We use equity incentives to reward long-term performance. The issuance of equity to executive officers is intended to generate significant future value for each executive officer if the company s performance is outstanding and the value of the company s equity increases for all stockholders. The compensation committee believes that this also promotes long-term retention of the executive. The equity incentives were negotiated to a large degree at the time of the acquisition of our business in June 2005 in order to bring the executive officers compensation package in line with executives at private equity portfolio companies, based on the private equity market practices of the time.

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The greatest share of total compensation to the chief executive officer and other named executive officers (as well as selected senior executives and key employees) is in the form of equity: common units in Coffeyville Acquisition LLC, stock of the underlying subsidiaries, override units within Coffeyville Acquisition LLC or phantom points at Coffeyville Resources, LLC. The total number of such awards is detailed in this registration statement and was approved by the board of directors. All currently available override units and phantom points under the existing plans have been awarded.

The Coffeyville Acquisition LLC Limited Liability Company Agreement provides the methodology for payouts for most of this equity based compensation. In general terms, the agreement provides for two classes of interests in Coffeyville Acquisition LLC: (1) common units and (2) profits interests, which are called override units (and consist of either operating units or value units). Each of the named executive officers has a capital account under which his balance is increased or decreased, as applicable, to reflect his allocable share of net income and gross income of Coffeyville Acquisition LLC, the capital that the named executive officer contributed in exchange for his common units, distributions paid to such named executive officer and his allocable share of net loss and items of gross deduction. Coffeyville Acquisition LLC may make distributions to its members to the extent that the cash available to it is in excess of the business s reasonably anticipated needs. Distributions are generally made to members capital accounts in proportion to the number of units each member holds. The First Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition II LLC, which will govern Coffeyville Acquisition II LLC following the consummation of the Transactions, will have similar provisions to those described above.

The Phantom Unit Plan I works in correlation with the methodology established by the Coffeyville Acquisition LLC Limited Liability Company Agreement for payouts. When adopted, the Phantom Unit Plan II will work in correlation with the methodology established by the Coffeyville Acquisition II Limited Liability Company Agreement for payouts, and the rights and obligations under the Phantom Unit Plan II will be parallel to those of the Phantom Unit Plan I. Each named executive officer contributed personal capital to Coffeyville Acquisition LLC and owns a number of units proportionate to his contribution.

All issuances of override units and phantom points made through December 31, 2006 were made at what the board of directors determined to be their fair value on their respective grant dates. As part of the Transactions, half of the common units and override units in Coffeyville Acquisition LLC held by each named executive officer will be redeemed in exchange for an equal number of common units and override units in Coffeyville Acquisition II LLC so that, following the consummation of the Transactions, each named executive officer will hold equal numbers and types of limited liability interests in both Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. The common units and override units in Coffeyville Acquisition II LLC will have the same rights and obligations as the common units and override units in Coffeyville Acquisition LLC. Additionally, following the consummation of the Transactions, each named executive officer will hold the same number and type of phantom points under the Phantom Unit Plan II as he currently holds under the Phantom Unit Plan I. For a more detailed description of these plans, please see Executives Interests in Coffeyville Acquisition LLC and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II), below.

Additional phantom points were also awarded to each of the named executive officers (Messrs. Lipinski, Riemann, Rens, Haugen and Jernigan) in December 2006 pursuant to the Phantom Unit Plan I. The Phantom Unit Plan I had an unallocated pool of phantom points that were not initially issued. At the time of the acquisition of our business in 2005, there was an understanding among the Goldman Sachs Funds, the Kelso Funds and our management team that this pool would remain unallocated until a triggering event occurred. At the time the pool of phantom points was created in 2005 in respect of the Phantom Unit Plan I, the intent was that the triggering event would be an add-on acquisition of another business. If that had happened, new management would have been brought in, and the unallocated pool could have been used for that new management. However, no add-on acquisition occurred. The next most significant event that occurred was the filing of the registration statement, and we determined that this would be the triggering event to allocate the pool. The filing of the registration statement precipitated the action of the compensation committee to review and determine the allocation of the additional phantom points from the Phantom Unit Plan I for issuance.

Additionally, there was a pool of override units that had not been issued. It was also the intent that, upon a filing of a registration statement, the unallocated override units in the pool would be issued. The compensation committee recommended the issuance of all remaining override units in the pool available be issued to John J. Lipinski on December 28, 2006. The compensation committee made its decision and recommendation to the board of directors to grant Mr. Lipinski these additional units based on a number of accomplishments achieved by him over the past 18 months (and made the decision and recommendation without any input from Mr. Lipinski). Mr. Lipinski has been and will continue to be instrumental in positioning the company to become more competitive and to increase the capacity of the refinery operations through his negotiating and obtaining favorable crude oil pricing, as well as in helping to gain access to capital in order to expand overall operations of both segments of the business. The increased value and growth of the business is directly attributable to the actions and leadership that Mr. Lipinski has provided for the overall executive management group. Specific achievements include:

Significant operational improvement (in increased refinery throughput and yield) for an asset that emerged from bankruptcy just over 3 years ago, as described on page 2 of the prospectus. Upon assuming leadership of our company, Mr. Lipinski challenged existing management to optimize our refinery operations by focusing on plant operating limits each day. With over 35 years of experience in the refining and nitrogen fertilizer industries, Mr. Lipinski focused, and led management to focus, on the details of day-to-day plant operations. Previously, the refinery had primarily operated based on a predetermined monthly plan which resulted in significant unused capacity. The result of this revised focus was to immediately increase operating rates with essentially no capital expenditures being incurred.

Initiation of refined fuels offsite rack marketing, as described more fully on page 2 of this prospectus. Under Mr. Lipinski s direction and leadership, we have built our rack marketing sales sales of refined products made at terminals into third party tanker trucks, as opposed to sales through third party pipelines which has directly impacted and improved our profitability. Although we had the infrastructure in place to commence rack marketing, it had not been implemented at the time that Mr. Lipinski became chief executive officer in June 2005. Mr. Lipinski authorized additional company personnel to expand the rack marketing operation and it has served as a key factor in our company s success over the past two years.

Revised linear program model and focus on quality control. Mr. Lipinski authorized a project to revise our linear program model which we use for refinery planning and optimization. A linear program is a computer program that simulates plant operations and profitability based on different pricing and operating environment assumptions. Mr. Lipinski also directed that additional company resources be applied to quality assurance and quality control activities throughout the organization. As a result of these efforts, we now have a better modeling tool to assess plant operating rates, sales opportunities and crude oil purchases along with an improved understanding of our operations and better control over product quality.

Technical focus and environmental stewardship. After becoming chief executive officer, Mr. Lipinski recognized that our organization needed a more technical focus in order to achieve superior performance and he approved the hiring of additional engineering and technical staff, particularly with respect to process engineering. He also fostered a renewed focus on environmental stewardship (evidenced by the construction of our plant wide flare) and safety (evidenced by a reduction in lost time accidents and reportable incidents).

Implementation and initiation of a refinery expansion project, as further described on page 2. In connection with the due diligence review of our company prior to becoming our chief executive officer, Mr. Lipinski recognized that there was a significant opportunity to more fully

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utilize the facility s crude capacity by expanding our downstream units. After assuming his position as CEO, Mr. Lipinski sought approval of a project to expand the refinery s capacity to 115,000 barrels per day, compared to an average of less than 90,000 prior to June 2005. Through Mr. Lipinski s leadership, we substantially implemented this project in less than twenty-months and currently benefit from improved capacity throughout the plant.

Additionally, due to the significant contributions of Mr. Lipinski as reflected above, the compensation committee awarded him for his services 0.1044200 shares in Coffeyville Refining & Marketing, Inc. and 0.2125376 shares in Coffeyville Nitrogen Fertilizers, Inc. This approximates 0.31% and 0.64% of each company s total shares outstanding, respectively. The shares were issued to compensate him for his exceptional performance related to the operations of the business. In connection with the formation of Coffeyville Refining & Marketing Holdings, Inc., Mr. Lipinski s shares of common stock in Coffeyville Refining & Marketing, Inc. were exchanged for an equivalent number of shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. Prior to the consummation of this offering, we expect that these shares will be exchanged for shares of common stock in CVR Energy at an equivalent fair market value.

We also plan to establish a stock incentive plan in connection with the initial public offering. No awards have been established at this time for the chief executive officer or other named executive officers. In keeping with the compensation committee s stated philosophy, such awards will be intended to help achieve the compensation goals necessary to run our business.

Other Forms of Compensation

Each of our executive officers has a provision in his employment agreement providing for certain severance benefits in the event of termination without cause. These severance provisions are described in the Employment Agreements and Other Arrangements section below. The severance arrangements were all negotiated with the original employment agreements between the executive officer and the company. There are no change of control arrangements, but the compensation committee believed that there needed to be some form of compensation upon certain events of termination of services as is customary for similar companies.

As a general matter, we do not provide a significant number of perquisites to named executive officers. In April 2007, however, we paid our Chief Operating Officer, Stanley A. Riemann, approximately $220,000 as a relocation incentive for Mr. Riemann to relocate at our request to the Sugar Land, Texas area.

Compensation Policies and Philosophy

Ours is a commodity business with high volatility and risk where earnings are not only influenced by margins, but also by unique, innovative and aggressive actions and business practices on the part of the executive team. The compensation committee routinely reviews financial and operational performance compared to our business plan, positive and negative industry factors, and the response of the senior management team in dealing with and maximizing operational and financial performance in the face of otherwise negative situations. Due to the nature of our business, performance of an individual or the business as a whole may be outstanding; however, our financial performance may not depict this same level of achievement. The financial performance of the company is not necessarily reflective of individual operational performance. These are some of the factors used in setting executive compensation. Specific performance levels or benchmarks are not necessarily used to establish compensation; however, the compensation committee takes into account all factors to make a subjective determination of related compensation packages for the executive officers.

The compensation committee has not adopted any formal or informal policies or guidelines for allocating compensation between long-term and current compensation, between cash and non-cash compensation, or among different forms of compensation other than its belief that the most crucial component is equity compensation. The decision is strictly made on a subjective and individual basis considering all relevant facts.

For compensation decisions, including decisions regarding the grant of equity compensation relating to executive officers (other than our chief executive officer and chief operating officer), the compensation committee typically considers the recommendations of our chief executive officer.

In recommending compensation levels and practices, our management reviews peer group compensation practices based on publicly available data. The analysis is done in-house in its entirety and is reviewed by executive officers who are not members of the compensation committee. The analysis is based on public information available through proxy statements and similar sources. Because the analysis is almost always performed based on prior year public information, it may often be somewhat outdated. We have not historically and at this time do not intend to hire or rely on independent consultants to analyze or prepare formal surveys for us. We do receive certain unsolicited executive compensation surveys; however, our use of these is limited as we believe we need to determine our baseline based on practices of other companies in our industry.

After this registration statement is declared effective, Section 162(m) of the Internal Revenue Code will limit the deductibility of compensation in excess of $1 million paid out to our executive officers unless specific and detailed criteria are satisfied. We believe that it is in our best interest to deduct compensation paid to our executive officers. We will consider the anticipated tax treatment to the company and our executive officers in the review and determination of the compensation payments and incentives. No assurance, however, can be given that the compensation will be fully deductible under Section 162(m).

Following the completion of this offering, we will continue to reward executive officers through programs that enhance and emphasize performance-based incentives. We will continue our strategy to identify rewards that promote the objective of enhancing stockholder value. Executive compensation will continue to be structured to ensure that there is a balance between financial performance and stockholder returns as well as an appropriate balance between short-term and long-term performance.

Nitrogen Fertilizer Limited Partnership

A number of our executive officers, including our chief executive officer, chief operating officer, chief financial officer, general counsel, and executive vice president/general manager for nitrogen fertilizer, will serve as executive officers for both our company and the Partnership. These executive officers will receive all of their compensation and benefits from us, including compensation related to services for the Partnership, and will not be paid by the Partnership or its managing general partner. However, the Partnership or the managing general partner will reimburse us pursuant to a services agreement for the time our executive officers spend working for the Partnership. The percentage of each named executive officer s compensation that will represent the services provided to the Partnership will be approximately as follows: John J. Lipinski (10%), Stanley A. Riemann (25%), James T. Rens (20%), Robert W. Haugen (0%) and Wyatt E. Jernigan (0%).

We will enter into a services agreement with the Partnership and its managing general partner in which we will agree to provide management services to the Partnership for the operation of the nitrogen fertilizer business. Under this agreement any of the Partnership, its managing general partner or Coffeyville Resources Nitrogen Fertilizers, LLC, a subsidiary of the Partnership, will pay us (i) all costs incurred by us in connection with the employment of our employees, other than administrative personnel, who provide services to the Partnership under the agreement on a full-time basis, but excluding share-based compensation; (ii) a prorated share of costs incurred by us in connection with the employment of our employees, other than administrative personnel, who provide services to the Partnership under the agreement on a part-time basis, but excluding share-based compensation, and such prorated share shall be determined by us on a commercially reasonable basis, based on the percent of total working time that such shared personnel are engaged in performing services for the Partnership; (iii) a prorated share of certain administrative costs; and (iv) various other administrative costs in accordance with the terms of the agreement. Either we or the managing general partner of the Partnership may terminate the agreement upon at least 90 days notice. For more information on this services agreement, see The Nitrogen Fertilizer Limited Partnership Other Intercompany Agreements.

Prior to the consummation of this offering, the managing general partner of the Partnership intends to adopt the CVR Partners, LP Profit Bonus Plan, or the bonus plan, on behalf of the Partnership. The named executive officers will participate in the bonus plan. Payments under the bonus plan will relate to distributions made by Coffeyville Acquisition III LLC. Because we will be transferring our nitrogen fertilizer business to the Partnership from an entity in which the named executive officers previously held equity interests, this bonus plan is meant to pay bonuses in respect of that business now that it has moved to a different owner. For more information on the bonus plan, see Employment Agreements and Other Arrangements CVR Partners, LP Profit Bonus Plan.

Summary Compensation Table

The following table sets forth certain information with respect to compensation for the year ended December 31, 2006 earned by our chief executive officer, our chief financial officer and our three other most highly compensated executive officers as of December 31, 2006. In this prospectus, we refer to these individuals as our named executive officers.

Name and Principal Position	Year	Salary ($)	Bonus ($) (1)	Stock Awards ($)	Non-Equity Incentive Plan Compensation ($) (1)(4)	All Other Compensation ($)	Total ($)
John J. Lipinski Chief Executive Officer	2006	650,000	1,331,790	4,326,188(3)	487,500	5,007,935(5)(6)	11,803,413
Stanley A. Riemann Chief Operating Officer	2006	350,000	772,917(2)		210,000	943,789(5)(7)	2,276,706
James T. Rens Chief Financial Officer	2006	250,000	205,000		130,000	695,316(5)(8)	1,280,316
Robert W. Haugen Executive Vice President, Refining Operations	2006	225,000	205,000		117,000	695,471(5)(9)	1,242,471
Wyatt E. Jernigan Executive Vice President Crude Oil Acquisition and Petroleum Marketing	2006	225,000	140,000		117,000	318,000(5)(10)	800,000

(1) Bonuses are reported for the year in which they were earned, though they may have been paid the following year.

(2) Includes a retention bonus in the amount of $122,917.

(3) Reflects the amount recognized for financial statement reporting purposes for the fiscal year ended December 31, 2006 with respect to shares of common stock of each of Coffeyville Refining and Marketing, Inc. and Coffeyville Nitrogen Fertilizer, Inc. granted to Mr. Lipinski effective December 28, 2006.

(4) Reflects cash awards to the named individuals in respect of 2006 performance pursuant to our Variable Compensation Plan.

(5) The amounts shown representing grants of profits interests in Coffeyville Acquisition LLC and phantom points reflect the dollar amounts recognized for financial statement reporting purposes for the year ended December 31, 2006 in accordance with FAS 123(R). Assumptions used in the calculation of these amounts are included in footnote 5 to our audited financial statements for the year ended December 31, 2006. The profits interests in Coffeyville Acquisition LLC and the phantom points are more fully described below under Executives Interests in Coffeyville Acquisition LLC.

(6) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) forgiveness of a note that Mr. Lipinski owed to Coffeyville Acquisition LLC in the amount of $350,000, (d) forgiveness of accrued interest related to the forgiven note in the amount of $17,989, (e) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $630,059, (f) a cash payment in respect of taxes payable on his December 28, 2006 grant of subsidiary stock in the amount of $2,481,346, (g) profits interests in Coffeyville Acquisition LLC that were granted December 28, 2006 in the amount of $20,510 and (h) phantom points granted during the period ending December 31, 2006 in the amount of $1,495,211.

(7) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $279,670 and (d) phantom points granted to Mr. Riemann during the period ending December 31, 2006 in the amount of $651,299.

(8) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $143,571 and (d) phantom points granted to Mr. Rens during the period ending December 31, 2006 in the amount of $541,061.

(9) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $143,571 and (d) phantom points granted to Mr. Haugen during the period ending December 31, 2006 in the amount of $541,061.

(10) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $143,571 and (d) phantom points granted to Mr. Jernigan during the period ending December 31, 2006 in the amount of $162,319.

Grants of Plan-Based Awards

Name	Grant Date	All other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Option Awards
John J. Lipinski	December 28, 2006	(1)	$4,326,188(1)
	December 28, 2006	217,458(2)	$1,417,826(4)
	December 11, 2006	2,737,142(3)	$4,252,562(4)
Stanley A. Riemann	December 11, 2006	1,192,266(3)	$1,852,367(4)
James T. Rens	December 11, 2006	990,476(3)	$1,538,851(4)
Robert W. Haugen	December 11, 2006	990,476(3)	$1,538,851(4)
Wyatt E. Jernigan	December 11, 2006	297,142(3)	$461,656(4)

(1) Mr. Lipinski received a grant of shares of common stock of each of Coffeyville Refining and Marketing, Inc. and Coffeyville Nitrogen Fertilizer, Inc. effective December 28, 2006. The number of shares of Coffeyville Nitrogen Fertilizer, Inc. granted was 0.2125376, which equaled approximately 0.64% of the total shares outstanding. The number of shares of Coffeyville Refining and Marketing, Inc. granted was 0.1044200, which approximated 0.31% of the total shares outstanding. The dollar amount shown reflects the grant date fair value recognized for financial

statement reporting purposes in accordance with FAS 123(R). Assumptions used in the calculation of these amounts are included in footnote 5 to our audited financial statements for the year ended December 31, 2006.

(2) Represents the number of profits interests in Coffeyville Acquisition LLC granted to the executive on December 28, 2006.

(3) Represents the number of phantom points granted to the executive on December 11, 2006.

(4) The dollar amount shown reflects the fair value as of December 31, 2006 recognized for financial reporting purposes in accordance with FAS 123(R). Assumptions used in the calculation of this amount are included in footnote 5 to our audited financial statements for the year ended December 31, 2006.

Employment Agreements and Other Arrangements

Employment Agreements

John J. Lipinski. On July 12, 2005, Coffeyville Resources, LLC entered into an employment agreement with Mr. Lipinski, as Chief Executive Officer. The agreement has a rolling term of three years so that at the end of each month it automatically renews for one additional month, unless otherwise terminated by Coffeyville Resources, LLC or Mr. Lipinski. Mr. Lipinski receives an annual base salary of $650,000. Mr. Lipinski is eligible to receive a performance-based annual cash bonus with a target payment equal to 75% (250% effective January 1, 2007) of his annual base salary to be based upon individual and/or company performance criteria as established by the board of directors of Coffeyville Resources, LLC for each fiscal year. For years prior to 2007, in addition to his annual bonus, Mr. Lipinski was eligible to participate in any special bonus program that the board of directors of Coffeyville Resources, LLC implemented to reward senior management for extraordinary performance on terms and conditions established by such board.

