CVR ENERGY INC
Form 10-Q
August 07, 2009

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

Form 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2009

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to .

Commission file number: 001-33492

CVR ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**61-1512186**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
2277 Plaza Drive, Suite 500 Sugar Land, Texas	**77479**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code:
(281) 207-3200

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

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

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

Large accelerated filer o Accelerated filer þ Non-accelerated filer o Smaller reporting company o
(Do not check if a smaller reporting company)

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

There were 86,244,245 shares of the registrant s common stock outstanding at August 5, 2009.

CVR ENERGY, INC. AND SUBSIDIARIES

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For The Quarter Ended June 30, 2009

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GLOSSARY OF SELECTED TERMS

The following are definitions of certain industry terms used in this Form 10-Q.

2-1-1 crack spread The approximate gross margin resulting from processing two barrels of crude oil to produce one barrel of gasoline and one barrel of heating oil. The 2-1-1 crack spread is expressed in dollars per barrel.

Ammonia Ammonia is a direct application fertilizer and is primarily used as a building block for other nitrogen products for industrial applications and finished fertilizer products.

Barrel Common unit of measure in the oil industry which equates to 42 gallons.

Blendstocks Various compounds that are combined with gasoline or diesel from the crude oil refining process to make finished gasoline and diesel fuel; these may include natural gasoline, fluid catalytic cracking unit or FCCU gasoline, ethanol, reformate or butane, among others.

bpd Abbreviation for barrels per day.

Bulk sales Volume sales through third party pipelines, in contrast to tanker truck quantity sales.

Capacity Capacity is defined as the throughput a process unit is capable of sustaining, either on a calendar or stream day basis. The throughput may be expressed in terms of maximum sustainable, nameplate or economic capacity. The maximum sustainable or nameplate capacities may not be the most economical. The economic capacity is the throughput that generally provides the greatest economic benefit based on considerations such as feedstock costs, product values and downstream unit constraints.

Catalyst A substance that alters, accelerates, or instigates chemical changes, but is neither produced, consumed nor altered in the process.

Common units The class of interests issued under the limited liability company agreements governing Coffeyville Acquisition LLC, Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC, which provide for voting rights and have rights with respect to profits and losses of, and distributions from, the respective limited liability companies.

Contango markets Markets that are characterized by prices for future delivery that are higher than the current or spot price of the commodity.

Crack spread A simplified calculation that measures the difference between the price for light products and crude oil. For example, the 2-1-1 crack spread is often referenced and represents the approximate gross margin resulting from processing two barrels of crude oil to produce one barrel of gasoline and one barrel of diesel fuel.

Distillates Primarily diesel fuel, kerosene and jet fuel.

Farm belt Refers to the states of Illinois, Indiana, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Texas and Wisconsin.

Feedstocks Petroleum products, such as crude oil and natural gas liquids, that are processed and blended into refined products.

Heavy crude oil A relatively inexpensive crude oil characterized by high relative density and viscosity. Heavy crude oils require greater levels of processing to produce high value products such as gasoline and diesel fuel.

Independent petroleum refiner A refiner that does not have crude oil exploration or production operations. An independent refiner purchases the crude oil used as feedstock in its refinery operations from third parties.

Light crude oil A relatively expensive crude oil characterized by low relative density and viscosity. Light crude oils require lower levels of processing to produce high value products such as gasoline and diesel fuel.

Magellan Magellan Midstream Partners L.P., a publicly traded company whose business is the transportation, storage and distribution of refined petroleum products.

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MMBtu One million British thermal units: a measure of energy. One Btu of heat is required to raise the temperature of one pound of water one degree Fahrenheit.

Natural gas liquids Natural gas liquids, often referred to as NGLs, are feedstocks used in the manufacture of refined fuels. Common NGLs used include propane, isobutane, normal butane and natural gasoline.

PADD II Midwest Petroleum Area for Defense District, which includes Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee and Wisconsin.

Petroleum coke (Pet coke) A coal-like substance that is produced during the refining process.

Refined products Petroleum products, such as gasoline, diesel fuel and jet fuel, that are produced by a refinery.

Sour crude oil A crude oil that is relatively high in sulfur content, requiring additional processing to remove the sulfur. Sour crude oil is typically less expensive than sweet crude oil.

Sweet crude oil A crude oil that is relatively low in sulfur content, requiring less processing to remove the sulfur. Sweet crude oil is typically more expensive than sour crude oil.