Mr. Lipinski s agreement provides for certain severance payments that may be due following the termination of his employment. These benefits are described below under Change-in-Control and Termination Payments.

Stanley A. Riemann, James T. Rens, Robert W. Haugen and Wyatt E. Jernigan. On July 12, 2005, Coffeyville Resources, LLC entered into employment agreements with each of Mr. Riemann, as Chief Operating Officer; Mr. Rens, as Chief Financial Officer; Mr. Haugen, as Executive Vice President Engineering and Construction; and Mr. Jernigan, as Executive Vice President Crude Oil Acquisition and Petroleum Marketing. The agreements have a term of three years and expire on June 24, 2008, unless otherwise terminated earlier by the parties. The agreements provide for an annual base salary of $350,000 for Mr. Riemann, $250,000 for Mr. Rens, $225,000 for Mr. Haugen ($275,000 effective January 1, 2007) and $225,000 for Mr. Jernigan. Each executive officer is eligible to receive a performance-based annual cash bonus with a target payment equal to 52% of his annual base salary (60% for Mr. Riemann) to be based upon individual and/or company performance criteria as established by the board of directors of Coffeyville Resources, LLC for each fiscal year. Effective January 1, 2007, the target annual bonus percentages are as follows: Mr. Reimann (200%), Mr. Rens (120%), Mr. Haugen (120%) and Mr. Jernigan (100%). For years prior to 2007, in addition to their annual bonuses, the executives were eligible to participate in any special bonus program that the board of directors of Coffeyville Resources, LLC implemented to reward senior management for extraordinary performance on terms and conditions established by the board of directors of Coffeyville Resources, LLC. Mr. Riemann s agreement provides that he will receive retention bonuses of approximately $245,833 in the aggregate during the years 2006 and 2007.

These agreements provide for certain severance payments that may be due following the termination of the executive officers employment. These benefits are described below under Change-in-Control and Termination Payments.

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Long Term Incentive Plan

Prior to the completion of this offering, we intend to adopt the CVR Energy, Inc. 2007 Long Term Incentive Plan, or the LTIP, to permit the grant of options, stock appreciation rights, or SARs, restricted stock, restricted stock units, dividend equivalent rights, share awards and performance awards (including performance share units, performance units and performance-based restricted stock). Individuals who will be eligible to receive awards and grants under the LTIP include our and our subsidiaries employees, officers, consultants, advisors and directors. A summary of the principal features of the LTIP is provided below.

Shares Available for Issuance

The LTIP authorizes a share pool of 7,500,000 shares of our common stock, 1,000,000 of which may be issued in respect of incentive stock options. Whenever any outstanding award granted under the LTIP expires, is canceled, is settled in cash or is otherwise terminated for any reason without having been exercised or payment having been made in respect of the entire award, the number of shares available for issuance under the LTIP shall be increased by the number of shares previously allocable to the expired, canceled, settled or otherwise terminated portion of the award.

Administration and Eligibility

The LTIP would be administered by a committee, which would initially be the compensation committee. The committee would determine who is eligible to participate in the LTIP, determine the types of awards to be granted, prescribe the terms and conditions of all awards, and construe and interpret the terms of the LTIP. All decisions made by the committee would be final, binding and conclusive.

Award Limits

In any three calendar year period, no participant may be granted awards in respect of more than 6,000,000 shares in the form of (i) stock options, (ii) SARs, (iii) performance-based restricted stock and (iv) performance share units, with the above limit subject to the adjustment provisions discussed below. The maximum dollar amount of cash or the fair market value of shares that any participant may receive in any calendar year in respect of performance units may not exceed $3,000,000.

Type of Awards

Stock Options. The compensation committee is authorized to grant stock options to participants. The stock options may be either nonqualified stock options or incentive stock options. The exercise price of any stock option must be equal to or greater than the fair market value of a share on the date the stock option is granted. The term of a stock option cannot exceed ten (10) years (except that options may be exercised for up to one (1) year following the death of a participant even, with respect to nonqualified stock options, if such period extends beyond the ten (10) year term). Subject to the terms of the LTIP, the option s terms and conditions, which include but are no limited to, exercise price, vesting, treatment of the award upon termination of employment, and expiration of the option, would be determined by the committee and set forth in an award agreement. Payment for shares purchased upon exercise of an option must be made in full at the time of purchase. The exercise price may be paid (i) in cash or its equivalent (e.g., check), (ii) in shares of our common stock already owned by the participant, on terms determined by the committee, (iii) in the form of other property as determined by the committee, (iv) through participation in a cashless exercise procedure involving a broker or (v) by a combination of the foregoing.

SARS. The compensation committee may, in its discretion, either alone or in connection with the grant of an option, grant a SAR to a participant. The terms and conditions of the award would be set forth in an award agreement. SARs may be exercised at such times and be subject to such other terms, conditions, and provisions as the committee may impose. SARs that are granted in tandem with an option may only be exercised upon the surrender of the right to purchase an equivalent number of shares of our common stock under the related option and may be exercised only with respect to the shares of our common stock for which the related option is then exercisable. The committee may establish a maximum amount per share that would be payable upon exercise of a SAR. A SAR would entitle the participant to receive, on exercise of the SAR, an amount equal to the product of (i) the excess of the fair market value of a share of our common stock on the date preceding the date of surrender over the fair market value of a share of our common stock on the date the SAR was issued, or, if the SAR is related to an option, the per-share exercise price of the option and (ii) the number of shares of our common stock subject to the SAR or portion thereof being exercised. Subject to the discretion of the committee, payment of a SAR may be made (i) in cash, (ii) in shares of our common stock or (iii) in a combination of both (i) and (ii).

Dividend Equivalent Rights. The compensation committee may grant dividend equivalent rights either in tandem with an award or as a separate award. The terms and conditions applicable to each dividend equivalent right would be specified in an award agreement. Amounts payable in respect of dividend equivalent rights may be payable currently or, if applicable, deferred until the lapsing of restrictions on the dividend equivalent rights or until the vesting, exercise, payment, settlement or other lapse of restrictions on the award to which the dividend equivalent rights relate.

Service Based Restricted Stock and Restricted Stock Units. The compensation committee may grant awards of time-based restricted stock and restricted stock units. Restricted stock and restricted stock units may not be sold, transferred, pledged, or otherwise transferred until the time, or until the satisfaction of such other terms, conditions, and provisions, as the committee may determine. When the period of restriction on restricted stock terminates, unrestricted shares of our common stock would be delivered. Unless the committee otherwise determines at the time of grant, restricted stock carries with it full voting rights and other rights as a stockholder, including rights to receive dividends and other distributions. At the time an award of restricted stock is granted, the committee may determine that the payment to the participant of dividends would be deferred until the lapsing of the restrictions imposed upon the shares and whether deferred dividends are to be converted into additional shares of restricted stock or held in cash. The deferred dividends would be subject to the same forfeiture restrictions and restrictions on transferability as the restricted stock with respect to which they were paid. Each restricted stock unit would represent the right of the participant to receive a payment upon vesting of the restricted stock unit or on any later date specified by the committee. The payment would equal the fair market value of a share of common stock as of the date the restricted stock unit was granted, the vesting date, or such other date as determined by the committee at the time the restricted stock unit was granted. At the time of grant, the committee may provide a limitation on the amount payable in respect of each restricted stock unit. The committee may provide for a payment in respect of restricted stock unit awards (i) in cash or (ii) in shares of our common stock having a fair market value equal to the payment to which the participant has become entitled.

Share Awards. The compensation committee may award shares to participants as additional compensation for service to us or a subsidiary or in lieu of cash or other compensation to which participants have become entitled. Share awards may be subject to other terms and conditions, which may vary from time to time and among participants, as the committee determines to be appropriate.

Performance Share Units and Performance Units. Performance share unit awards and performance unit awards may be granted by the compensation committee under the LTIP. Performance share units are denominated in shares and represent the right to receive a payment in an amount based on the fair market value of a share on the date the performance share units were granted, become vested or any other date specified by the committee, or a percentage of such amount depending on the level of performance goals attained. Performance units are denominated in a specified dollar amount and represent the right to receive a payment of the specified dollar amount or a percentage of the specified dollar amount, depending on the level of performance goals attained. Such awards would be earned only if performance goals established for performance periods are met. A minimum one-year performance period is required. At the time of grant the committee may establish a maximum amount payable in respect of a vested performance share or performance unit. The committee may provide for payment (i) in cash, (ii) in shares of our common stock having a fair

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market value equal to the payment to which the participant has become entitled or (iii) by a combination of both (i) and (ii).

Performance-Based Restricted Stock. The compensation committee may grant awards of performance-based restricted stock. The terms and conditions of such award would be set forth in an award agreement. Such awards would be earned only if performance goals established for performance periods are met. Upon the lapse of the restrictions, the committee would deliver a stock certificate or evidence of book entry shares to the participant. Awards of performance-based restricted stock would be subject to a minimum one-year performance cycle. At the time an award of performance-based restricted stock is granted, the committee may determine that the payment to the participant of dividends would be deferred until the lapsing of the restrictions imposed upon the performance-based restricted stock and whether deferred dividends are to be converted into additional shares of performance-based restricted stock or held in cash.

Performance Objectives

Performance share units, performance units and performance-based restricted stock awards under the LTIP may be made subject to the attainment of performance goals based on one or more of the following business criteria: (i) stock price; (ii) earnings per share; (iii) operating income; (iv) return on equity or assets; (v) cash flow; (vi) earnings before interest, taxes, depreciation and amortization, or EBITDA; (vii) revenues; (viii) overall revenue or sales growth; (ix) expense reduction or management; (x) market position; (xi) total stockholder return; (xii) return on investment; (xiii) earnings before interest and taxes, or EBIT; (xiv) net income; (xv) return on net assets; (xvi) economic value added; (xvii) stockholder value added; (xviii) cash flow return on investment; (xix) net operating profit; (xx) net operating profit after tax; (xxi) return on capital; (xxii) return on invested capital; or (xxiii) any combination, including one or more ratios, of the foregoing.

Performance criteria may be in respect of our performance, that of any of our subsidiaries, that of any of our divisions or any combination of the foregoing. Performance criteria may be absolute or relative (to our prior performance or to the performance of one or more other entities or external indices) and may be expressed in terms of a progression within a specified range. The compensation committee may, at the time performance criteria in respect of a performance award are established, provide for the manner in which performance will be measured against the performance criteria to reflect the effects of extraordinary items, gain or loss on the disposal of a business segment (other than the provisions for operating losses or income during the phase-out), unusual or infrequently occurring events and transactions that have been publicly disclosed, changes in accounting principles, the impact of specified corporate transactions (such as a stock split or stock divided), special charges and tax law changes, all as determined in accordance with generally accepted accounting principles (to the extent applicable).

Amendment and Termination of the LTIP

Our board of directors has the right to amend the LTIP except that our board of directors may not amend the LTIP in a manner that would impair or adversely affect the rights of the holder of an award without the award holder s consent. In addition, our board of directors may not amend the LTIP absent stockholder approval to the extent such approval is required by applicable law, regulation or exchange requirement. The LTIP will terminate on the tenth anniversary of the date of stockholder approval. The board of directors may terminate the LTIP at any earlier time except that termination cannot in any manner impair or adversely affect the rights of the holder of an award without the award holder s consent.

Repricing of Options or SARs

Unless our stockholders approve such adjustment, the compensation committee would not have authority to make any adjustments to options or SARs that would reduce or would have the effect of reducing the exercise price of an option or SAR previously granted under the LTIP.

Change in Control

The effect, if any, of a change in control on each of the awards granted under the LTIP may be set forth in the applicable award agreement.

Adjustments

In the event of a reclassification, recapitalization, merger, consolidation, reorganization, spin-off, split-up, stock dividend, stock split or reverse stock split, or similar transaction or other change in corporate structure affecting our common stock, adjustments and other substitutions will be made to the LTIP, including adjustments in the maximum number of shares subject to the LTIP and other numerical limitations. Adjustments will also be made to awards under the LTIP as the compensation committee determines appropriate. In the event of our merger or consolidation, liquidation or dissolution, outstanding options and awards will either be treated as provided for in the agreement entered into in connection with the transaction (which may include the accelerated vesting and cancellation of the options and SARs or the cancellation of options and SARs for payment of the excess, if any, of the consideration paid to stockholders in the transaction over the exercise price of the options or SARs), or converted into options or awards in respect of the same securities, cash, property or other consideration that stockholders received in connection with the transaction.

Executives Interests in Coffeyville Acquisition LLC

The following is a summary of the material terms of the Coffeyville Acquisition LLC Second Amended and Restated Limited Liability Company Agreement, or the LLC Agreement, as they relate to the limited liability company interests granted to our named executive officers pursuant to the LLC Agreement as of December 31, 2006.

As part of the Transactions, half of the common units and override units in Coffeyville Acquisition LLC held by each executive officer will be redeemed in exchange for an equal number of common units and override units in Coffeyville Acquisition II LLC so that, following the consummation of the Transactions, such executive officer will hold an equal number and type of limited liability interests in both Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. The common units and override units in Coffeyville Acquisition II LLC will have the same rights and obligations as the common units and override units in Coffeyville Acquisition LLC.

General

The LLC Agreement provides for two classes of interests in Coffeyville Acquisition LLC: (i) common units and (ii) profits interests, which are called override units (which consist of either operating units or value units) (common units and override units are collectively referred to as units). The common units provide for voting rights and have rights with respect to profits and losses of, and distributions from, Coffeyville Acquisition LLC. Such voting rights cease, however, if the executive officer holding common units ceases to provide services to Coffeyville Acquisition LLC or one of its subsidiaries. The common units were issued to our named executive officers in the following amounts (as subsequently adjusted) in exchange for capital contributions in the following amounts: Mr. Lipinski (capital contribution of $650,000 in exchange for 57,446 units), Mr. Riemann (capital contribution of $400,000 in exchange for 35,352 units), Mr. Rens (capital contribution of $250,000 in exchange for 22,095 units), Mr. Haugen (capital contribution of $100,000 in exchange for 8,838 units) and Mr. Jernigan (capital contribution of $100,000 in exchange for 8,838 units). These named executive officers were also granted override units, which consist of operating units and value units, in the

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following amounts: Mr. Lipinski (an initial grant of 315,818 operating units and 631,637 value units and a December 2006 grant of 72,492 operating units and 144,966 value units), Mr. Riemann (140,185 operating units and 280,371 value units), Mr. Rens (71,965 operating units and 143,931 value units), Mr. Haugen (71,965 operating units and 143,931 value units) and Mr. Jernigan (71,965 operating units and 143,931 value units). Override units have no voting rights attached to them, but have rights with respect to profits and losses of, and distributions from, Coffeyville Acquisition LLC. Our named executive officers were not required to make any capital contribution with respect to the override units; override units were issued only to certain members of management who own common units and who agreed to provide services to Coffeyville Acquisition LLC.

In addition, common units were issued to the following executive officers in the following amounts (as subsequently adjusted) in exchange for the following capital contributions: Mr. Kevan Vick (capital contribution of $250,000 in exchange for 22,095 units), Mr. Edmund Gross (capital contribution of $30,000 in exchange for 2,651 units) and Mr. Chris Swanberg (capital contribution of $25,000 in exchange for 2,209 units). Mr. Vick was also granted 71,965 operating units and 143,931 value units.

If all of the shares of common stock of our Company held by Coffeyville Acquisition LLC were sold at the initial public offering price of $19.00 per share and cash was distributed to members pursuant to the LLC Agreement, our named executive officers would receive a cash payment in respect of their override units in the following approximate amounts: Mr. Lipinski ($49.1 million), Mr. Riemann ($19.6 million), Mr. Rens ($10.1 million), Mr. Haugen ($10.1 million), and Mr. Jernigan ($10.1 million).

Forfeiture of Override Units Upon Termination of Employment

If the executive officer ceases to provide services to Coffeyville Acquisition LLC or a subsidiary due to a termination for cause (as such term is defined in the LLC Agreement), the executive officer will forfeit all of his override units. If the executive officer ceases to provide services for any reason other than cause before the fifth anniversary of the date of grant of his operating units, and provided that an event that is an Exit Event (as such term is defined in the LLC Agreement) has not yet occurred and there is no definitive agreement in effect regarding a transaction that would constitute an Exit Event, then (a) unless the termination was due to the executive officer s death or disability (as that term is defined in the LLC Agreement), in which case a different vesting schedule will apply based on when the death or disability occurs, all value units will be forfeited and (b) a percentage of the operating units will be forfeited according to the following schedule: if terminated before the second anniversary of the date of grant, 100% of operating units are forfeited; if terminated on or after the second anniversary of the date of grant, but before the third anniversary of the date of grant, 75% of operating units are forfeited; if terminated on or after the third anniversary of the date of grant, but before the fourth anniversary of the date of grant, 50% of operating units are forfeited; and if terminated on or after the fourth anniversary of the date of grant, but before the fifth anniversary of the date of grant, 25% of his operating units are forfeited. Following the consummation of this offering, we understand that Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC may amend their respective limited liability company agreements to vest a significant portion of the override units issued under the agreements in recognition of the success of the offering. If the vesting of these override units is accelerated, then the unrecognized compensation expense relating to these override units would be subject to accelerated recognition.

Adjustments to Capital Accounts; Distributions

Each of the executive officers has a capital account under which his balance is increased or decreased, as applicable, to reflect his allocable share of net income and gross income of Coffeyville Acquisition LLC, the capital that the executive officer contributed, distributions paid to such executive officer and his allocable share of net loss and items of gross deduction.

Value units owned by the executive officers do not participate in distributions under the LLC Agreement until the Current Value is at least two times the Initial Price (as these terms are defined in the LLC Agreement), with full participation occurring when the Current Value is four times the Initial Price and pro rata distributions when the Current Value is between two and four times the Initial Price. Coffeyville Acquisition LLC may make distributions to its members to the extent that the cash available to it is in excess of the business s reasonably anticipated needs. Distributions are generally made to members capital accounts in proportion to the number of units each member holds. Distributions in respect of override units (both operating units and value units), however, will be reduced until the total reductions in proposed distributions in respect of the override units equals the Benchmark Amount (i.e., $11.31 for override units granted on July 25, 2005 and $34.72 for Mr. Lipinski s later grant). The board of directors of Coffeyville Acquisition LLC will determine the Benchmark Amount with respect to each override unit at the time of its grant. There is also a catch-up provision with respect to any value unit that was not previously entitled to participate in a distribution because the Current Value was not at least four times the Initial Price.

Other Provisions Relating to Units

The executive officers are subject to transfer restrictions on their units, although they may make certain transfers of their units for estate planning purposes.