Throughput The volume processed through a unit or a refinery.

Turnaround A periodically required standard procedure to refurbish and maintain a refinery that involves the shutdown and inspection of major processing units and occurs every three to four years.

UAN UAN is a solution of urea and ammonium nitrate in water used as a fertilizer.

WTI West Texas Intermediate crude oil, a light, sweet crude oil, characterized by an American Petroleum Institute gravity, or API gravity, between 39 and 41 and a sulfur content of approximately 0.4 weight percent that is used as a benchmark for other crude oils.

WTS West Texas Sour crude oil, a relatively light, sour crude oil characterized by an API gravity of 30-32 degrees and a sulfur content of approximately 2.0 weight percent.

Yield The percentage of refined products that is produced from crude and other feedstocks.

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PART I. FINANCIAL INFORMATION

ITEM 1. *FINANCIAL STATEMENTS*

CVR ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2009 (unaudited)	December 31, 2008
	(in thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 73,341	$ 8,923
Restricted cash		34,560
Accounts receivable, net of allowance for doubtful accounts of $4,250 and $4,128, respectively	68,187	33,316
Inventories	222,740	148,424
Prepaid expenses and other current assets	20,757	37,583
Receivable from swap counterparty	912	32,630
Insurance receivable		11,756
Income tax receivable	6,351	40,854
Deferred income taxes	31,581	25,365
Total current assets	423,869	373,411
Property, plant, and equipment, net of accumulated depreciation	1,156,808	1,178,965
Intangible assets, net	394	410
Goodwill	40,969	40,969
Deferred financing costs, net	2,583	3,883
Receivable from swap counterparty		5,632
Insurance receivable	1,000	1,000
Other long-term assets	3,165	6,213
Total assets	$ 1,628,788	$ 1,610,483
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 4,801	$ 4,825
Note payable and capital lease obligation	4,127	11,543
Payable to swap counterparty	2,701	62,375
Accounts payable	95,873	105,861
Personnel accruals	20,943	10,350

Accrued taxes other than income taxes	16,665	13,841
Deferred revenue	2,808	5,748
Other current liabilities	28,611	30,366
Total current liabilities	176,529	244,909
Long-term liabilities:		
Long-term debt, net of current portion	477,109	479,503
Accrued environmental liabilities, net of current portion	3,537	4,240
Deferred income taxes	299,361	289,150
Other long-term liabilities	3,874	2,614
Total long-term liabilities	783,881	775,507
Commitments and contingencies		
Equity:		
CVR stockholders equity:		
Common Stock $0.01 par value per share, 350,000,000 shares authorized, 86,244,245 and 86,243,745 shares issued and outstanding, respectively	862	862
Additional paid-in-capital	446,151	441,170
Retained earnings	210,765	137,435
Total CVR stockholders equity	657,778	579,467
Noncontrolling interest in subsidiary	10,600	10,600
Total equity	668,378	590,067
Total liabilities and equity	$ 1,628,788	$ 1,610,483

See accompanying notes to the condensed consolidated financial statements.

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CVR ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(unaudited) (in thousands, except share data)			
Net sales	$ 793,304	$ 1,512,503	$ 1,402,699	$ 2,735,506
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	587,635	1,287,477	1,009,240	2,323,671
Direct operating expenses (exclusive of depreciation and amortization)	54,447	62,336	110,681	122,892
Selling, general and administrative expenses (exclusive of depreciation and amortization)	21,772	14,762	41,278	28,259
Net costs associated with flood	(101)	3,896	80	9,659
Depreciation and amortization	21,107	21,080	42,016	40,715
Total operating costs and expenses	684,860	1,389,551	1,203,295	2,525,196
Operating income	108,444	122,952	199,404	210,310
Other income (expense):				
Interest expense and other financing costs	(11,191)	(9,460)	(22,661)	(20,758)
Interest income	653	601	667	1,303
Gain (loss) on derivatives, net	(29,233)	(79,305)	(66,094)	(127,176)
Loss on extinguishment of debt	(677)		(677)	
Other income, net	173	251	198	430
Total other income (expense)	(40,275)	(87,913)	(88,567)	(146,201)
Income before income tax expense	68,169	35,039	110,837	64,109
Income tax expense	25,500	4,051	37,507	10,900
Net income	$ 42,669	$ 30,988	$ 73,330	$ 53,209
Basic earnings per share	$ 0.49	$ 0.36	$ 0.85	$ 0.62
Diluted earnings per share	$ 0.49	$ 0.36	$ 0.85	$ 0.62
Weighted average common shares outstanding:				
Basic	86,244,152	86,141,291	86,243,949	86,141,291
Diluted	86,333,349	86,158,791	86,327,911	86,158,791

See accompanying notes to the condensed consolidated financial statements.

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CVR ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(unaudited) (in thousands)	
Cash flows from operating activities:		
Net income	$ 73,330	$ 53,209
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	42,016	40,715
Provision for doubtful accounts	122	3,937
Amortization of deferred financing costs	1,077	989
Loss on disposition of fixed assets	19	1,550
Loss on extinguishment of debt	677	
Share-based compensation	9,479	(11,123)
Write-off of CVR Partners, L.P. initial public offering costs		2,560
Changes in assets and liabilities:		
Restricted cash	34,560	
Accounts receivable	(34,993)	(54,527)
Inventories	(74,316)	(71,838)
Prepaid expenses and other current assets	9,016	801
Insurance receivable		2,846
Insurance proceeds from flood	11,756	1,500
Other long-term assets	2,805	(2,873)
Accounts payable	(5,032)	(4,666)
Accrued income taxes	34,503	(4,304)
Deferred revenue	(2,940)	(6,166)
Other current liabilities	7,164	4,839
Payable to swap counterparty	(22,324)	67,661
Accrued environmental liabilities	(703)	(223)
Other long-term liabilities	1,260	444
Deferred income taxes	3,995	(2,013)
Net cash provided by operating activities	91,471	23,318
Cash flows from investing activities:		
Capital expenditures	(24,575)	(49,635)
Net cash used in investing activities	(24,575)	(49,635)
Cash flows from financing activities:		
Revolving debt payments	(72,200)	(288,000)
Revolving debt borrowings	72,200	309,500
Principal payments on long-term debt	(2,418)	(2,443)

Payment of capital lease obligation	(60)	(900)
Deferred costs of CVR Partners, L.P. initial public offering		(1,712)
Deferred costs of CVR Energy, Inc. convertible debt offering		(21)
Net cash (used in) provided by financing activities	(2,478)	16,424
Net increase (decrease) in cash and cash equivalents	64,418	(9,893)
Cash and cash equivalents, beginning of period	8,923	30,509
Cash and cash equivalents, end of period	$ 73,341	$ 20,616
Supplemental disclosures:		
Cash paid for income taxes, net of refunds (received)	$ (990)	$ 17,216
Cash paid for interest, net of capitalized interest of $802 and $1,321 in 2009 and 2008, respectively	19,642	20,844
Non-cash investing and financing activities:		
Accrual of construction in progress additions	(4,956)	(14,924)
Assets acquired through capital lease		5,097

See accompanying notes to the condensed consolidated financial statements.

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CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2009
(unaudited)

(1) Organization and History of the Company and Basis of Presentation

Organization

The Company or CVR may be used to refer to CVR Energy, Inc. and, unless the context otherwise requires, its subsidiaries. Any references to the Company as of a date prior to October 16, 2007 (the date of the restructuring as further discussed in this Note) and subsequent to June 24, 2005 are to Coffeyville Acquisition LLC (CALLC) and its subsidiaries.

The Company, through its wholly-owned subsidiaries, acts as an independent petroleum refiner and marketer in the mid-continental United States. In addition, the Company, through its majority-owned subsidiaries, acts as an independent producer and marketer of upgraded nitrogen fertilizer products in North America. The Company s operations include two business segments: the petroleum segment and the nitrogen fertilizer segment.

CALLC formed CVR Energy, Inc. as a wholly-owned subsidiary, incorporated in Delaware in September 2006, in order to effect an initial public offering. The initial public offering of CVR was consummated on October 26, 2007. In conjunction with the initial public offering, a restructuring occurred in which CVR became a direct or indirect owner of all of the subsidiaries of CALLC. Additionally, in connection with the initial public offering, CALLC was split into two entities: CALLC and Coffeyville Acquisition II LLC (CALLC II).