Executives Interests in Coffeyville Acquisition III LLC

Following the consummation of this offering, Coffeyville Acquisition III LLC, the sole parent of the managing general partner of the Partnership, will be owned by the Goldman Sachs Funds, the Kelso Funds, our executive officers, Mr. Wesley Clark, Magnetite Asset Investors III L.L.C. and other members of our management. The terms of the limited liability company agreement for Coffeyville Acquisition III LLC will be substantially the same as the terms of the LLC Agreement except that there will be a single class of override units and such override units will have the same rights as value units under the LLC Agreement, will have rights with respect to profits and losses of, and distributions from, Coffeyville Acquisition III LLC, will not be subject to forfeiture upon termination of employment and will fully participate in distributions by Coffeyville Acquisition III LLC when the Current Value is at least equal to the Initial Price (as these terms will be defined in the Limited Liability Company Agreement of Coffeyville Acquisition III LLC).

Our executive officers will make the following capital contributions to Coffeyville Acquisition III LLC and will receive a number of common units equal to their pro rata portion of the total $10.6 million contributed: Mr. Lipinski ($68,146), Mr. Riemann ($16,359), Mr. Rens ($10,225), Mr. Gross ($1,227), Mr. Haugen ($4,090), Mr. Jernigan ($4,090), Mr. Vick ($10,225) and Mr. Swanberg ($1,022). The managing general partner also intends to award value units to these officers in amounts to be determined.

Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II)

The following is a summary of the material terms of the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I), or the Phantom Unit Plan I, and the Coffeyville Resources LLC Phantom Unit Appreciation Plan (Plan II), or the Phantom Unit Plan II, as they relate or will relate to our named executive officers. Payments under the Phantom Unit Plan I are tied to distributions made by Coffeyville Acquisition LLC, and payments under the Phantom Unit Plan II will be tied to distributions made by Coffeyville Acquisition II LLC.

In connection with the Transactions and prior to the consummation of this offering, because our named executive officers will hold interests in both Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, we intend to adopt the Phantom Unit Plan II at Coffeyville Resources, LLC which will be tied to distributions made by Coffeyville Acquisition II LLC and be parallel to the Phantom Unit Plan I. The rights and obligations under the Phantom Unit

Plan II with respect to Coffeyville Acquisition II LLC will be the same as the rights and obligations under the Phantom Unit Plan I with

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respect to Coffeyville Acquisition LLC. The following description generally reflects only the terms of the Phantom Unit Plan I, but the Phantom Unit Plan II will have parallel provisions.

General

The Phantom Unit Plan I is administered by the compensation committee of the board of directors of Coffeyville Acquisition LLC. The Phantom Unit Plan I provides for two classes of interests: phantom service points and phantom performance points (collectively referred to as phantom points). Holders of the phantom service points and phantom performance points have the opportunity to receive a cash payment when distributions are made pursuant to the LLC Agreement in respect of operating units and value units, respectively. The phantom points represent a contractual right to receive a payment when payment is made in respect of certain profits interests in Coffeyville Acquisition LLC. Phantom points have been granted to our named executive officers in the following amounts: Mr. Lipinski (1,368,571 phantom service points and 1,368,571 phantom performance points, which represents 13.7% of the total phantom points awarded), Mr. Riemann (596,133 phantom service points and 596,133 phantom performance points, which represents 6.0% of the total phantom points awarded), Mr. Rens (495,238 phantom service points and 495,238 phantom performance points, which represents 5.0% of the total phantom points awarded), Mr. Haugen (495,238 phantom service points and 495,238 phantom performance points, which represents 5.0% of the total phantom points awarded) and Mr. Jernigan (148,571 phantom service points and 148,571 phantom performance points, which represents 1.5% of the total phantom points awarded). Our named executive officers will receive phantom points under the Phantom Unit Plan II in the same amounts. If all of the shares of common stock of our company held by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC were sold at the initial public offering price of $19.00 per share and cash was distributed to members pursuant to the LLC Agreement and the Coffeyville Acquisition II LLC Agreement, our named executive officers would receive a cash payment in respect of their phantom points in the following amounts: Mr. Lipinski ($6.7 million), Mr. Riemann ($2.9 million), Mr. Rens ($2.4 million), Mr. Haugen ($2.4 million) and Mr. Jernigan ($0.7 million). The compensation committee of the board of directors of Coffeyville Acquisition LLC has authority to make additional awards of phantom points under the Phantom Unit Plan I.

Phantom Point Payments

Payments in respect of phantom service points will be made within 30 days from the date distributions are made pursuant to the LLC Agreement in respect of operating units. Cash payments in respect of phantom performance points will be made within 30 days from the date distributions are made pursuant to the LLC Agreement in respect of value units (i.e., not until the Current Value is at least two times the Initial Price (as such terms are defined in the LLC Agreement), with full participation occurring when the Current Value is four times the Initial Price and pro rata distributions when the Current Value is between two and four times the Initial Price). There is also a catch-up provision with respect to phantom performance points for which no cash payment was made because no distribution pursuant to the LLC Agreement was made with respect to value units.

Following the completion of this offering, Coffeyville Acquisition LLC may make a significant revision to the Phantom Unit Plan I (and, in turn, the Phantom Unit Plan II) to provide that a significant portion of the payments in respect of phantom service points and phantom performance points will be paid on fixed payment dates (for example, in annual installments) rather than within 30 days from the date distributions are made pursuant to the LLC Agreement. Coffeyville Acquisition LLC has indicated that it is continuing to explore other ways to revise the Phantom Unit Plans.

Other Provisions Relating to the Phantom Points

The board of directors of Coffeyville Acquisition LLC may, at any time or from time to time, amend or terminate the Phantom Unit Plan I. If a participant s employment is terminated prior to an Exit Event (as such term is defined in the LLC Agreement), all of the participant s phantom points

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are forfeited. Phantom points are generally non-transferable (except by will or the laws of descent and distribution). If payment to a participant in respect of his phantom points would result in the application of the excise tax imposed under Section 4999 of the Internal Revenue Code of 1986, as amended, then the payment will be cut back so that it will no longer be subject to the excise tax. Prior to the completion of this offering, Coffeyville Acquisition LLC intends to amend the Phantom Unit Plan I (and in turn, the Phantom Unit Plan II) so that a participant s payments will be cut back only if that reduction would be more beneficial to the participant on an after-tax basis than if there were no reduction.

CVR Partners, LP Profit Bonus Plan

The following is a summary of the material terms of the CVR Partners, LP Profit Bonus Plan, or the bonus plan, which the managing general partner of the Partnership intends to adopt on behalf of the Partnership prior to the consummation of this offering, as those terms relate to our named executive officers. Payments under the bonus plan will relate to distributions made by Coffeyville Acquisition III LLC.

General

The bonus plan will be administered by the compensation committee of the managing general partner of the Partnership on behalf of the Partnership. The bonus plan provides a class of interests called bonus points. Holders of bonus points will receive a cash payment when distributions of profit are made pursuant to the Coffeyville Acquisition III Limited Liability Company Agreement, or the Coffeyville Acquisition III LLC Agreement. The bonus points represent a contractual right to receive a payment when a profit distribution is made to the holders of the interests in Coffeyville Acquisition III LLC. The managing general partner of the Partnership intends to allocate bonus points to our named executive officers when the bonus plan is adopted. 1,000,000 bonus points will be available for grant under the bonus plan. Any employee of Coffeyville Resources Nitrogen Fertilizers, LLC or any of its affiliates, or any employee of any entity providing services to the Partnership or Coffeyville Resources Nitrogen Fertilizers, LLC, is eligible to participate. The compensation committee of the managing general partner of the Partnership will have the authority to make initial awards and additional awards in the future. CVR will not make any direct payments under this plan.

Bonus Point Payments

Payments in respect of bonus points will be made within 30 days from the date distributions of profit are made pursuant to the Coffeyville Acquisition III LLC Agreement. When each distribution is made, a bonus pool will be created which will equal 4.069% of the profits distributed. If such a distribution is made and the bonus pool is funded, participants will share proportionately in the pool based on the percentage of the available bonus points they were granted in relation to the total number of bonus points issued, unless their award agreements limit the amount payable in respect of their bonus points to an amount less than their pro rata share.

Other Provisions Relating to the Bonus Points

The managing general partner of the Partnership may, at any time or from time to time, amend or terminate the plan. If a participant s employment is terminated, all of the participant s bonus points are forfeited. Bonus points are non-transferable. If payment to a participant in respect of bonus points would result in the application of the excise tax imposed under Section 4999 of the Internal Revenue Code of 1986, as amended, then the payment will be cut back so that it will no longer be subject to the excise tax only if that reduction would be more beneficial to the participant on an after-tax basis than if there were no reduction.

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Outstanding Equity Awards at Fiscal Year End

	Stock Awards		
Name	**Number of Shares or Units of Stock That Have Not Vested (1) (2) (12)**		**Market Value of Shares or Units of Stock That Have Not Vested (11)**
John J. Lipinski	947,455(3)	$	28,038,350
	217,458(4)	$	1,417,826
	2,737,142(5)	$	4,252,562
Stanley A. Riemann	420,556(6)	$	12,445,652
	1,192,266(7)	$	1,852,367
James T. Rens	215,896(8)	$	6,389,080
	990,476(9)	$	1,538,851
Robert W. Haugen	215,896(8)	$	6,389,080
	990,476(9)	$	1,538,851
Wyatt E. Jernigan	215,896(8)	$	6,389,080
	297,142(10)	$	461,656

(1) The profits interests in Coffeyville Acquisition LLC generally vest as follows: operating units generally become non-forfeitable in 25% annual increments beginning on the second anniversary of the date of grant, and value units are generally forfeitable upon termination of employment. The profits interests are more fully described above under Executives Interests in Coffeyville Acquisition LLC.

(2) The phantom points granted pursuant to the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) are generally forfeitable upon termination of employment. The phantom points are more fully described above under Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II).

(3) Represents profits interests in Coffeyville Acquisition LLC (315,818 operating units and 631,637 value units) granted to the executive on June 24, 2005. These profits interests have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(4) Represents profits interests in Coffeyville Acquisition LLC (72,492 operating units and 144,966 value units) granted to the executive on December 28, 2006. These profits interests have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(5) Represents phantom points (1,368,571 phantom service points and 1,368,571 phantom performance points) granted to the executive on December 11, 2006.

(6) Represents profits interests in Coffeyville Acquisition LLC (140,185 operating units and 280,371 value units) granted to the executive on June 24, 2005.

(7) Represents phantom points (596,133 phantom service points and 596,133 phantom performance points) granted to the executive on December 11, 2006.

(8) Represents profits interests in Coffeyville Acquisition LLC (71,965 operating units and 143,931 value units) granted to the executive on June 24, 2005.

(9) Represents phantom points (495,238 phantom service points and 495,238 phantom performance points) granted to the executive on December 11, 2006.

(10) Represents phantom points (148,571 phantom service points and 148,571 phantom performance points) granted to the executive on December 11, 2006.

(11) The dollar amount shown reflects the fair value as of December 31, 2006, based upon an independent valuation prepared with a combination of a binomial model and a probability-weighted expected return method. Assumptions used in the calculation of this amount are included in footnote 5 to our audited financial statements for the year ended December 31, 2006.

(12) Following the consummation of the Transactions, each of the named executive officers will hold half of the number of profits interests set forth above in each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC.

Option Exercises and Stock Vested

Name	Stock Awards Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
John J. Lipinski	(1)	4,326,188(1)

(1) Mr. Lipinski received a grant of shares of common stock of each of Coffeyville Refining and Marketing, Inc. and Coffeyville Nitrogen Fertilizer, Inc. effective December 28, 2006. These shares were fully vested as of the date of grant. The number of shares of Coffeyville Nitrogen Fertilizer, Inc. granted was 0.2125376, which approximated 0.64% of the total shares outstanding. The number of shares of Coffeyville Refining and Marketing, Inc. granted was 0.1044200, which approximated 0.31% of the total shares outstanding. In connection with the formation of Coffeyville Refining & Marketing Holdings, Inc., Mr. Lipinski s shares of common stock in Coffeyville Refining & Marketing, Inc. were exchanged for an equivalent number of shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. Prior to the consummation of this offering, Mr. Lipinski s shares of common stock of each of Coffeyville Refining and Marketing Holdings, Inc. and Coffeyville Nitrogen Fertilizer, Inc. will be exchanged for shares of common stock of CVR Energy having an equivalent value.

Change-in-Control and Termination Payments

Severance Benefits Provided Pursuant to Employment Agreements

Under the terms of their respective employment agreements, the named executive officers may be entitled to severance and other benefits following the termination of their employment. These benefits are summarized below. The amounts of potential post-employment payments assume that the triggering event took place on December 31, 2006.

If Mr. Lipinski s employment is terminated either by Coffeyville Resources, LLC without cause and other than for disability or by Mr. Lipinski for good reason (as these terms are defined in Mr. Lipinski s employment agreement), then Mr. Lipinski is entitled to receive as severance (a) salary continuation for 36 months and (b) the continuation of medical benefits for thirty-six months at active-employee rates or until such time as Mr. Lipinski becomes eligible for medical benefits from a subsequent employer. The estimated total amounts of these payments are set forth in the table below. As a condition to receiving the salary continuation and continuation of medical benefits, Mr. Lipinski must (a) execute, deliver and not revoke a general release of claims and (b) abide by restrictive covenants as detailed below. If Mr. Lipinski s employment is terminated as a result of his disability, then in addition to any payments to be made to Mr. Lipinski under disability plan(s), Mr. Lipinski is entitled to supplemental disability payments equal to, in the aggregate, Mr. Lipinski s base salary as in effect immediately before his disability (the estimated total amount of this payment is set forth in the table below). Such supplemental disability payments will be made in installments for a period of 36 months from the date of disability. If Mr. Lipinski s employment is terminated at any time by reason of his death, then Mr. Lipinski s beneficiary (or his estate) will be paid the base salary Mr. Lipinski would have received had he remained employed through the remaining term of his contract. Notwithstanding the foregoing, Coffeyville

Resources, LLC may, at its option, purchase insurance to cover the obligations with respect to either Mr. Lipinski s supplemental disability payments or the payments due to Mr. Lipinski s beneficiary or estate by reason of his death. Mr. Lipinski will be required to cooperate in obtaining such insurance. If any payments or distributions due to Mr. Lipinski would be subject to the excise tax imposed under Section 4999 of the Internal Revenue Code of

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1986, as amended, then such payments or distributions will be cut back so that they will no longer be subject to the excise tax. Prior to the completion of this offering, Coffeyville Resources, LLC intends to amend Mr. Lipinski s agreement so that his payments and distributions will be cut back only if that reduction would be more beneficial to him on an after-tax basis than if there were no reduction.

The agreement requires Mr. Lipinski to abide by a perpetual restrictive covenant relating to non-disclosure. The agreement also includes covenants relating to non-solicitation and non-competition during Mr. Lipinski s employment and, following termination of employment, for as long as he is receiving severance or supplemental disability payments or one year if he is receiving none.

If the employment of Mr. Riemann, Mr. Rens, Mr. Haugen or Mr. Jernigan is terminated either by Coffeyville Resources, LLC without cause and other than for disability or by the executive officer for good reason (as such terms are defined in the respective employment agreements), then the executive officer is entitled to receive as severance (a) salary continuation for 12 months (18 months for Mr. Riemann) and (b) the continuation of medical benefits for 12 months (18 months for Mr. Riemann) at active-employee rates or until such time as the executive officer becomes eligible for medical benefits from a subsequent employer. The amount of these payments is set forth in the table below. As a condition to receiving the salary, the executives must (a) execute, deliver and not revoke a general release of claims and (b) abide by restrictive covenants as detailed below. The agreements provide that if any payments or distributions due to an executive officer would be subject to the excise tax imposed under Section 4999 of the Internal Revenue Code, as amended, then such payments or distributions will be cut back so that they will no longer be subject to the excise tax. Prior to the completion of this offering, Coffeyville Resources, LLC intends to amend these employment agreements so that each executive officer s payments and distributions will be cut back only if that reduction would be more beneficial to the executive officer on an after-tax basis than if there were no reduction.

The agreements require each of the executive officers to abide by a perpetual restrictive covenant relating to non-disclosure. The agreements also include covenants relating to non-solicitation and non-competition during their employment and, following termination of employment, for one year (for Mr. Riemann, the applicable period is during his employment and, following termination of employment, for as long as he is receiving severance, or one year if he is receiving none).

Below is a table setting forth the estimated aggregate amount of the payments discussed above assuming a December 31, 2006 termination date (and, where applicable, no offset due to eligibility to receive medical benefits from a subsequent employer). The table assumes that the executive officers termination was by Coffeyville Resources, LLC without cause or by the executive officers for good reason, and in the case of Mr. Lipinski also provides information assuming his termination was due to his disability.

Name	Total Severance Payments	Estimated Dollar Value of Medical Benefits
John J. Lipinski (severance if terminated without cause or resigns for good reason)	$ 1,950,000	$ 20,307
John J. Lipinski (supplemental disability payments if terminated due to disability)	$ 650,000	
Stanley A. Riemann	$ 525,000	$ 10,154
James T. Rens	$ 250,000	$ 9,713
Robert W. Haugen	$ 225,000	$ 9,713
Wyatt E. Jernigan	$ 225,000	$ 3,154

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Director Compensation

Name	Fees Earned or Paid in Cash	All Other Compensation	Total
Wesley Clark	$ 40,000	$ 257,352(1)	$ 297,352
Scott L. Lebovitz, George E. Matelich, Stanley de J. Osborne and Kenneth A. Pontarelli	$ 0	$ 0	$ 0

(1) Mr. Clark was awarded 244,038 phantom service points and 244,038 phantom performance points under the Coffeyville Resources, LLC Phantom Unit Plan (Plan I) in September 2005. Collectively, Mr. Clark s phantom points represent 2.44% of the total phantom points awarded. The value of the interest was $71,234 on the grant date. In accordance with SFAS 123(R), we apply a fair-value-based measurement method in accounting for share-based issuance of the phantom points. An independent third-party valuation is performed at the end of each reporting period using a binomial model based on company projections of undiscounted future cash flows. Assumptions used in the calculation of these amounts are included in footnote 5 to our audited financial statements for the year ended December 31, 2006. The phantom points are more fully described above under *Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II).*

Non-employee directors who do not work principally for entities affiliated with us were entitled to receive an annual retainer of $40,000 in 2006 and are entitled to receive an annual retainer of $60,000 in 2007. In addition, all directors are reimbursed for travel expenses and other out-of-pocket costs incurred in connection with their attendance at meetings. Effective January 1, 2007, Mark Tomkins joined our board of directors. Mr. Tomkins was elected as the chairman of the audit committee and in that role he receives an additional annual retainer of $15,000. Messrs. Lebovitz, Matelich, Osborne and Pontarelli received no compensation in respect of their service as directors in 2006.

In connection with this offering, we intend to grant 12,500 shares of non-vested restricted stock of CVR Energy to Mr. Tomkins and 5,000 shares of non-vested restricted stock of CVR Energy to Mr. Lippert. The restrictions on these shares will generally lapse in one-third annual increments beginning on the first anniversary of the date of grant. In addition to the annual retainer described above, we intend to make a grant to each of Mr. Tomkins and Mr. Lippert of an option to purchase 5,150 shares of CVR Energy with an exercise price equal to the initial public offering price. These options will generally vest in one-third annual increments beginning on the first anniversary of the date of grant.

Compensation Committee Interlocks and Insider Participation

Mr. Lipinski, our chief executive officer, served on the compensation committee of Coffeyville Acquisition LLC during 2005 and 2006. Mr. Lipinski is also a director and serves on the compensation committee of INTERCAT, Inc., a privately held company of which Regis B. Lippert, who serves as a director on our board of directors, is the chief executive officer. Otherwise, no interlocking relationship exists between our board of directors or compensation committee and the board of directors or compensation committee of any other company.

Employee Stock Grants

In connection with this offering, we plan to grant 50 shares of common stock in CVR Energy to each of our employees who does not currently have either phantom points or override units. This group, which currently consists of 542 employees, will receive 27,100 shares. In addition, we plan to award each of these employees a cash payment of $575. Because all of the named executive officers currently own phantom points and override units, none will be part of this program.

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PRINCIPAL STOCKHOLDERS

The following table presents information regarding beneficial ownership of our common stock by:

- each of our directors;
- each of our named executive officers;
- each stockholder known by us to beneficially hold five percent or more of our common stock; and
- all of our executive officers and directors as a group.

Beneficial ownership is determined under the rules of the SEC and generally includes voting or investment power with respect to securities. Unless indicated below, to our knowledge, the persons and entities named in the table have sole voting and sole investment power with respect to all shares beneficially owned, subject to community property laws where applicable. Shares of common stock subject to options that are currently exercisable or exercisable within 60 days of the date of this prospectus are deemed to be outstanding and to be beneficially owned by the person holding such options for the purpose of computing the percentage ownership of that person but are not treated as outstanding for the purpose of computing the percentage ownership of any other person. Except as otherwise indicated, the business address for each of our beneficial owners is c/o CVR Energy, Inc., 2277 Plaza Drive, Suite 500, Sugar Land, Texas 77479.

Prior to this offering, Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC owned 100% of our outstanding common stock. Following the closing of this offering, each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC will own 31,433,360 shares of our common stock, or approximately 37.8% of our outstanding common stock, and the Goldman Sachs Funds and the Kelso Funds, along with certain members of management, will beneficially own their interests in our common stock set forth below through their ownership of Coffeyville Acquisition LLC and/or Coffeyville Acquisition II LLC, as applicable. John J. Lipinski will own a portion of his shares in us directly and a portion indirectly through his interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Unless otherwise indicated, information in the table below for the Goldman Sachs Funds, the Kelso Funds and our officers and directors reflects the number of shares of our common stock that correspond to each named holder s economic interest in common units in Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, and does not reflect any interest in operating override units and value override units in Coffeyville Acquisition LLC and/or Coffeyville Acquisition II LLC, as applicable. Management will not have the right to vote or dispose of shares held by Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, and thus will not have beneficial ownership of such shares, but will receive net proceeds upon the sale of shares by such entities in an amount based on their interest in the common units and override units of such entities to the extent such entities distribute cash received to their members upon the sale of shares.

Name and Address	Shares Beneficially Owned Prior to this Offering		Shares Beneficially Owned After this Offering Assuming the Underwriters Option Is Not Exercised(1)		Shares Beneficially Owned After this Offering Assuming the Underwriters Option Is Exercised In Full (1)	
	Number	Percent	Number	Percent	Number	Percent
Coffeyville Acquisition LLC(2)(3)	31,433,360	49.8%	31,433,360	37.8%	31,433,360	36.5%
Coffeyville Acquisition II LLC(4)(5)	31,433,360	49.8%	31,433,360	37.8%	31,433,360	36.5%
The Goldman Sachs Group, Inc.(4)	31,125,918	49.3%	31,125,918	37.4%	31,125,918	36.1%
85 Broad Street						
New York, New York 10004						
Kelso Investment Associates VII, L.P.(2)	24,557,883	38.9%	24,557,883	29.5%	24,557,883	28.5%
KEP VI, LLC(2)	6,081,000	9.6%	6,081,000	7.3%	6,081,000	7.1%
320 Park Avenue, 24th Floor						
New York, New York 10022						
John J. Lipinski(6)	405,756	*	405,756	*	405,756	*
Stanley A. Riemann(7)	97,408	*	97,408	*	97,408	*
James T. Rens(7)	60,879	*	60,879	*	60,879	*
Edmund S. Gross(7)	7,305	*	7,305	*	7,305	*
Robert W. Haugen(7)	24,352	*	24,352	*	24,352	*
Wyatt E. Jernigan(7)	24,352	*	24,352	*	24,352	*
Kevan A. Vick(7)	60,880	*	60,880	*	60,880	*
Christopher G. Swanberg(7)	6,087	*	6,087	*	6,087	*
Wesley K. Clark(7)	60,880	*	60,880	*	60,880	*
Scott L. Lebovitz		*		*		*
Regis B. Lippert(8)		*	5,000	*	5,000	*
George E. Matelich(2)	30,638,883	48.5%	30,638,883	36.8%	30,638,883	35.6%
Stanley de J. Osborne		*		*		*
Kenneth A. Pontarelli(4)	31,125,918	49.3%	31,125,918	37.4%	31,125,918	36.1%
Mark E. Tomkins(9)		*	12,500	*	12,500	*
All directors and executive officers, as a group (15 persons)	62,530,200	99.0%	62,530,200	75.2%	62,530,200	72.6%

* Less than 1%

(1) The underwriters have an option to purchase up to an additional 3,000,000 shares from us in this offering.

(2) Coffeyville Acquisition LLC directly owns 31,433,360 shares of common stock. The number of shares indicated as owned by the Kelso Funds reflects the number of shares of common stock that corresponds to the number of common units held by the Kelso Funds in Coffeyville Acquisition LLC. With respect to the total number of shares of common stock deemed to be beneficially owned prior to this offering, the share amount includes

(1) 24,557,883 shares of common stock deemed to be beneficially owned by Kelso Investment Associates VII, L.P., a Delaware limited partnership, or KIA VII, and (2) 6,081,000 shares of common stock deemed to be beneficially owned by KEP VI, LLC, a Delaware limited liability company, or KEP VI. KIA VII and KEP VI, due to their common control, could be deemed to beneficially own each of the other s shares but each disclaims such beneficial ownership. Shares and percentages indicated represent the upper limit of the expected ownership of our equity securities by these persons and entities. Messrs. Nickell, Wall, Matelich, Goldberg, Wahrhaftig, Bynum, Berney, Loverro and Connors may be deemed to share beneficial ownership of shares of common stock owned of record, by virtue of their status as managing members of KEP VI and of Kelso GP VII, LLC, a Delaware limited liability company, the principal business of which is serving as the general partner of Kelso GP VII, L.P., a Delaware limited partnership, the principal business of which is serving as the general

partner of KIA VII. Each of Messrs. Nickell, Wall, Matelich, Goldberg, Wahrhaftig, Bynum, Berney, Loverro and Connors share investment and voting power with respect to the ownership interests owned by KIA VII and KEP VI but disclaim beneficial ownership of such interests.

(3) The board of directors of Coffeyville Acquisition LLC has the power to dispose of the securities of Coffeyville Acquisition LLC.

(4) Coffeyville Acquisition II LLC directly owns 31,433,360 shares of common stock. The number of shares indicated as owned by The Goldman Sachs Group, Inc. reflects the number of shares of common stock that corresponds to the number of common units held by the Goldman Sachs Funds in Coffeyville Acquisition II LLC. The Goldman Sachs Group, Inc., and certain affiliates, including Goldman, Sachs & Co., may be deemed to directly or indirectly own in the aggregate 31,125,918 shares of common stock which are deemed to be beneficially owned directly or indirectly by investment partnerships, which we refer to as the Goldman Sachs Funds, of which affiliates of The Goldman Sachs Group, Inc. and Goldman, Sachs & Co. are the general partner, managing limited partner or the managing partner. Goldman, Sachs & Co. is the investment manager for certain of the Goldman Sachs Funds. Goldman, Sachs & Co. is a direct and indirect, wholly owned subsidiary of The Goldman Sachs Group, Inc. The Goldman Sachs Group, Inc., Goldman, Sachs & Co. and the Goldman Sachs Funds share voting power and investment power with certain of their respective affiliates. Shares deemed to be beneficially owned by the Goldman Sachs Funds consist of: (1) 16,389,665 shares of common stock deemed to be beneficially owned by GS Capital Partners V Fund, L.P., (2) 8,466,218 shares of common stock deemed to be beneficially owned by GS Capital Partners V Offshore Fund, L.P., (3) 5,620,242 shares of common stock deemed to be beneficially owned by GS Capital Partners V Institutional, L.P., and (4) 649,793 shares of common stock deemed to be beneficially owned by GS Capital Partners V GmbH & Co. KG. Ken Pontarelli is a managing director of Goldman, Sachs & Co. Mr. Pontarelli, The Goldman Sachs Group, Inc. and Goldman, Sachs & Co. each disclaims beneficial ownership of the shares of common stock owned directly or indirectly by the Goldman Sachs Funds, except to the extent of their pecuniary interest therein, if any.

(5) The board of directors of Coffeyville Acquisition II LLC has the power to dispose of the securities of Coffeyville Acquisition II LLC.

(6) Of the 405,756 shares of common stock indicated above, 247,471 shares are owned directly by Mr. Lipinski and 158,285 shares represent shares Mr. Lipinski owns indirectly through his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Mr. Lipinski does not have the power to vote or dispose of shares that correspond to his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and thus does not have beneficial ownership of such shares.

(7) Reflects the number of shares of common stock that corresponds to such holder s interest in common units of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Such holder does not have the power to vote or dispose of such shares and thus does not have beneficial ownership of such shares.

(8) In connection with this offering, our board of directors has awarded 5,000 shares of non-vested restricted stock to Mr. Lippert. The restrictions on these shares will generally lapse in one-third annual increments beginning on the first anniversary of the date of grant. In addition, our board of directors has awarded Mr. Lippert options to purchase 5,150 shares of common stock with an exercise price equal to the initial public offering price. These options will generally vest in one-third annual increments beginning on the first anniversary of the date of grant.

(9) In connection with this offering, our board of directors has awarded 12,500 shares of non-vested restricted stock to Mark E. Tomkins. The restrictions on these shares will generally lapse in one-third annual increments beginning on the first anniversary of the date of grant. In addition, our board of directors has awarded

Mr. Tomkins options to purchase 5,150 shares of common stock with an exercise price equal to the initial public offering price. These options will generally vest in one-third annual increments beginning on the first anniversary of the date of grant.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

This section describes related party transactions between CVR Energy (and its predecessors) and its directors, executive officers and 5% stockholders. For a description of transactions between CVR Energy and the Partnership, whose managing general partner is owned by our controlling stockholders and senior management, see The Nitrogen Fertilizer Limited Partnership.

Transactions with the Goldman Sachs Funds and the Kelso Funds

Prior to this offering, GS Capital Partners V Fund, L.P. and related entities, or the Goldman Sachs Funds, and Kelso Investment Associates VII, L.P. and related entity, the Kelso Funds, were the majority owners of Coffeyville Acquisition LLC.

As part of the Transactions, Coffeyville Acquisition LLC will redeem all of its outstanding common units held by the Goldman Sachs Funds in exchange for the same number of common units in Coffeyville Acquisition II LLC, a newly formed limited liability company to which Coffeyville Acquisition LLC will transfer half of its interests in each of Coffeyville Refining & Marketing Holdings, Inc., Coffeyville Nitrogen Fertilizers, Inc. and CVR Energy. In addition, half of the common units and override units in Coffeyville Acquisition LLC held by each executive officer will be redeemed in exchange for an equal number of common units and override units in Coffeyville Acquisition II LLC. Following the consummation of this offering, the Kelso Funds will be the majority owner of Coffeyville Acquisition LLC and the Goldman Sachs Funds will be the majority owner of Coffeyville Acquisition II LLC.

Investments in Coffeyville Acquisition LLC

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, between Coffeyville Group Holdings, LLC and Coffeyville Acquisition LLC, Coffeyville Acquisition LLC acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. The Goldman Sachs Funds made capital contributions of $112,817,500 to Coffeyville Acquisition LLC and the Kelso Funds made capital contributions of $110,817,500 to Coffeyville Acquisition LLC in connection with the acquisition. The total proceeds received by Pegasus Partners II, L.P. and the other unit holders of Coffeyville Group Holdings, LLC, including then current management, in connection with the Subsequent Acquisition was $526,185,017, after repayment of Immediate Predecessor s credit facility.

Coffeyville Acquisition LLC paid companies related to the Goldman Sachs Funds and the Kelso Funds each equal amounts totaling $6.0 million for the transaction fees related to the Subsequent Acquisition, as well as an additional $0.7 million paid to the Goldman Sachs Funds for reimbursed expenses related to the Subsequent Acquisition.

On July 25, 2005, the following executive officers and directors made the following capital contributions to Coffeyville Acquisition LLC: John J. Lipinski, $650,000; Stanley A. Riemann, $400,000; James T. Rens, $250,000; Kevan A. Vick, $250,000; Robert W. Haugen, $100,000; Wyatt E. Jernigan, $100,000; Chris Swanberg, $25,000. On September 12, 2005, Edmund Gross made a $30,000 capital contribution to Coffeyville Acquisition LLC. On September 20, 2005, Wesley Clark made a $250,000 capital contribution to Coffeyville Acquisition LLC. All but two of the executive officers received common units, operating units and value units of Coffeyville Acquisition LLC and the director received common units of Coffeyville Acquisition LLC.

On September 14, 2005, the Goldman Sachs Funds and the Kelso Funds each invested an additional $5.0 million in Coffeyville Acquisition LLC. On May 23, 2006, the Goldman Sachs Funds and the Kelso Funds each invested an additional $10.0 million in Coffeyville Acquisition LLC. In each case they received additional common units of Coffeyville Acquisition LLC.

On December 28, 2006, Coffeyville Acquisition LLC granted John J. Lipinski 217,458 override units, of which 72,492 were operating units and 144,966 were value units. Mr. Lipinski subsequently transferred all of his override units to trusts for the benefit of members of his family.

On December 28, 2006, the directors of Coffeyville Acquisition LLC approved a cash dividend of $244,710,000 to companies related to the Goldman Sachs Funds and the Kelso Funds and $3,360,393 to certain members of our management, including John J. Lipinski ($914,844), Stanley A.

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Riemann ($548,070), James T. Rens ($321,180), Kevan A. Vick ($321,180), Robert W. Haugen ($164,680) and Wyatt E. Jernigan ($164,680), as well as Wesley Clark ($241,205).

In connection with this offering, the directors of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, respectively, will approve a special dividend of $10.6 million to their members, including $5,227,584 to the Goldman Sachs Funds, $5,145,787 to the Kelso Funds and $185,067 to certain members of our management and Wesley Clark. The common unit holders receiving this special dividend will contribute $10.6 million collectively to Coffeyville Acquisition III LLC, which will use such amounts to acquire the managing general partner.

J. Aron & Company

Coffeyville Acquisition LLC entered into commodity derivative contracts in the form of three swap agreements for the period from July 1, 2005 through June 30, 2010 with J. Aron, a subsidiary of The Goldman Sachs Group, Inc. The swap agreements were originally entered into by Coffeyville Acquisition LLC on June 16, 2005 in conjunction with the acquisition of Immediate Predecessor and were required under the terms of our long-term debt agreements. The swap agreements were executed at the prevailing market rate at the time of execution and management believes the swap agreements provide an economic hedge on future transactions. These agreements were assigned to Coffeyville Resources, LLC on June 24, 2005. With crude oil capacity expected to reach 115,000 bpd by the end of 2007, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of the Credit Facility and upon meeting specific requirements related to an initial public offering, our leverage ratio and our credit ratings, and assuming our other credit facilities are terminated or amended to allow such actions, we may reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010. The Cash Flow Swap has resulted in unrealized losses of approximately $235.9 million at December 31, 2005, unrealized gains of approximately $126.8 million for the year ended December 31, 2006 and unrealized losses of approximately $188.5 million for the six months ended June 30, 2007. See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Derivative Instruments and Fair Value of Financial Instruments and Description of Our Indebtedness and the Cash Flow Swap Cash Flow Swap.

Effective December 30, 2005, Coffeyville Acquisition LLC entered into a crude oil supply agreement with J. Aron. Other than locally produced crude we gather ourselves, we purchase crude oil from third parties using this credit intermediation agreement. The terms of this agreement provide that we will obtain all of the crude oil for our refinery, other than the crude we obtain through our own gathering system, through J. Aron. Once we identify cargos of crude oil and pricing terms that meet our requirements, we notify J. Aron and J. Aron then provides credit, transportation and other logistical services to us for a fee. This agreement significantly reduces the investment that we are required to maintain in petroleum inventories relative to our competitors and reduces the time we are exposed to market fluctuations before the inventory is priced to a customer. The current credit intermediation agreement with J. Aron expires on December 31, 2007. At that time we may renegotiate the agreement with J. Aron, seek a similar arrangement with another party, or choose to obtain our crude supply directly without the use of an intermediary.

Coffeyville Acquisition LLC also entered into certain crude oil, heating oil, and gasoline option agreements with J. Aron as of May 16, 2005. These agreements expired unexercised on June 16, 2005 and resulted in an expense of $25,000,000 reported in the accompanying consolidated statements of operations as gain (loss) on derivatives for the 233 days ended December 31, 2005.

As a result of the refinery turnaround in early 2007, we needed to delay the processing of quantities of crude oil that we purchased from various small independent producers. In order to facilitate this anticipated delay, we entered into a purchase, storage and sale agreement for gathered crude oil, dated March 20, 2007, with J. Aron. Pursuant to the terms of the agreement, J. Aron agreed

to purchase gathered crude oil from us, store the gathered crude oil and sell us the gathered crude oil on a forward basis.

As a result of the flood and the temporary cessation of our Company s operations on June 30, 2007, Coffeyville Resources, LLC was required to enter into several deferral agreements with J. Aron with respect to the Cash Flow Swap. These deferral agreements deferred to January 31, 2008 the payment of approximately $123.7 million (plus accrued interest) which we owed to J. Aron. Assuming our initial public offering occurs prior to January 31, 2008, J. Aron agreed to further defer these payments to August 31, 2008 but we will be required to use 37.5% of our consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferred amounts.

Consulting and Advisory Agreements

Under the terms of separate consulting and advisory agreements, dated June 24, 2005, between Coffeyville Acquisition LLC and each of Goldman, Sachs & Co. and Kelso & Company, L.P., Coffeyville Acquisition LLC was required to pay an advisory fee of $1,000,000 per year, payable quarterly in advance, to each of Goldman Sachs and Kelso for consulting and advisory services provided by Goldman Sachs and Kelso. The advisory agreements provide that Coffeyville Acquisition LLC will indemnify Goldman Sachs and Kelso and their respective affiliates, designees, officers, directors, partners, employees, agents and control persons (as such term is used in the Securities Act and the rules and regulations thereunder), to the extent lawful, against claims, losses and expenses as incurred in connection with the services rendered to Coffeyville Acquisition LLC under the consulting and advisory agreements or arising out of any such person being a controlling person of Coffeyville Acquisition LLC. The agreements also provide that Coffeyville Acquisition LLC will reimburse expenses incurred by Goldman Sachs and Kelso in connection with their investment in Coffeyville Acquisition and with respect to services provided to Coffeyville Acquisition LLC pursuant to the consulting and advisory agreements. The consulting and advisory agreements also provide for the payment of certain fees, as may be determined by mutual agreement, payable by Coffeyville Acquisition LLC to Goldman Sachs and Kelso in connection with transaction services and for the reimbursement of expenses incurred in connection with such services. Payments relating to the consulting and advisory agreements include $1,310,416, $2,315,937 and $1,038,873 which was expensed in selling, general, and administrative expenses for the 233 days ended December 31, 2005, the year ended December 31, 2006 and the six months ended June 30, 2007, respectively. In addition, $1,046,575, $0 and $0 were included in other current liabilities and approximately $78,671, $0 and $500,000 were included in accounts payable at December 31, 2005, December 31, 2006 and June 30, 2007, respectively.