CVR is a controlled company under the rules and regulations of the New York Stock Exchange where its shares are traded under the symbol CVI. As of June 30, 2009, approximately 73% of its outstanding shares were beneficially owned by GS Capital Partners V, L.P. and related entities (GS or Goldman Sachs Funds) and Kelso Investment Associates VII, L.P. and related entities (Kelso or Kelso Funds).

Nitrogen Fertilizer Limited Partnership

In conjunction with the consummation of CVR s initial public offering in 2007, CVR transferred Coffeyville Resources Nitrogen Fertilizer, LLC (CRNF), its nitrogen fertilizer business, to a newly created limited partnership, CVR Partners, LP (the Partnership), in exchange for a managing general partner interest (managing GP interest), a special general partner interest (special GP interest, represented by special GP units) and a de minimis limited partner interest (LP interest, represented by special LP units). This transfer was not considered a business combination as it was a transfer of assets among entities under common control and, accordingly, balances were transferred at their historical cost. CVR concurrently sold the managing GP interest to Coffeyville Acquisition III LLC (CALLC III) an entity owned by its controlling stockholders and senior management, at fair market value. The board of directors of CVR determined, after consultation with management, that the fair market value of the managing GP interest was $10,600,000. This interest has been classified as a noncontrolling interest included as a separate component of equity in the Consolidated Balance Sheets at June 30, 2009 and December 31, 2008.

CVR owns all of the interests in the Partnership (other than the managing GP interest and the associated incentive distribution rights (IDRs)) and is entitled to all cash distributed by the Partnership except with respect to IDRs. The managing general partner is not entitled to participate in Partnership distributions except with respect to its IDRs, which entitle the managing general partner to receive increasing percentages (up to 48%) of the cash the Partnership distributes in excess of $0.4313 per unit in a quarter. However, the Partnership is not permitted to make any distributions with respect to the IDRs until the aggregate Adjusted Operating Surplus, as defined in the Partnership s partnership agreement, generated by the Partnership through December 31, 2009, has been distributed in respect of the units held by CVR and any common units issued by the Partnership if it elects to pursue an initial public offering. In addition, the Partnership and its subsidiaries are currently guarantors under the credit facility of Coffeyville Resources, LLC (CRLLC), a wholly-owned subsidiary of CVR. There will be no distributions paid with respect to the IDRs for so long as the Partnership or its subsidiaries are guarantors under the credit facility.

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CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Partnership is operated by CVR s senior management pursuant to a services agreement among CVR, the managing general partner, and the Partnership. The Partnership is managed by the managing general partner and, to the extent described below, CVR, as special general partner. As special general partner of the Partnership, CVR has joint management rights regarding the appointment, termination, and compensation of the chief executive officer and chief financial officer of the managing general partner, has the right to designate two members of the board of directors of the managing general partner, and has joint management rights regarding specified major business decisions relating to the Partnership. CVR, the Partnership, and the managing general partner also entered into a number of agreements to regulate certain business relations between the parties.

At June 30, 2009, the Partnership had 30,333 special LP units outstanding, representing 0.1% of the total Partnership units outstanding, and 30,303,000 special GP interests outstanding, representing 99.9% of the total Partnership units outstanding. In addition, the managing general partner owned the managing GP interest and the IDRs. The managing general partner contributed 1% of CRNF s interest to the Partnership in exchange for its managing GP interest and the IDRs.

In accordance with the Contribution, Conveyance, and Assumption Agreement, by and between the Partnership and the partners, dated as of October 24, 2007, if an initial private or public offering of the Partnership is not consummated by October 24, 2009, the managing general partner of the Partnership can require the Company to purchase the managing GP interest. This put right expires on the earlier of (1) October 24, 2012 or (2) the closing of the Partnership s initial private or public offering. If the Partnership s initial private or public offering is not consummated by October 24, 2012, the Company has the right to require the managing general partner to sell the managing GP interest to the Company. This call right expires on the closing of the Partnership s initial private or public 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 GP interest at the time of the purchase determined by an independent investment banking firm selected by the Company and the managing general partner.

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements were prepared in accordance with U.S. generally accepted accounting principles (GAAP) and in accordance with the rules and regulations of the Securities and Exchange Commission (SEC). The consolidated financial statements include the accounts of CVR and its majority-owned direct and indirect subsidiaries. The ownership interests of noncontrolling investors in its subsidiaries are classified as a noncontrolling interest included as a separate component of equity for all periods presented. All intercompany account balances and transactions have been eliminated in consolidation. Certain information and footnotes required for complete financial statements under GAAP have been condensed or omitted pursuant to SEC rules and regulations. These unaudited condensed consolidated financial statements should be read in conjunction with the December 31, 2008 audited consolidated financial statements and notes thereto included in CVR s Annual Report on Form 10-K for the year ended December 31, 2008, which was filed with the SEC on March 13, 2009.