Pursuant to the terms of these consulting and advisory agreements, these agreements will automatically terminate upon consummation of this offering and each of Goldman, Sachs & Co. and Kelso & Company, L.P. will receive a one-time fee of $5 million by reason of such termination in conjunction with this offering. Pursuant to the terms of these consulting and advisory agreements, Coffeyville Acquisition LLC s obligations under such agreements, including, without limitation, obligations with respect to the indemnification of Goldman, Sachs & Co., Kelso & Company, L.P. and their respective affiliates and reimbursement of expenses, will survive such termination.

Credit Facilities

Goldman Sachs Credit Partners L.P., an affiliate of Goldman, Sachs & Co., or Goldman Sachs, is one of the lenders under the Credit Facility. Goldman Sachs Credit Partners is also a joint lead arranger and bookrunner under the Credit Facility. In addition, Goldman Sachs Credit Partners L.P. is the sole arranger and sole bookrunner of the $25 million secured facility, the $25 million unsecured facility, and the $75 million unsecured facility. Goldman Sachs Credit Partners was also a lender, sole lead arranger, sole bookrunner and syndication agent under our first lien credit agreement and a lender and joint lead arranger, joint bookrunner and syndication agent under our second lien credit agreement. The first lien credit agreement and second lien credit agreement were entered into in connection with the financing of the Subsequent Acquisition and, at that time, we paid this Goldman

Sachs affiliate a $22.1 million fee included in deferred financing costs. In conjunction with the financing that occurred on December 28, 2006, we paid approximately $8.1 million to a Goldman Sachs affiliate. Additionally, in conjunction with entering into the $25 million secured facility, the $25 million unsecured facility, and the $75 million unsecured facility on August 23, 2007, we paid approximately $1.3 million in fees and associated expense reimbursement to a Goldman Sachs affiliate. For the 233 days ended December 31, 2005, Successor made interest payments to this Goldman Sachs affiliate of $1.8 million recorded in interest expense and paid letter of credit fees of approximately $155,000 which were recorded in selling, general, and administrative expenses. See Description of Our Indebtedness and the Cash Flow Swap.

Guarantees

One of the Goldman Sachs Funds and one of the Kelso Funds have each guaranteed 50% of (1) our obligations under the $25 million secured facility, the $25 million unsecured facility and the $75 million unsecured facility and (2) our payment obligations under the Cash Flow Swap in the amount of $123.7 million, plus accrued interest. In addition, Coffeyville Acquisition LLC currently guarantees and, following the closing of this offering, Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC will each guarantee 50% of the obligations under the $75 million unsecured facility.

Transactions with Senior Management

On June 30, 2005, Coffeyville Acquisition LLC loaned $500,000 to John J. Lipinski, CEO of Successor. This loan accrued interest at the rate of 7% per year. The loan was made in conjunction with Mr. Lipinski s purchase of 50,000 common units of Coffeyville Acquisition LLC. Mr. Lipinski repaid $150,000 of principal and paid $17,643.84 in interest on January 13, 2006. The unpaid loan balance of $350,000, together with accrued and unpaid interest of $17,989, was forgiven in full in September 2006.

On December 28, 2006, Coffeyville Acquisition LLC granted John J. Lipinski 217,458 override units, of which 72,492 were operating units and 144,966 were value units. Mr. Lipinski subsequently transferred all of his override units to trusts for the benefit of members of his family.

On December 28, 2006, the directors of Coffeyville Nitrogen Fertilizer, Inc. approved the issuance of shares of common stock of Coffeyville Nitrogen Fertilizer, par value $0.01 per share, to John J. Lipinski in exchange for $10.00 pursuant to a Subscription Agreement. Mr. Lipinski also entered into a Stockholders Agreement with Coffeyville Nitrogen Fertilizer and Coffeyville Acquisition LLC at the same time he entered into the Subscription Agreement. Pursuant to the Stockholders Agreement, Mr. Lipinski may not transfer any shares of common stock in Coffeyville Nitrogen Fertilizer except in certain specified circumstances. Coffeyville Nitrogen Fertilizer also has certain buyback and repurchase rights for all of Mr. Lipinski s shares if Mr. Lipinski is terminated. Coffeyville Acquisition LLC has the right to exchange all shares of common stock in Coffeyville Nitrogen Fertilizer held by Mr. Lipinski for such number of common units of Coffeyville Acquisition LLC or equity interests of a wholly-owned subsidiary of Coffeyville Acquisition LLC, in each case having a fair market value equal to the fair market value of the common stock in Coffeyville Nitrogen Fertilizer held by Mr. Lipinski.

On December 28, 2006, the directors of Coffeyville Refining & Marketing, Inc. approved the issuance of shares of common stock of Coffeyville Refining & Marketing, par value $0.01 per share, to John J. Lipinski in exchange for $10.00 pursuant to a Subscription Agreement. Mr. Lipinski entered into a stockholders agreement with Coffeyville Refining & Marketing similar to the agreement he entered into with Coffeyville Nitrogen Fertilizers.

In connection with the formation of Coffeyville Refining & Marketing Holdings, Inc., Mr. Lipinski s shares of common stock in Coffeyville Refining & Marketing, Inc. were exchanged for an equivalent number of shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. Mr. Lipinski also entered into a Stockholders Agreement with Coffeyville Refining & Marketing Holdings, Inc. and Coffeyville Acquisition LLC at the time of the exchange. Pursuant to the Stockholders Agreement, Mr. Lipinski may not transfer any shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. except in certain specified circumstances. Coffeyville Refining & Marketing Holdings, Inc. also has certain buyback and repurchase rights for all of Mr. Lipinski s shares if Mr. Lipinski is

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terminated. Coffeyville Acquisition LLC has the right to exchange all shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. held by Mr. Lipinski for such number of common units of Coffeyville Acquisition LLC or equity interests of a wholly-owned subsidiary of Coffeyville Acquisition LLC, in each case having a fair market value equal to the fair market value of the common stock in Coffeyville Refining & Marketing Holdings, Inc. held by Mr. Lipinski.

In connection with the Transactions, we intend to enter into a Subscription Agreement prior to the completion of this offering pursuant to which Mr. Lipinski will exchange his shares of common stock of Coffeyville Nitrogen Fertilizer, Inc. and Coffeyville Refining & Marketing Holdings, Inc. for shares of our common stock. Under this agreement based upon the expected fair market value of the stock to be exchanged, we expect to issue 247,471 shares of common stock to Mr. Lipinski.

Mr. John J. Lipinski owns approximately 0.3128% of Coffeyville Refining and Marketing Holdings, Inc. and approximately 0.6401% of Coffeyville Nitrogen Fertilizer, Inc. These two companies currently own all of the interests which will be owned by CVR Energy upon the completion of this offering. The allocation of value as of September 30, 2007 between Coffeyville Refining and Marketing Holdings, Inc. and Coffeyville Nitrogen Fertilizer, Inc. is 75.7717% and 24.2283%, respectively. The allocation of value is based on their respective ownership interest in their subsidiaries taking into effect liabilities and receivables existing between the two companies. The number of shares issued to Mr. Lipinski was determined by grossing up the shares after our stock split by the weighted average percentage ownership of Mr. Lipinski in the two entities and multiplying the result by Mr. Lipinski s weighted average percentage ownership. The table below illustrates the calculations of the shares issued to Mr. Lipinski.

	Relative ownership in all interests contributed to CVR Energy	
A	Coffeyville Refining and Marketing Holdings, Inc.	75.7717%
B	Coffeyville Nitrogen Fertilizer, Inc.	24.2283%
	Mr. Lipinski s Interests in the subsidiaries	
D	Coffeyville Refining and Marketing Holdings, Inc.	0.3128%
E	Coffeyville Nitrogen Fertilizer, Inc.	0.6401%
	Weighted average ownership in all assets	
F: = A x D	Coffeyville Refining and Marketing Holdings, Inc.	0.23701%
G: = B x E	Coffeyville Nitrogen Fertilizer, Inc.	0.15509%
H: = F + G	Mr. Lipinski s weighted average ownership interest	0.3921%
I	Original shares	100.00
J	Stock split	628,667.20
K: = I x J	Shares to members of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC	62,866,720.00
L: = H x (K/(1-H))	Mr. Lipinski s shares	247,471.00
M: = K + L	Total shares before director shares, this offering and employee shares	63,114,191
N: = L/M	Mr. Lipinski s percentage of pre-offering shares	0.3921%

All decisions concerning Mr. Lipinski s compensation have been approved by the compensation committee of Coffeyville Acquisition LLC without Mr. Lipinski s participation.

In April 2007, we paid Stanley A. Riemann, our Chief Operating Officer, approximately $220,000 as a relocation incentive in connection with our request for him to relocate from Missouri to Texas.

Coffeyville Acquisition LLC Operating Agreement

Prior to the consummation of this offering, the Goldman Sachs Funds, the Kelso Funds, and John J. Lipinski, Stanley A. Riemann, James T. Rens, Edmund Gross, Robert W. Haugen, Wyatt E. Jernigan, Kevan A. Vick, Christopher Swanberg, Wesley Clark, Magnetite Asset Investors III L.L.C.

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and other members of our management were members of Coffeyville Acquisition LLC, which owned all of our capital stock.

In connection with this offering, Coffeyville Acquisition LLC will redeem all of its outstanding common units held by the Goldman Sachs Funds in exchange for the same number of common units in Coffeyville Acquisition II LLC, a newly formed limited liability company to which Coffeyville Acquisition LLC will transfer half of its assets. As a result, CVR Energy will be owned equally by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. In addition, half of the common units and half of the profits interests in Coffeyville Acquisition LLC held by executive officers and a director will be redeemed in exchange for an equal number and type of limited liability interests in Coffeyville Acquisition II LLC. Following the consummation of this offering, the Kelso Funds will own substantially all of the common units of Coffeyville Acquisition LLC, the Goldman Sachs Funds will own substantially all of the common units of Coffeyville Acquisition II LLC and executive officers and a director will own an equal number and type of interests in both Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC.

The existing LLC Agreement of Coffeyville Acquisition LLC will be amended and restated to reflect this revised ownership structure. Among other things, the amended and restated LLC Agreement will contain provisions outlining the interests of senior management in Coffeyville Acquisition LLC. See Management Employment Agreements and Other Arrangements Executives Interests in Coffeyville Acquisition LLC. The operating agreement for Coffeyville Acquisition II LLC will be substantially the same as the amended and restated LLC Agreement of Coffeyville Acquisition LLC.

Stockholders Agreement

In connection with the Transactions, we intend to enter into a Stockholders Agreement with Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC prior to the completion of this offering. Pursuant to this agreement, for so long as Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC collectively beneficially own in the aggregate an amount of our common stock that represents at least 40% of our outstanding common stock, Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC each have the right to designate two directors to our board of directors so long as that party holds an amount of our common stock that represent 20% or more of our outstanding common stock and one director to our board of directors so long as that party holds an amount of our common stock that represent less than 20% but more than 5% of our outstanding common stock. If Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC cease to collectively beneficially own in the aggregate an amount of our common stock that represents at least 40% of our outstanding common stock, the foregoing rights become a nomination right and the parties to the Stockholders Agreement are not obligated to vote for each other s nominee. In addition, the Stockholders Agreement contains certain tag-along rights with respect to certain transfers (other than underwritten offerings to the public) of shares of common stock by the parties to the Stockholders Agreement. For so long as Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC beneficially own in the aggregate at least 40% of our common stock, (i) each such stockholder that has the right to designate at least two directors will have the right to have at least one of its designated directors on any committee (other than the audit committee and conflicts committee), to the extent permitted by SEC or NYSE rules, (ii) directors designated by the stockholders will be a majority of each such committee (at least 50% in the case of the compensation committee and the nominating committee), and (iii) the chairman of each such committee will be a director designated by such stockholder.

Registration Rights Agreements

In connection with the Transactions, we intend to enter into a registration rights agreement prior to the completion of this offering with Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC pursuant to which we may be required to register the sale of our shares held by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and permitted transferees. Under the registration rights

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agreement, the Goldman Sachs Funds and the Kelso Funds will each have the right to request that we register the sale of shares held by Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, on their behalf on three occasions including requiring us to make available shelf registration statements permitting sales of shares into the market from time to time over an extended period. In addition, the Goldman Sachs Funds and the Kelso Funds will have the ability to exercise certain piggyback registration rights with respect to their own securities if we elect to register any of our equity securities. The registration rights agreement will also include provisions dealing with holdback agreements, indemnification and contribution, and allocation of expenses. Immediately after this offering, all of our shares held by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC will be entitled to these registration rights.

In connection with the Transactions, we intend to enter into a registration rights agreement prior to the completion of this offering with John J. Lipinski. Under the registration rights agreement, Mr. Lipinski will have the ability to exercise certain piggyback registration rights with respect to his own securities if any of our equity securities are offered to the public pursuant to a registration statement. The registration rights agreement will also include provisions dealing with holdback agreements, indemnification and contribution, and allocation of expenses. Immediately after this offering, all of the shares in our company held directly by John J. Lipinski will be entitled to these registration rights.

Transactions with Pegasus Partners II, L.P.

Pegasus Partners II, L.P., or Pegasus, was a majority owner of Coffeyville Group Holdings, LLC (Immediate Predecessor) during the period March 3, 2004 through June 24, 2005. On March 3, 2004, Coffeyville Group Holdings, LLC, through its wholly owned subsidiary, Coffeyville Resources, LLC, acquired the assets of the former Farmland petroleum division and one facility within Farmland s nitrogen fertilizer manufacturing and marketing division through a bankruptcy court auction process for approximately $107 million and the assumption of approximately $23 million of liabilities.

On March 3, 2004, Coffeyville Group Holdings, LLC entered into a management services agreement with Pegasus Capital Advisors, L.P., pursuant to which Pegasus Capital Advisors, L.P. provided Coffeyville Group Holdings, LLC with managerial and advisory services. In consideration for these services, Coffeyville Group Holdings, LLC agreed to pay Pegasus Capital Advisors, L.P. an annual fee of up to $1.0 million plus reimbursement for any out-of-pocket expenses. During the year ended December 31, 2004, Immediate Predecessor paid an aggregate of approximately $545,000 to Pegasus Capital Advisors, L.P. in fees under this agreement. $1,000,000 was expensed to selling, general, and administrative expenses for the 174 days ended June 23, 2005. In addition, Immediate Predecessor paid approximately $455,000 in legal fees on behalf of Pegasus Capital Advisors, L.P. in lieu of the remaining amount owed under the management fee. This management services agreement terminated at the time of the Subsequent Acquisition in June 2005.

Coffeyville Group Holdings, LLC paid Pegasus Capital Advisors, L.P. a $4.0 million transaction fee upon closing of the acquisition on March 3, 2004. The transaction fee related to a $2.5 million merger and acquisition fee and $1.5 million in deferred financing costs. In addition, in conjunction with the refinancing of our senior secured credit facility on May 10, 2004, Coffeyville Group Holdings, LLC paid an additional $1.25 million fee to Pegasus Capital Advisors, L.P. as a deferred financing cost.

On March 3, 2004, Coffeyville Group Holdings, LLC entered into Executive Purchase and Vesting Agreements with the then executive officers listed below providing for the sale by Immediate Predecessor to them of the number of our common units to the right of each executive officer s name at a purchase price of approximately $0.0056 per unit. Pursuant to the terms of these agreements, as amended, each executive officer s common units were to vest at a rate of 16.66% every six months with the first 16.66% vesting on November 10, 2004. In connection with their purchase of the common units pursuant to the Executive Purchase and Vesting Agreements, each of the executive officers at that time issued promissory notes in the amounts indicated below. These notes were paid in full on May 10, 2004.

Executive Officer	Number of Common Units	Amount of Promissory Note
Philip L. Rinaldi	3,717,647	$ 21,000
Abraham H. Kaplan	2,230,589	$ 12,600
George W. Dorsey	2,230,589	$ 12,600
Stanley A. Riemann	1,301,176	$ 7,350
James T. Rens	371,764	$ 2,100
Keith D. Osborn	650,588	$ 3,675
Kevan A. Vick	650,588	$ 3,675

On May 10, 2004, Mr. Rinaldi entered into another Executive Purchase and Vesting Agreement under the same terms as described above providing for the purchase of an additional 500,000 common units of Coffeyville Group Holdings, LLC for an aggregate purchase price of $2,850.

On May 10, 2004, Coffeyville Group Holdings, LLC refinanced its existing long-term debt with a $150 million term loan and used the proceeds of the borrowings to repay the outstanding borrowings under Coffeyville Group Holdings, LLC s previous credit facility. The borrowings were also used to distribute a $99,987,509 dividend, which included a preference payment of $63,200,000 plus a yield of $1,802,956 to the preferred unit holders and a $63,000 payment to the common unit holders for undistributed capital per the LLC agreement. The remaining $34,921,553 was distributed to the preferred and common unit holders pro rata according to their ownership percentages, as determined by the aggregate of the common and preferred units.

On October 8, 2004, Coffeyville Group Holdings, LLC entered into a joint venture with The Leiber Group, Inc., a company whose majority stockholder was Pegasus Partners II, L.P., the principal stockholder of Immediate Predecessor. In connection with the joint venture, Coffeyville Group Holdings, LLC contributed approximately 68.7% of its membership interests in Coffeyville Resources, LLC to CL JV Holdings, LLC, a Delaware limited liability company, or CL JV Holdings, and The Leiber Group, Inc. contributed the Judith Leiber business to CL JV Holdings. At the time of the Subsequent Acquisition, in June 2005, the joint venture was effectively terminated.

On January 13, 2005, Immediate Predecessor s board of directors authorized the following bonus payments to the following then executive officers, at that time, in recognition of the importance of retaining their services:

Executive Officer	Bonus Amount
Philip L. Rinaldi	$ 1,000,000
Abraham H. Kaplan	$ 600,000
George W. Dorsey	$ 300,000
Stanley A. Riemann	$ 700,000
James T. Rens	$ 150,000
Keith D. Osborn	$ 150,000
Kevan A. Vick	$ 150,000
Edmund S. Gross	$ 200,000

During 2004 and 2005, Immediate Predecessor shared office space with Pegasus in New York, New York for which we paid Pegasus $10,000 per month.

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On June 23, 2005, immediately prior to the Subsequent Acquisition, Coffeyville Group Holdings, LLC used available cash balances to distribute a $52,211,493 dividend to its preferred and common unit holders pro rata according to their ownership percentages, as determined by the aggregate of the common and preferred units.

Other Transactions

We paid INTERCAT, Inc. $525,507 during 2006 for chemical additives. Mr. Regis B. Lippert, a director of our company, is the principal shareholder and chief executive officer of INTERCAT, Inc. Mr. John J. Lipinski, the chief executive officer and president of our company and a member of our board of directors, is a director and member of the compensation committee of INTERCAT, Inc.

Related Party Transaction Policy

Prior to the completion of this offering, our board of directors will adopt a Related Party Transaction Policy, which is designed to monitor and ensure the proper review, approval, ratification and disclosure of related party transactions involving us. This policy applies to any transaction, arrangement or relationship (or any series of similar transactions, arrangements or relationships) in which we were, are or will be a participant and the amount involved exceeds $100,000, and in which any related party had, has or will have a direct or indirect material interest. The audit committee of our board of directors must review, approve and ratify a related party transaction if such transaction is consistent with the Related Party Transaction Policy and is on terms, taken as a whole, which the audit committee believes are no less favorable to us than could be obtained in an arms-length transaction with an unrelated third party, unless the audit committee otherwise determines that the transaction is not in our best interests. Any related party transaction or modification of such transaction which our board of directors has approved or ratified by the affirmative vote of a majority of directors, who do not have a direct or indirect material interest in such transaction, does not need to be approved or ratified by our audit committee. In addition, related party transactions involving compensation will be approved by our compensation committee in lieu of our audit committee.

Conflicts of Interests Policy for Transactions between the Partnership and Us

Prior to the completion of this offering, our board of directors will adopt a Conflicts of Interests Policy, which is designed to monitor and ensure the proper review, approval, ratification and disclosure of transactions between the Partnership and us. The policy applies to any transaction, arrangement or relationship (or any series of similar transactions, arrangements or relationships) between us or any of our subsidiaries, on the one hand, and the Partnership, its managing general partner and any subsidiary of the Partnership, on the other hand. According to the policy, all such transactions must be fair and reasonable to us. If such transaction is expected to involve a value, over the life of such transaction, of less than $1 million, no special procedures will be required. If such transaction is expected to involve a value of more than $1 million but less than $5 million, it is deemed to be fair and reasonable to us if (i) such transaction is approved by the conflicts committee of our board of directors, (ii) the terms of such transaction are no less favorable to us than those generally being provided to or available from unrelated third parties or (iii) such transaction, taking into account the totality of any other such transaction being entered into at that time between the parties involved (including other transaction that may be particularly favorable or advantageous to us), is equitable to the Company. If such transaction is expected to involve a value, over the life of such transaction, of $5 million or more, it is deemed to be fair and reasonable to us if it has been approved by the conflicts committee of our board of directors.

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THE NITROGEN FERTILIZER LIMITED PARTNERSHIP

Background

Prior to the consummation of this offering, we intend to create a new limited partnership, CVR Partners, LP, or the Partnership, and to transfer our nitrogen fertilizer business to the Partnership. The Partnership will have two general partners: a managing general partner, CVR GP, LLC, which we refer to as Fertilizer GP, which we intend to sell to an entity owned by our controlling stockholders and senior management at fair market value prior to the consummation of this offering, and a second general partner, CVR Special GP, LLC, which is one of our wholly-owned subsidiaries. Another wholly-owned subsidiary of ours, Coffeyville Resources, LLC, will be a limited partner of the Partnership. Following the consummation of this offering, Coffeyville Acquisition III LLC, the sole parent of the managing general partner of the Partnership, will be owned by the Goldman Sachs Funds, the Kelso Funds, our executive officers, Mr. Wesley Clark, Magnetite Asset Investors III L.L.C. and other members of our management.

We have considered various strategic alternatives with respect to the nitrogen fertilizer business, including an initial public or private offering of limited partner interests of the Partnership. We have observed that entities structured as master limited partnerships, or MLPs, have over recent history demonstrated significantly greater relative market valuation levels compared to corporations in the refining and marketing, or R&M, sector when measured as a ratio of enterprise value, or EV, to EBITDA. For example, at calendar year-ends 2004, 2005 and 2006, a broad sampling of publicly traded MLPs has traded at average EV/Last Twelve Months, or LTM, EBITDA multiples of 13.8x, 13.1x and 12.9x which were 9.5x, 8.6x and 8.4x, respectively, higher than those multiples observed for publicly-traded corporations in the R&M sector. As of August 23, 2007, the average EV/LTM multiple for the same MLP entities was 15.6x, or 10.4x higher than the average for the publicly traded R&M corporations. We believe one of the reasons for the higher valuations is the treatment of these entities as partnerships for federal income tax purposes. Notwithstanding the foregoing, there is no assurance that the Partnership will seek to consummate a public or private offering of its limited partner interests and, if it does, there is no assurance that it would be able to realize valuations historically observed in the MLP sector. Any decision to pursue a public or private offering would be in the sole discretion of the managing general partner of the Partnership (subject to our joint management rights if in an amount over $200 million) and would be subject to, among other things, market conditions and negotiation of terms acceptable to the Partnership s managing general partner.

Prior to the consummation of this offering, CVR GP, LLC, as the managing general partner, Coffeyville Resources, LLC, as the limited partner, and CVR Special GP, LLC, as a general partner, will enter into a limited partnership agreement which will set forth the various rights and responsibilities of the partners in the Partnership and which is filed as an exhibit to the registration statement of which this prospectus is a part. In addition, we will enter into a number of intercompany agreements with the Partnership and the managing general partner which will regulate certain business relations among us, the Partnership and the managing general partner following this offering. In addition to regulating the ongoing business relations among us, the Partnership and the managing general partner, the partnership agreement and the other intercompany agreements will provide for:

- the formation and capitalization of the partnership, as described in Formation Transactions;
- a right for the managing general partner to cause the Partnership to pursue an initial public or initial private offering of its limited partner interests; and
- a restructuring of our interest in the Partnership, including a potential sale of a portion of our interest, in connection with any initial public or initial private offering by the Partnership, as described in Initial Offering Transactions.

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Formation Transactions

In connection with the formation of the Partnership, the Partnership will enter into a contribution, conveyance and assumption agreement, or the contribution agreement, with Fertilizer GP, CVR Special GP, LLC (our subsidiary that will hold our general partner interest in the Partnership), and Coffeyville Resources, LLC (our subsidiary that will hold our limited partner interest in the Partnership).

Pursuant to the contribution agreement, our subsidiary that owns the fertilizer business will distribute all of its receivables to Coffeyville Resources, LLC, after which Coffeyville Resources, LLC will transfer our subsidiary that owns the fertilizer business to the Partnership in exchange for (1) the issuance to CVR Special GP, LLC of 30,303,000 special GP units, representing a 99.9% general partner interest in the Partnership, (2) the issuance to Coffeyville Resources, LLC of 30,333 special LP units, representing a 0.1% limited partner interest in the Partnership, (3) the issuance to Fertilizer GP of the managing general partner interest in the Partnership and (4) the agreement by the Partnership, contingent upon the Partnership consummating an initial public or private offering, to reimburse us for capital expenditures we incurred during the two year period prior to the sale of the managing general partner to Coffeyville Acquisition III LLC, as described below, in connection with the operations of the fertilizer plant, currently estimated to be approximately $18 million. The Partnership will assume all liabilities arising out of or related to the ownership of the fertilizer business to the extent arising or accruing on and after the date of transfer. Following the transfer and issuance, the Partnership initially will be our wholly-owned subsidiary (prior to the sale of the managing general partner). Because we are contributing a wholly-owned subsidiary, which owns the fertilizer business, to another wholly-owned subsidiary, the Partnership, in exchange for all of the interests in the Partnership, we have not determined the fair market value of the assets and operations being transferred to the Partnership.

In connection with this offering, following formation of the Partnership pursuant to the contribution agreement, the following entities and individuals will contribute the following amounts in cash to Coffeyville Acquisition III LLC, a newly formed entity owned by our controlling stockholders and executive officers. Coffeyville Acquisition III LLC will use these contributions to purchase the managing general partner from us:

Contributing Parties		**Amount Contributed**
The Goldman Sachs Funds	$	5,227,584
The Kelso Funds		5,145,787
John J. Lipinski		68,146
Stanley A. Riemann		16,359
James T. Rens		10,225
Edmund S. Gross		1,227
Robert W. Haugen		4,090
Wyatt E. Jernigan		4,090
Kevan A. Vick		10,225
Christopher G. Swanberg		1,022
Wesley Clark		10,225
Others		101,020
Total Contribution:	$	10,600,000

Coffeyville Acquisition III will purchase the managing general partner from us for $10.6 million, which our board of directors has determined, after consultation with management, represents the fair market value of the managing general partner interest. The valuation of the managing general partner interest was based on a discounted cash flow analysis, using a discount rate commensurate with the risk profile of the managing general partner interest. The key assumptions underlying the analysis

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were commodity price projections, which were used to estimate the Partnership s raw material costs and output revenues. Other business expenses of the Partnership were estimated based on management s projections. The Partnership s cash distributions were assumed to be flat at expected forward fertilizer prices, with cash reserves developed in periods of high prices and cash reserves reduced in periods of lower prices. The Partnership s projected cash distributions to the managing general partner under the terms of the Partnership s partnership agreement used for the valuation were modeled based on the structure of the Partnership, the managing general partner s incentive distribution rights and management s expectations of the Partnership s operations, including production volumes and operating costs, which were developed by management based on historical experience. As commodity price curve projections were key assumptions in the discounted cash flow analysis, alternative price curve projections were considered in order to test the reasonableness of these assumptions, which gave management an added level of assurance as to such reasonableness. Price projections were based on information received from Blue Johnson and Associates, a leading fertilizer industry consultant in the United States which we routinely use for fertilizer market analysis. There can be no assurance that the value of the managing general partner will not differ in the future from the amount initially paid for it.

Description of Partnership Interests Initially Following Formation

The partnership agreement will provide that initially the Partnership will issue three types of partnership interests: (1) special GP units, representing special general partner interests, which will be issued to one of our wholly-owned subsidiaries, (2) special LP units, representing a limited partner interest, which will be owned by another newly-formed wholly-owned subsidiary of ours and (3) a managing general partner interest which has associated incentive distribution rights, or IDRs, which will be held by Fertilizer GP as managing general partner.

Special units. The special units will be comprised of special GP units and special LP units. We will own all 30,303,000 special GP units and all 30,333 special LP units. The special GP units will be special general partner interests giving the holder thereof specified joint management rights (which we refer to as special GP rights), including rights with respect to the appointment, termination and compensation of the chief executive officer and the chief financial officer of the managing general partner, and entitling the holder to participate in Partnership distributions and allocations of income and loss. Special LP units have identical voting and distribution rights as the special GP units, but represent limited partner interests in the Partnership and do not give the holder thereof the special GP rights. The limited partner interests are being issued because the Delaware Revised Uniform Partnership Act requires there to be at least one limited partner in a limited partnership to prevent such limited partnership from automatically dissolving. The special units will be entitled to payment of a set target distribution of $0.4313 per unit ($13.1 million in the aggregate for all our special units each quarter), or $1.7252 per unit on an annualized basis ($52.3 million in the aggregate for all our special units annually), prior to the payment of any quarterly distribution in respect of the IDRs. The target distribution of $0.4313 was set based upon the relationship of that amount to the minimum quarterly distribution, as described under Cash Distributions by the Partnership Distributions from Operating Surplus. Due to the various restrictions on distributions in respect of the IDRs, it is likely to be a number of years before there will be any cash distributions made in respect of the IDRs. For more information on cash distributions to the special units and the IDRs please see Cash Distributions by the Partnership. We will be permitted to sell the special units at any time without the consent of the managing general partner, subject to compliance with applicable securities laws, but upon any sale of special GP units to an unrelated third party the special GP rights will no longer apply to such units.

Managing general partner interest. The managing general partner interest, which will be held solely by Fertilizer GP, as managing general partner, will entitle the holder to manage (subject to our special GP rights) the business and operations of the Partnership, but will not entitle the holder to participate in Partnership distributions or allocations except in respect of associated incentive distribution rights, or IDRs. IDRs represent the right to receive an increasing percentage of quarterly

distributions of available cash from operating surplus after the target distribution ($0.4313 per unit per quarter) has been paid and following distribution of the aggregate adjusted operating surplus generated by the Partnership during the period from its formation through December 31, 2009 to the special units and/or the common and subordinated units (if issued). In addition, there will be no distributions paid on the managing general partner s IDRs for so long as the Partnership or its subsidiaries are guarantors under our credit facilities. The IDRs will not be transferable apart from the general partner interest. The managing general partner can be sold without the consent of other partners in the Partnership.

Initial Offering Transactions

Under the partnership agreement, the managing general partner has the sole discretion to cause the Partnership to undertake an initial private or public offering, subject to our joint management rights (as holder of the special GP rights, described below) if the offering involves the issuance of more than $200 million of the Partnership s interests (exclusive of the underwriters overallotment option, if any). There is no assurance that the Partnership will undertake or consummate a public or private offering.

Under the contribution agreement, if Fertilizer GP elects to cause the Partnership to undertake an initial private or public offering (in either case, the Partnership s initial offering), Fertilizer GP must give prompt notice to us of such election and the proposed terms of the offering. We have agreed to use our commercially reasonable efforts to take such actions as Fertilizer GP reasonably requests in order to effectuate and permit the consummation of the offering. We have agreed that Fertilizer GP may structure the initial offering to include (1) a secondary offering of interests by us or (2) a primary offering of interests by the Partnership, possibly together with an incurrence of indebtedness by the Partnership, where a use of proceeds is to redeem units from us (with a per-unit redemption price equal to the price at which each unit is purchased from the Partnership, net of sales commissions or underwriting discounts) (a special GP offering), provided that in either case the number of units associated with the special GP offering is reasonably expected by Fertilizer GP to generate no more than $100 million in net proceeds to us (exclusive of the underwriters overallotment option, if any). The special GP offering may not be consummated without our consent if the net proceeds to us are less than $10 per unit. If the initial public offering includes a special GP offering, unless we otherwise agree with the Partnership, the special GP offering will be increased to cover our pro rata portion of any exercise of the underwriters overallotment option, if any.

Under the contribution agreement, if Fertilizer GP reasonably determines that, in order to consummate the initial offering, it is necessary or appropriate for the Partnership and its subsidiaries to be released from their obligations under our credit facilities and our swap arrangements with J. Aron, then Fertilizer GP must give prompt written notice to us describing the requested amendments. The notice must be given 90 days prior to the anticipated closing date of the initial offering. We will be required to use our commercially reasonable efforts to effect the releases or amendments. We will not be considered to have made commercially reasonable efforts if we do not effect such requested modifications due to (i) payment of fees to the lenders or the swap counterparty, (ii) the costs of this type of amendment, (iii) an increase in applicable margins or spreads or (iv) changes to the terms required by the lenders including covenants, events of default and repayment and prepayment provisions; provided that (i), (ii), (iii) and (iv) in the aggregate are not likely to have a material adverse effect on us. In order to effect the requested modifications, we may require that (1) the initial offering include a special GP offering generating at least $140 million in net proceeds to us and (2) the Partnership raise an amount of cash (from the issuance of equity or incurrence of indebtedness) equal to $75 million minus the amount of capital expenditures it will reimburse us for from the proceeds of its initial public or private offering (as described in Formation Transactions) and distribute that cash to us prior to, or concurrently with, the closing of its initial public or private offering.

If the Partnership consummates an initial public or private offering and we sell units, or our units are redeemed, in a special GP offering, or the Partnership makes a distribution to us of proceeds of the offering or debt financing, such sale, redemption or distribution would likely result in taxable gain to us and such taxable gain could be significant. If the Partnership consummates an initial public or private offering, regardless of whether we sell units, the distributions that we receive from the Partnership could decrease because the Partnership s distributions will be shared with the new limited partners. Additionally, when the Partnership issues units or engages in certain other transactions, the Partnership will determine the fair market value of its assets and allocate any unrealized gain or loss attributable to those assets to the capital accounts of the existing partners. As a result of this revaluation and the Partnership s adoption of the remedial allocation method under Section 704(c) of the Internal Revenue Code (i) new unitholders will be allocated deductions as if the tax basis of the Partnership s property were equal to the fair market value thereof at the time of the offering, and (ii) we will be allocated reverse Section 704(c) allocations of income or loss over time consistent with our allocation of unrealized gain or loss.

If the Partnership consummates an initial offering as either a primary or secondary offering, our special units, other than those sold or redeemed in a special GP offering, if any, will be converted into a combination of (1) common units and (2) subordinated units. The special units will be converted into common units and subordinated units, on a one-for-one basis, such that the lesser of (1) 40% of all outstanding units after the initial offering (prior to the exercise of the underwriters overallotment option, if any) and (2) all of the units owned by us, will be subordinated. For a description of the common units and subordinated units please see Description of Partnership Interests Following Initial Offering. The special GP units will convert into common GP units or subordinated GP units and the special LP units will convert into common LP units or subordinated LP units.

The following table sets forth the number of special GP units and special LP units that will be outstanding initially and illustrates the number of common GP units, subordinated GP units, common LP units and subordinated LP units we will own, as well as the number of common LP units that public unitholders will own, assuming the Partnership s initial offering involves a total of 10 million common LP units, 7 million of which are our special units (converted into common LP units immediately prior to sale directly in the initial offering, or redeemed using the proceeds from the issuance of common LP units by the Partnership, as described above in Initial Offering Transactions) and 3 million of which are new common LP units. The following table assumes that the 7 million of our special units sold or redeemed reduce our special LP units and special GP units pro rata (i.e., 99.9% from our special GP units and 0.1% from our special LP units). This information is presented for illustrative purposes only. There can be no assurance the Partnership will undertake an initial offering consistent with these assumptions or at all.

	Initial Special Units	Following Partnership Initial Offering Common Units	Subordinated Units
Owned by us	30,303,000 special GP units	9,990,000 common GP units	13,320,000 subordinated LP units
	30,333 special LP units	10,000 common LP units	13,333 subordinated LP units
Owned by public		10,000,000 common LP units	

The partnership agreement will prohibit Fertilizer GP from causing the Partnership to undertake or consummate an initial offering unless the board of directors of Fertilizer GP determines, after consultation with us, that the Partnership will likely be able to earn and pay the minimum quarterly distribution (which is currently set at $0.375 per unit) on all units for each of the two consecutive, nonoverlapping four-quarter periods following the initial offering. As an illustration, the Partnership would need to earn and pay $50 million during each of the two consecutive, nonoverlapping four-quarter periods based upon the number of units (i.e., 33,333,333 total units) in the hypothetical illustrated in the table above. If Fertilizer GP determines that the Partnership is not likely to be able to earn and pay the minimum quarterly distribution for such periods, Fertilizer GP may, in its sole discretion and effective upon closing of the initial offering, reduce the minimum quarterly distribution to an amount it determines to be appropriate and likely to be earned and paid during such periods.

The contribution agreement also provides that if the initial offering is not consummated by the second anniversary of the consummation of this offering, Fertilizer GP can require us to purchase the managing general partner interest. This put right expires on the earlier of (1) the fifth anniversary of the consummation of this offering and (2) the closing of the Partnership s initial offering. If the Partnership s initial offering is not consummated by the fifth anniversary of the consummation of this offering, we have the right to require Fertilizer GP to sell the managing general partner interest to us. This call right expires on the closing of the Partnership s initial offering. In the event of an exercise of a put right or a call right, the purchase price will be the fair market value of the managing general partner interest at the time of purchase. The fair market value will be determined by an independent investment banking firm selected by us and Fertilizer GP. The independent investment banking firm may consider the value of the Partnership s assets, the rights and obligations of Fertilizer GP and other factors it may deem relevant but the fair market value shall not include any control premium. See Risk Factors Risks Related to the Limited Partnership Structure Through Which We Will Hold Our Interest in the Nitrogen Fertilizer Business If the Partnership does not consummate an initial offering within two years after the consummation of this offering, Fertilizer GP can require us to purchase its managing general partner interest in the Partnership. We may not have requisite funds to do so.

Description of Partnership Interests Following Initial Offering

Common units. The common units, if issued, will be comprised of common GP units and common LP units. The common GP units will be special general partner interests giving the holder special GP rights (described below), including rights with respect to the appointment, termination and compensation of the chief executive officer and the chief financial officer of the managing general partner, and entitling the holder to participate in Partnership distributions and allocations on a pro rata basis with common LP units. Common LP units will have identical voting and distribution rights as the common GP units, but will represent limited partner interests in the Partnership and will not give the holder thereof special GP rights. The common units will be entitled to payment of the minimum quarterly distribution prior to the payment of any quarterly distribution on the subordinated units or the IDRs. For more information of the rights and preferences of holders of the common units, subordinated units and IDRs in the Partnership s distributions, please see Cash Distributions by the Partnership.

We will be permitted to sell the common units we own at any time without the consent of the managing general partner, subject to compliance with applicable securities laws. The common GP units will automatically convert to common LP units immediately prior to sale thereof to an unrelated third party. The common GP units will automatically convert into common LP units (with no special GP rights) immediately if the holder of the common GP units, together with all of its affiliates, ceases to own 15% or more of all units of the Partnership (not including the managing general partner interest).

Subordinated units. The subordinated units, if issued, will be comprised of subordinated GP units and subordinated LP units. The subordinated GP units will be special general partner interests giving the holder special GP rights. Subordinated LP units will have identical voting and distribution rights as the subordinated GP units, but will represent limited partner interests in the Partnership and will not give the holder thereof special GP rights. The subordinated units will entitle the holder to participate in Partnership distributions and allocations on a subordinated basis to the common units (as described in Cash Distributions by the Partnership). During the subordination period (as defined in Cash Distributions by the Partnership Distributions from Operating Surplus Subordination Period), the subordinated units will not be entitled to receive any distributions until the common units have received the set minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. As a result, if the Partnership consummates an initial offering, the portion of our special units that are converted into subordinated units will be subordinated to the common units and may not receive distributions unless and until the common units have received the minimum quarterly distribution, plus any accrued and

unpaid arrearages in the minimum quarterly distribution from prior quarters. See Risk Factors Risks Related to the Limited Partnership Structure Through Which We Will Hold Our Interest In the Nitrogen Fertilizer Business Our rights to receive distributions from the Partnership may be limited over time and Risk Factors Risks Related to the Limited Partnership Structure Through Which We Will Hold Our Interest In the Nitrogen Fertilizer Business If the Partnership completes a public offering or private placement of limited partner interests our voting power in the Partnership would be reduced and our rights to distributions from the Partnership would be adversely affected.

We will be permitted to sell the subordinated units we own at any time without the consent of the managing general partner, subject to compliance with applicable securities laws. The subordinated units will automatically convert into common units on the second day after the distribution of cash in respect of the last quarter in the subordination period (which will end no earlier than five years after the initial offering), although up to 50% may convert earlier. The subordinated GP units will automatically convert to subordinated LP units immediately prior to sale thereof to an unrelated third party. The subordinated GP units will automatically convert into subordinated LP units immediately if the holder of the subordinated GP units, together with all of its affiliates, ceases to own 15% or more of all units of the Partnership.

Managing general partner interest. The managing general partner interest will continue to be outstanding following the initial offering.

Management of the Partnership

Fertilizer GP, as the managing general partner, will manage the Partnership s operations and activities, subject to our specified joint management rights. Among other things, the managing general partner will have sole authority to effect an initial public or private offering, including the right to determine the timing, size (subject to our joint management rights for any initial offering in excess of $200 million, exclusive of the underwriters overallotment option, if any) and underwriters or initial purchasers, if any, for any initial offering. Fertilizer GP is wholly owned by a newly created entity controlled by the Goldman Sachs Funds, the Kelso Funds and our senior management. The operations of Fertilizer GP, in its capacity as managing general partner, are managed by its board of directors. The managing general partner of the Partnership is not elected by the unit holders or us and will not be subject to re-election on a regular basis in the future.

The holders of special GP units (and/or common GP units and subordinated GP units, if any) have special GP rights. Upon consummation of this offering and the formation of the Partnership, we will hold all of the special GP units. The special GP rights will terminate if we cease to own 15% of more of all units of the Partnership, because the special GP units (or common GP units and subordinated GP units) will automatically convert to limited partner interests as described above. The special GP rights include:

- joint appointment rights and consent rights for the termination of employment and compensation of the chief executive officer and chief financial officer of the managing general partner, not to be exercised unreasonably (our approval for appointment of an officer is deemed given if the officer is an executive officer of CVR Energy);

- the right to appoint two directors to the board of directors (or comparable governing body) of the managing general partner and one such director to any committee thereof (subject to certain exceptions);

- joint management rights over any merger by the Partnership into another entity where:

  - for so long as we own 50% or more of all units of the Partnership immediately prior to the merger, less than 60% of the equity interests of the resulting entity are owned by the pre-merger unit holders of the

Partnership;

- for so long as we own 25% or more of all units of the Partnership immediately prior to the merger, less than 50% of the equity interests of the resulting entity are owned by the pre-merger unit holders of the Partnership; and

- for so long as we own more than 15% of the all units of the Partnership immediately prior to the merger, less than 40% of the equity interests of the resulting entity are owned by the pre-merger unit holders of the Partnership;

- joint management rights over any fundamental change in the business of the Partnership from that conducted by the nitrogen fertilizer business;

- joint management rights over any purchase or sale, exchange or other transfer of assets or entities with a purchase/sale price equal to 50% or more of the current asset value of the Partnership; and

- joint management rights over any incurrence of indebtedness or issuance of Partnership interests with rights to distribution or in liquidation ranking prior or senior to the common units, in either case in excess of $125 million ($200 million in the case of the Partnership s initial public or private offering, exclusive of the underwriters overallotment option, if any), increased by 80% of the purchase price for assets or entities whose purchase was approved by us as described in the immediately preceding bullet point.

Upon consummation of this offering, the board of directors of the managing general partner will consist of six directors, including two representatives of the Goldman Sachs Funds, two representatives of the Kelso Funds, and two of our representatives. If the Partnership effects an initial public offering in the future, the board of directors of the managing general partner will be required, subject to phase-in requirements of any national securities exchange upon which the Partnership s common units are listed for trading, to have at least three members who are not officers or employees, and are otherwise independent, of the entity which owns the managing general partner, and its affiliates, including CVR Energy and the Partnership s general partners. In addition, if an initial public offering of the Partnership occurs, the board of directors of the managing general partner will be required to maintain an audit committee comprised of at least three independent directors.

The partnership agreement will permit the board of directors of the managing general partner to establish a conflicts committee, comprised of at least one independent director (if any), that may determine if the resolution of a conflict of interest with the Partnership s general partners or their affiliates is fair and reasonable to the Partnership. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all of the Partnership s partners and not a breach by the general partners of any duties they may owe the Partnership or the unit holders of the Partnership.

Cash Distributions by the Partnership

Distributions of Available Cash

Available Cash. The partnership agreement will require the Partnership to make quarterly distributions of 100% of its available cash. Available cash is defined as all cash on hand at the end of any particular quarter less (i) the amount of any cash reserves established by the managing general partner to (a) provide for the proper conduct of the Partnership s business (including the satisfaction of obligations in respect of pre-paid fertilizer contracts, future capital expenditures and anticipated future credit needs), (b) comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation to which the Partnership or any of its subsidiaries is a party or by which it is bound or its assets are subject or (c) provide funds for distributions in respect of any one or more of the next eight quarters; plus (ii) working capital borrowings, if any. Working capital borrowings are generally borrowings that are used solely for working capital purposes or to make distributions to partners. Cash distributions will be made within 45 days after the end of each quarter. The amount of distributions paid by the Partnership and the

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decision to make any distribution will be determined by the managing general partner, taking into consideration the terms of the partnership agreement.

Prior to the earlier to occur of (i) such time as the limitations described below in Non-IDR surplus amount no longer apply, after which time available cash from operating surplus could be distributed in respect of the IDRs, assuming each unit has received at least the first target distribution, as described below, and (ii) an initial offering by the Partnership, after which there will be limited partners to whom available cash could be distributed, all available cash will be distributed to us, as holder of the special units. Because all available cash will initially be distributed to us, the board of directors of Fertilizer GP has not adopted a formal distribution policy.

Operating Surplus, Capital Surplus and Adjusted Operating Surplus

General. All cash distributed by the Partnership will be characterized either as operating surplus or capital surplus. The Partnership will distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of operating surplus. Operating surplus will be defined, generally, as:

$60 million; plus

all of the Partnership s cash receipts after formation (reset to the date of the Partnership s initial offering if an initial offering occurs), excluding cash from (i) borrowings that are not working capital borrowings, (ii) sales of equity interests and debt securities and (iii) sales or other dispositions of assets outside the ordinary course of business; plus

interest (after giving effect to any interest rate swap agreements) paid on debt incurred by the Partnership, and cash distributions paid on the equity interests issued by the Partnership, in each case, to finance all or any portion of the construction, expansion or improvement of its facilities during the period from such financing until the earlier to occur of the date the capital asset is put into service or the date it is abandoned or disposed of; plus

interest (after giving effect to any interest rate swap agreements) paid on debt incurred by the Partnership, and cash distributions paid on the equity interests issued by the Partnership, in each case, to pay the construction period interest on debt incurred, or to pay construction period distributions on equity issued, to finance the construction projects referred to above; plus

working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; less

all of the Partnership s operating expenditures (as defined below) after formation (reset to the date of closing of the Partnership s initial offering if an initial offering occurs); less

the amount of cash reserves established by the managing general partner to provide funds for future operating expenditures (which does not include capital expenditures for acquisitions or for capital improvements).

If a working capital borrowing, which increases operating surplus, is not repaid during the twelve month period following the borrowing, it will be deemed repaid at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowing is in fact repaid, it will not be treated as a reduction in operating surplus because operating surplus will have been previously reduced by the deemed repayment.

Operating expenditures generally means all of the Partnership s expenditures, including, but not limited to, taxes, reimbursement of expenses of the managing general partner, repayment of working capital borrowings, debt service payments and capital expenditures, but will not include payments of principal of and premium on indebtedness other than working capital borrowings, capital expenditures made for acquisitions or for capital improvements, payment of transaction expenses relating to interim capital transactions (as defined below) or distributions to partners. Where capital expenditures are made in part for acquisitions or for capital improvements and in part for other purposes, the Partnership s managing general partner will determine the allocation between the amounts paid for each.

Interim Capital Transactions means the following transactions if they occur prior to the liquidation of the Partnership: (a) borrowings, refinancings or refundings of indebtedness (other than working capital borrowings and other than for items purchased on open account or for a deferred purchase price in the ordinary course of business); (b) sales of equity interests and debt securities; and (c) sales or other voluntary or involuntary dispositions of any assets other than (i) sales or other dispositions of inventory, accounts receivable and other assets in the ordinary course of business, and (ii) sales or other dispositions of assets as part of normal retirements or replacements of assets.

Maintenance capital expenditures reduce operating surplus (from which the Partnership makes the minimum quarterly distribution) but capital expenditures for acquisitions and capital improvements do not. Maintenance capital expenditures represent capital expenditures to replace partially or fully depreciated assets to maintain the operating capacity (or productivity) or capital base of the Partnership. Maintenance capital expenditures include expenditures required to maintain equipment reliability, plant integrity and safety and to address environmental regulations. Capital improvement expenditures include expenditures to acquire or construct assets to grow the Partnership s business and to expand existing fertilizer production capacity. 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. The Partnership s managing general partner will determine how to allocate a capital expenditure for the acquisition or expansion of the Partnership s assets between maintenance capital expenditures and capital improvement expenditures.

Distributions from Operating Surplus

The Partnership s distribution structure with respect to operating surplus will change based upon the occurrence of three events: (1) distribution by the Partnership of the non-IDR surplus amount (as defined below), together with a release of the guarantees by the Partnership and its subsidiaries of our credit facilities, (2) occurrence of an initial offering by the Partnership (following which all or a portion of our interest will be converted into subordinated units and the minimum quarterly distribution could be reduced) and (3) expiration (or early termination) of the subordination period.

Minimum Quarterly Distributions. The minimum quarterly distribution, or MQD, represents the set quarterly distribution amount that the common units, if issued, will be entitled to prior to the payment of any quarterly distribution on the subordinated units. The amount of the MQD will initially be set in the Partnership s partnership agreement at $0.375 per unit, or $1.50 per unit on an annualized basis. The MQD amount of $0.375 per unit was selected as an amount that could be earned and paid on all units to be initially outstanding following this offering and sustainable for the foreseeable future. We based this amount upon the historical results of operations of our nitrogen fertilizer business and projected cash flows and operating expenditures of the Partnership. The partnership agreement will prohibit Fertilizer GP from causing the Partnership to undertake or consummate an initial offering unless the board of directors of Fertilizer GP, after consultation with us, concludes that the Partnership will be likely to be able to earn and pay the MQD on all units for each of the two consecutive, nonoverlapping four-quarter periods following the initial offering. If Fertilizer GP determines that the Partnership is not likely to be able to earn and pay the MQD for such periods, Fertilizer GP may, in its sole discretion and effective upon closing of the initial offering, reduce the MQD to an amount it determines to be appropriate and likely to be earned and paid during such periods. If the Partnership were to distribute $0.375 per unit on the number of units we will initially own, we would receive a quarterly distribution of $11.4 million in the aggregate. The MQD for any period of less than a full calendar quarter (e.g., the periods before and after the closing of an initial offering by the Partnership) will be adjusted based on the actual length of the periods. To the extent we receive amounts from the Partnership in the form of quarterly distributions, we will generally not be

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able to distribute such amounts to our stockholders due to restrictions contained in our credit facilities. See Dividend Policy.

Target Distributions. The Partnership s partnership agreement provides for target distribution levels. After the limitations described below in Non-IDR surplus amount no longer apply, Fertilizer GP s IDRs will entitle it to receive increasing percentages of any incremental quarterly cash distributed by the Partnership as the target distribution levels for each quarter are exceeded. There will be three target distribution levels set in the partnership agreement: $0.4313, $0.4688 and $0.5625, representing 115%, 125% and 150%, respectively, of the initial MQD amount. See Distributions Prior to the Partnership s Initial Offering (if any) and see Distributions After the Partnership s Initial Offering (if any). The target distribution levels for any period of less than a full calendar quarter (e.g., the periods before and after the closing of an initial offering by the Partnership) will be adjusted based on the actual length of the periods. The target distribution levels will not be adjusted in connection with any reduction of the MQD in connection with the Partnership s initial offering (as discussed under Minimum Quarterly Distributions) unless we otherwise agree with Fertilizer GP.

The following table illustrates the percentage allocations of available cash from operating surplus between the unit holders and the Partnership s managing general partner up to and above the various target distribution levels. The amounts set forth under marginal percentage interest in distributions are the percentage interests of the Partnership s managing general partner and the unit holders in any available cash from operating surplus the Partnership distributes up to and including the corresponding amount in the column total quarterly distribution, until the available cash from operating surplus the Partnership distributes reaches the next target distribution level, if any. The percentage interests shown for the unit holders and managing general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for the managing general partner represent distributions in respect of the IDRs.

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	Special Units; Common and Subordinated Units	Managing General Partner
Minimum Quarterly Distribution	$0.375	100%	0%
First Target Distribution	up to $0.4313	100%	0%
Second Target Distribution	above $0.4313 and up to $0.4688	87%	13%
Third Target Distribution	above $0.4688 and up to $0.5625	77%	23%
Thereafter	above $0.5625	52%	48%

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels. In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus (see Distributions from Capital Surplus), and a potential reduction of the MQD in connection with the Partnership s initial offering (as discussed under Minimum Quarterly Distributions), if the Partnership combines its units into fewer units or subdivides its units into a greater number of units, the Partnership will proportionately adjust:

- the minimum quarterly distribution;

the target distribution levels; and

the initial unit price, as described below under Distributions of Cash Upon Liquidation.

For example, if a two-for-one split of the common and subordinated units should occur, the minimum quarterly distribution, the target distribution levels and the initial unit price would each be reduced to 50% of its initial level. If the Partnership combines its common units into fewer units or subdivides its common units into a greater number of units, the Partnership will combine its subordinated units or subdivide its subordinated units, using the same ratio applied to the common units. The Partnership will not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a court of competent jurisdiction so that the Partnership or any of its subsidiaries becomes taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, the managing general partner may, in its sole discretion, reduce the minimum quarterly distribution and the target distribution levels for each quarter by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter (after deducting the managing general partner s estimate of the Partnership s aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation) and the denominator of which is the sum of available cash for that quarter plus the managing general partner s estimate of the Partnership s aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Non-IDR surplus amount. There will be no distributions paid on the IDRs until the aggregate adjusted operating surplus (as described below) generated by the Partnership during the period from its formation through December 31, 2009, or the non-IDR surplus amount, has been distributed in respect of the special units and/or the common and subordinated units (if any are issued). In addition, there will be no distributions paid on the IDRs for so long as the Partnership or its subsidiaries are guarantors under our credit facilities.

Limitation on increases in regular quarter distributions. After the limitations described in Non-IDR surplus amount no longer apply, the managing general partner will not be permitted to increase the Partnership s regular quarterly distribution (calculated on a per-unit basis), unless the managing general partner determines that the increased per-unit distribution rate is likely to be sustainable for at least the succeeding two years. This restriction will not apply to any special distributions declared by the managing general partner or any distributions in the nature of a full or partial liquidation of the Partnership.

Distributions Prior to the Partnership s Initial Offering (if any). Prior to the Partnership s initial offering (if any), quarterly distributions of available cash from operating surplus (as described below) will be paid solely in respect of the special units until the non-IDR surplus amount has been distributed.

After the limitations described in Non-IDR surplus amount no longer apply and prior to the Partnership s initial offering (if any), quarterly distributions of available cash from operating surplus will be paid in the following manner:

First, to the special units, until each special unit has received a total quarterly distribution equal to $0.4313 (the first target distribution);

Second, (i) 13% to the managing general partner interest (in respect of the IDRs) and (ii) 87% to the special units until each special unit has received a total quarterly amount equal to $0.4688 (the second target distribution);

Third, (i) 23% to the managing general partner interest (in respect of the IDRs) and (ii) 77% to the special units, until each special unit has received a total quarterly amount equal to $0.5625 (the third target distribution); and

Thereafter, (i) 48% to the managing general partner interest (in respect of the IDRs) and (ii) 52% to the special units.

Distributions After the Partnership s Initial Offering (if any). If the non-IDR surplus amount has not been distributed at the time of the Partnership s initial offering, quarterly distributions of available

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cash from operating surplus after the initial offering will be paid in the following manner until the non-IDR surplus amount has been distributed:

First, to the common units, until each common unit has received an amount equal to the MQD plus any arrearages from prior quarters;

Second, to the subordinated units, until each subordinated unit has received an amount equal to the MQD; and

Thereafter, to all common units and subordinated units, pro rata.

After the limitations described in Non-IDR surplus amount no longer apply, after the Partnership s initial offering (if any) and during the subordination period, quarterly distributions of available cash from operating surplus will be paid in the following manner:

First, to all common units, until each common unit has received a total quarterly distribution equal to the MQD plus any arrearages for prior quarters;

Second, to all subordinated units, until each subordinated unit has received a total quarterly distribution equal to the MQD;

Third, to all common units and subordinated units, pro rata, until each common unit and subordinated unit has received a total quarterly distribution equal to $0.4313 (excluding any distribution in respect of arrearages) (the first target distribution);

Fourth, (i) 13% to the managing general partner interest (in respect of the IDRs) and (ii) 87% to all common units and subordinated units, pro rata, until each common unit and subordinated unit has received a total quarterly distribution equal to $0.4688 (excluding any distribution in respect of arrearages) (the second target distribution);

Fifth, (i) 23% to the managing general partner interest (in respect of the IDRs) and (ii) 77% to all common units and subordinated units, pro rata, until each common unit and subordinated unit has received a total quarterly distribution equal to $0.5625 (excluding any distribution in respect of arrearages) (the third target distribution); and

Thereafter, (i) 48% to the managing general partner interest (in respect of the IDRs) and (ii) 52% to all common units and subordinated units, pro rata.

After the limitations described in Non-IDR surplus amount no longer apply, after the Partnership s initial offering (if any) and after the subordination period (when all of our subordinated units automatically convert into common units), quarterly distributions of available cash from operating surplus will be paid in the following manner:

First, to all common units, until each common unit has received a total quarterly distribution equal to $0.4313 (the first target distribution);

Second, (i) 13% to the managing general partner interest (in respect of the IDRs) and (ii) 87% to all common units, pro rata, until each common unit has received a total quarterly distribution equal to $0.4688 (the second target distribution);

Third, (i) 23% to the managing general partner interest (in respect of the IDRs) and (ii) 87% to all common units, pro rata, until each common unit has received a total quarterly distribution equal to $0.5625 (the third target distribution); and

Thereafter, (i) 48% to the managing general partner interest (in respect of the IDRs) and (ii) 52% to all common units, pro rata.

Subordination period. The subordination period can occur only after the initial offering of the Partnership, when all or a portion of our special units convert into subordinated units. Accordingly, a subordination period may never occur. During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the

MQD, plus any arrearages in the payment of the MQD on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units held by us. The subordinated units will be deemed subordinated because during the subordination period, the subordinated units will not be entitled to receive distributions until the common units have received the MQD plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units.

The subordination period will generally extend until the second day after the Partnership has met the tests specified in the partnership agreement. The tests generally require:

- the Partnership to have earned and paid the MQD on all of the Partnership s outstanding units during specified periods; and

- there to be no arrearages in payment of the MQD on the common units.

By earning the MQD, we mean that the Partnership has generated a sufficient amount of adjusted operating surplus during the specified periods to pay the MQD on all of the outstanding units on a fully diluted basis. By paying the MQD, we mean that the Partnership has actually made distributions of available cash from operating surplus on each outstanding unit in an amount that equals or exceeds the MQD in respect of each quarter in the specified periods.

The subordination period will generally extend for at least five years after the date of the initial offering (if any) of the Partnership and will end the second day after the date when the Partnership has earned and paid the MQD for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date and there are no arrearages in payment of the MQD on the common units.

25% of the subordinated units may convert into common units early (before the end of the subordination period) if, on a date at least three years after the Partnership s initial offering, the Partnership has earned and paid the MQD for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date and there are no arrearages in payment of the MQD on the common units.

An additional 25% of the subordinated units may convert into common units early if, on a date at least four years after the Partnership s initial offering, the Partnership has earned and paid the MQD for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date and there are no arrearages in payment of the MQD on the common units, provided, that the last four-quarter period cannot include any quarter included in the periods used for conversion of the first 25% of the subordinated units.

Furthermore, if the unit holders remove the Partnership s managing general partner other than for cause and no units held by us and our affiliates are voted in favor of such removal, (1) the subordination period will end and each subordinated unit will immediately convert into one common unit, and (2) any existing arrearages in payment of the MQD on the common units will be extinguished.

Definition of adjusted operating surplus. Adjusted operating surplus will be defined, generally, for any period as:

- operating surplus generated with respect to that period; less

- any net increase in working capital borrowings with respect to that period; less

- any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus any net decrease in working capital borrowings with respect to that period; plus

any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

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Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods.

Distributions from Capital Surplus

Capital surplus is generally generated only by borrowings other than working capital borrowings, sales of debt securities and equity interests, and sales or other dispositions of assets for cash, other than inventory, accounts receivable and the other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

The Partnership will make distributions of available cash from capital surplus, if any, in the following manner:

First, to all unit holders, pro rata, until the minimum quarterly distribution is reduced to zero, as described below;

Second, to the common unit holders, if any, pro rata, until the Partnership distributes for each common unit an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and

Thereafter, the Partnership will make all distributions of available cash from capital surplus as if they were from operating surplus.

The preceding discussion is based on the assumptions that the Partnership does not issue additional classes of equity interests.

The partnership agreement will treat a distribution of capital surplus as the repayment of the consideration for the issuance of a unit by the Partnership, which is a return of capital. Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the distribution had in relation to the fair market value of the common units prior to the announcement of the distribution. Because distributions of capital surplus will reduce the minimum quarterly distribution, after any of these distributions are made, it may be easier for the managing general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution of capital surplus before the minimum quarterly distribution is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once the Partnership reduces the minimum quarterly distribution and the target distribution levels to zero, the Partnership will then make all future distributions from operating surplus, with 52% being paid to the unit holders, pro rata, and 48% to the Partnership s managing general partner.

Unaudited Pro Forma Available Cash

If the nitrogen fertilizer business had been contributed to the Partnership on January 1, 2006, we estimate that the Partnership s pro forma available cash generated during 2006 would have been approximately $59.3 million. This amount would have been in excess of the amount necessary for the Partnership to make cash distributions for 2006 at a rate of $0.375 per unit per quarter (or $1.50 per unit on an annualized basis) on the 30,333,333 special units we will initially own. Because all available cash will initially be distributed to us, as described above under Distributions of Available Cash the board of directors of Fertilizer GP has not adopted a formal distribution policy. The minimum quarterly distribution specified in the Partnership s partnership agreement could be reduced without our consent under certain circumstances or could be increased with our consent, and the Partnership could issue additional units. This information is presented for illustrative purposes only.

This pro forma available cash is derived from unaudited segment operating data for our nitrogen fertilizer segment and is based on specific estimates and assumptions. The pro forma amounts do not purport to present results of operations for the Partnership had the transactions contemplated below actually been completed as of January 1, 2006. Furthermore, available cash is primarily a cash

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accounting concept, while our unaudited nitrogen fertilizer segment operating data have been prepared on an accrual basis. We derived the amounts of pro forma available cash stated above in the manner described in the table below. As a result, the amount of pro forma available cash should only be viewed as a general indication of the amount of available cash that the Partnership might have generated had it been formed and completed the transactions contemplated below in 2006 and had it been operated in a manner consistent with that described in the footnotes.

The following table illustrates the Partnership s cash available for distribution, on a pro forma basis for 2006, assuming:

our nitrogen fertilizer business was contributed to the Partnership on January 1, 2006;

the agreements described in Other Intercompany Agreements were entered into on January 1, 2006; and

the termination of the management agreements with Goldman, Sachs & Co. and Kelso and Company, L.P. occurred on or prior to December 31, 2005.

Each of the pro forma adjustments presented below is explained in the footnotes to such adjustments.

CVR Partners, LP
Unaudited Pro Forma Cash Available to Make Distributions

	Nitrogen Fertilizer Segment Cash Flow for the Year Ended December 31, 2006 (Unaudited)	Pro Forma Adjustments (Unaudited)	Pro Forma Nitrogen Fertilizer Segment Cash Flow for the Year Ended December 31, 2006 (Unaudited)
Net sales	$ 162,464,532	$	$ 162,464,532
Operating costs and expenses:			
Cost of product sold (exclusive of depreciation & amortization)	25,898,902	(3,494,618)(a)	22,404,284
Direct operating expenses (exclusive of depreciation and amortization)	63,683,224	(72,451)(b)	63,610,773
Selling, general and administrative expenses (exclusive of depreciation & amortization)	18,914,256	(6,876,482)(c)	12,037,774
Depreciation and amortization	17,125,898		17,125,898
Total operating costs and expenses	125,622,280	(10,443,551)	115,178,729
Operating income	36,842,252	10,443,551	47,285,803
Other income (expense)	180,680		180,680
Income (loss) before provision for income taxes	37,022,932	10,443,551	47,466,483
Adjustments to Cash			
Depreciation	17,106,734		17,106,734
Amortization	19,164		19,164

Capital expenditures	(13,257,681)		(13,257,681)
Revolving credit borrowings to fund discretionary capital expenditures		8,917,655(d)	8,917,655

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	Nitrogen Fertilizer Segment Cash Flow for the Year Ended December 31, 2006 (Unaudited)	Pro Forma Adjustments (Unaudited)	Pro Forma Nitrogen Fertilizer Segment Cash Flow for the Year Ended December 31, 2006 (Unaudited)
Changes in working capital	(1,990,000)		(1,990,000)
Gain/loss on the Disposition of Assets	1,056,791		1,056,791
Total adjustments to cash flow	2,935,008	8,917,655	11,852,663
Cash available for distribution	$ 39,957,940	$ 19,361,206	$ 59,319,146

a) Reflects the lower price for pet coke to be supplied by the refinery to the Partnership under the terms of the coke supply agreement to be entered into between us and the Partnership. The actual results for the year ended December 31, 2006 included a coke transfer price of $15 per short ton of coke. The price would have been $5 per ton under the terms of the coke supply agreement. The refinery transferred 349,462 tons of pet coke to the nitrogen fertilizer segment during the year ended December 31, 2006. Under the terms of the coke supply agreement the Partnership would not have been required to purchase more than 349,462 tons of pet coke.

b) Represents a decrease in costs of general environmental insurance allocable to the Partnership under the terms of the services agreement. The actual results for the year ended December 31, 2006 reflect a simple 1/3 allocation to the nitrogen fertilizer segment. The allocation under the services agreement would have been based on payroll.

c) Represents a lower allocation of selling general and administrative expenses under the terms of the services agreement. The actual results for the year ended December 31, 2006 reflect a simple 1/3 allocation to the nitrogen fertilizer segment. The allocation under the services agreement would have been based on payroll. In addition, the pro forma adjustment reflects the reversal of the allocation to the nitrogen fertilizer segment of a portion of a related party management fee which will not be included in actual charges for future years. The pro forma selling, general and administrative expenses does not include any estimated incremental general and administrative expenses that we expect the Partnership would incur if the Partnership were a publicly traded partnership, such as costs associated with annual and quarterly reports to unit holders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, investor relations activities, registrar and transfer agent fees, SEC reporting and filing requirements, incremental director and officer liability insurance costs and director compensation. We estimate that these incremental general and administrative expenses would not exceed approximately $2.0 million per year.

d) For purposes of determining pro forma cash available for distribution, we have assumed that the Partnership was operated during 2006 consistent with the manner in which we assume it would operate as a publicly traded partnership, including borrowing the amounts necessary to cover discretionary capital expenditures, as well as interest payments on such borrowings, as reflected in the table. The nitrogen fertilizer segment incurred significant expenditures related to discretionary capital expenditure projects which we assume would not have been funded from cash from operations if the Partnership were operated as a publicly traded partnership. We assume the Partnership would either reserve adequate cash to complete discretionary capital expenditures or would raise additional capital to fund projects that are not required to sustain operations. The managing general partner will determine how capital expenditures will be funded.

The pro forma financial data described above indicates that the Partnership would have had sufficient net available cash during 2006 in order to pay the minimum quarterly distribution during 2006. For 2007, the Company does not know of any demands, commitments, events or uncertainties

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that are reasonably likely to cause the Partnership s available cash to decrease in a material way during 2007 (although the flood resulted in damage to the nitrogen fertilizer facilities and caused a cessation of business operations during part of July 2007). In addition, the Partnership s partnership agreement includes a provision that the Partnership may not consummate an initial offering unless the managing general partner believes that the Partnership will be able to pay the minimum quarterly distribution for at least two years.

Distributions of Cash Upon Liquidation

General. If the Partnership dissolves in accordance with the partnership agreement, the Partnership will sell or otherwise dispose of its assets in a process called liquidation. The Partnership will first apply the proceeds of liquidation to the payment of its creditors. The Partnership will distribute any remaining proceeds to the unit holders and the managing general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of the Partnership s assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of units to a repayment of the initial value contributed by the unit holder to the Partnership for its units, which we refer to as the initial unit price for each unit. With respect to our special units, the initial unit price will be the value of the nitrogen fertilizer business we contribute to the Partnership, divided by the number of special units we receive. The initial unit price for the common units issued by the Partnership in the initial offering, if any, will be the price paid for the common units. If there are common units and subordinated units outstanding, the allocation is intended, to the extent possible, to entitle the holders of common units to a preference over the holders of subordinated units upon the Partnership s liquidation, to the extent required to permit common unit holders to receive their initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon the Partnership s liquidation to enable the holders of units, including us, to fully recover all of the initial unit price. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of the managing general partner.

Manner of Adjustments for Gain. The manner of the adjustment for gain is set forth in the partnership agreement. If the Partnership s liquidation occurs after the Partnership s initial offering, if any, and before the end of the subordination period, the Partnership will allocate any gain to the partners in the following manner:

First, to the managing general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

Second, to the common unit holders, pro rata, until the capital account for each common unit is equal to the sum of:

(1) the initial unit price;

(2) the amount of the minimum quarterly distribution for the quarter during which the liquidation occurs; and

(3) any unpaid arrearages in payment of the minimum quarterly distribution;

Third, to the subordinated unit holders, pro rata, until the capital account for each subordinated unit is equal to the sum of:

(1) the initial unit price; and

(2) the amount of the minimum quarterly distribution for the quarter during which the liquidation occurs;

Fourth, to all unit holders, pro rata, until the Partnership allocates under this paragraph an amount per unit equal to:

(1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of the Partnership s existence; less

(2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that the Partnership distributed to the unit holders, pro rata, for each quarter of the Partnership s existence;

Fifth, 87% to all unit holders, pro rata, and 13% to the managing general partner, until the Partnership allocates under this paragraph an amount per unit equal to:

(1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of the Partnership s existence; less

(2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that the Partnership distributed 87% to the unit holders, pro rata, and 13% to the managing general partner for each quarter of the Partnership s existence;

Sixth, 77% to all unit holders, pro rata, and 23% to the managing general partner, until the Partnership allocates under this paragraph an amount per unit equal to:

(1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of the Partnership s existence; less

(2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that the Partnership distributed 77% to the unit holders, pro rata, and 23% to the managing general partner for each quarter of the Partnership s existence; and

Thereafter, 52% to all unit holders, pro rata, and 48% to the managing general partner.

The percentages set forth above are based on the assumption that the Partnership has not issued additional classes of equity interests.

If the liquidation occurs before the Partnership s initial offering, the special units will receive allocations of gain in the same manner as described above for the common units, except that the distinction between common units and subordinated units will not be relevant, so that clause (3) of the second bullet point above and all of the third bullet point above will not be applicable. If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

Manner of Adjustments for Losses. If the Partnership s liquidation occurs after the Partnership s initial offering, if any, and before the end of the subordination period, the Partnership will generally allocate any loss to the managing general partner and the unit holders in the following manner:

First, to holders of subordinated units in proportion to the positive balances in their capital accounts, until the capital accounts of the subordinated unit holders have been reduced to zero;

Second, to the holders of common units in proportion to the positive balances in their capital accounts, until the capital accounts of the common unit holders have been reduced to zero; and

Thereafter, 100% to the managing general partner.

If the liquidation occurs before the Partnership s initial offering, the special units will receive allocations of loss in the same manner as described above for the common units, except that the distinction between common units and subordinated units will not be relevant, so that all of the first bullet point above will not be applicable. If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

Adjustments to Capital Accounts. The Partnership will make adjustments to capital accounts upon the issuance of additional units. In doing so, the Partnership will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unit holders and the managing general partner in the same manner as the Partnership allocates gain or loss upon liquidation. In the event that the Partnership makes positive adjustments to the capital accounts upon the issuance of additional units, the Partnership will allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon the Partnership s liquidation in a manner which results, to the extent possible, in the managing general partner s capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

Other Provisions of the Partnership Agreement

In addition to the provisions regarding the formation of the Partnership, the Partnership interests that will be outstanding initially following formation and that may be issued in an initial offering by the Partnership and the relative rights and preferences of the holders of such Partnership interests in the Partnership s distributions, the Partnership s partnership agreement contains additional material provisions that set forth the various rights and responsibilities of the partners in the Partnership. The following is a summary of these additional material provisions.

Removal of the Managing General Partner

For the first five years after the consummation of this offering, the managing general partner may be removed only for cause by a vote of the holders of at least 80% of the outstanding units, including any units owned by the managing general partner and its affiliates, voting together as a single class and may not be removed without cause. Cause will be defined as a final, non-appealable judicial determination that the managing general partner, as an entity, has materially breached a material provision of the partnership agreement or is liable for actual fraud or willful misconduct in its capacity as a general partner of the Partnership.

After five years from the consummation of this offering, the managing general partner may be removed with or without cause by a vote of the holders of at least 80% of the outstanding units, including any units owned by the managing general partner and its affiliates, voting together as a single class.

The partnership agreement also provides that if the managing general partner is removed as managing general partner under circumstances where cause does not exist and no units held by us, including our subsidiary that holds the subordinated units (if any) and our other affiliates, are voted in favor of that removal:

- the subordination period will end and all outstanding subordinated units will immediately convert into common units on a one-for-one basis; and

- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished.

If the managing general partner is removed as managing general partner under circumstances where cause does not exist and no units held by the managing general partner and its affiliates (which will include us until such time as we cease to be an affiliate of the managing general partner) are voted in favor of that removal, the managing general partner will have the right to convert its managing general partner interest, including the incentive distribution rights, into common units or to receive cash in exchange for those interests based on the fair market value of the interests at the time.

In the event of removal of the managing general partner under circumstances where cause exists or withdrawal of the managing general partner where that withdrawal violates the partnership

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agreement, a successor managing general partner will have the option to purchase the managing general partner interest, including the IDRs, of the departing managing general partner for a cash payment equal to the fair market value of the managing general partner interest. Under all other circumstances where the managing general partner withdraws or is removed by the limited partners, the departing managing general partner will have the option to require the successor managing general partner to purchase the managing general partner interest of the departing managing general partner for its fair market value. In each case, this fair market value will be determined by agreement between the departing managing general partner and the successor managing general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing managing general partner and the successor managing general partner will determine the fair market value. If the departing managing general partner and the successor managing general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing managing general partner or the successor managing general partner, the departing managing general partner s general partner interest, including its IDRs, will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, the Partnership will be required to reimburse the departing managing general partner for all amounts due to it, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing managing general partner or its affiliates for the Partnership s benefit.

Voting Rights

Various matters require the approval of a unit majority. A unit majority requires (1) prior to the initial offering, the approval of a majority of the special units; (2) during the subordination period, the approval of a majority of the common units, excluding those common units held by the managing general partner and its affiliates (which will include us until such time as we cease to be an affiliate of the managing general partner), and a majority of the sub