In the opinion of the Company s management, the accompanying unaudited condensed consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments) that are necessary to fairly present the financial position of the Company as of June 30, 2009 and December 31, 2008, the results of operations for the three months and six months ended June 30, 2009 and 2008, and the cash flows for the six months ended June 30, 2009 and 2008.

Results of operations and cash flows for the interim periods presented are not necessarily indicative of the results that will be realized for the year ending December 31, 2009 or any other interim period. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

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CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As a result of the adoption of Statement of Financial Accounting Standards (SFAS) No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51,* on January 1, 2009, the noncontrolling interest for the year ended December 31, 2008 has been properly reclassified to be included in the Company s equity section of the Consolidated Balance Sheets.

As a result of the adoption of SFAS No. 165, *Subsequent Events*, on June 15, 2009, the Company evaluated subsequent events, if any, that would require an adjustment to the Company s financial statements or require disclosure in the notes to the financial statements. The Company has evaluated subsequent events through August 7, 2009, the date of issuance of the condensed consolidated financial statements. (See Note 16 (Subsequent Events) for discussion.)

(2) Recent Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board (FASB) issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)*. SFAS 167 is intended to improve financial reporting by enterprises involved with variable interest entities. SFAS 167 is effective as of the beginning of the entity s first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period, and for interim and annual reporting periods thereafter. The Company is currently evaluating the impact of the standard, but does not believe it will have a material impact on the Company s financial position or results of operations.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*, which became effective June 15, 2009 and is to be applied to all interim and annual financial periods ending thereafter. SFAS 165 is intended to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which the Company has evaluated subsequent events and the basis for that date that is, whether that date represents the date the financial statements were issued or were available to be issued. As required, the Company adopted this statement as of June 15, 2009. As a result of this adoption, the Company provided additional disclosures regarding the evaluation of subsequent events and the date through which that evaluation took place. There is no impact on the financial position or results of operations of the Company as a result of this adoption.

In April 2009, the FASB issued FASB Staff Position (FSP) No. 157-4, *Determining Fair Value when the Volume and Level of Activity for the Asset or Liability have Significantly Decreased and Identifying Transactions That Are Not Orderly*. The FSP provides guidance for determining the fair value of an asset or liability when there has been a significant decrease in market activity. In addition, the FSP requires additional disclosures regarding the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, during annual or interim periods. As required, the Company adopted this statement as of June 15, 2009. Based upon the Company s assets and liabilities currently subject to the provisions of SFAS No. 157, *Fair Value Measurements*, there is no impact on the Company s financial position, results of operations or disclosures as a result of this adoption.

In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, which became effective January 1, 2009 and is to be applied retrospectively. Under the FSP, unvested share-based payment awards, which receive non-forfeitable dividend rights or dividend equivalents, are considered participating securities and are now required to be included in computing earnings per share under the two class method. As required, the Company adopted this statement as of January 1, 2009. Based upon the nature of the Company s share-based payment awards, it has been determined that these awards are not participating securities and, therefore, the FSP currently has no impact on the Company s earnings per share calculations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133.* This statement changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about how and

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedge items affect an entity s financial position, net earnings, and cash flows. As required, the Company adopted this statement as of January 1, 2009. As a result of the adoption, the Company provided additional disclosures regarding its derivative instruments in the notes to the condensed consolidated financial statements. There is no impact on the financial position or results of operations of the Company as a result of this adoption.

In February 2008, the FASB issued FSP No. 157-2 which defers the effective date of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in an entity s financial statements on a recurring basis (at least annually). As required, the Company adopted SFAS 157 as of January 1, 2009. The adoption of SFAS 157 did not impact the Company s financial position or results of operations.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51.* SFAS 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing noncontrolling interests. All other requirements of SFAS 160 must be applied prospectively. The Company adopted SFAS 160 effective January 1, 2009, and as a result has classified the noncontrolling interest (previously minority interest) as a separate component of equity for all periods presented.

(3) Share-Based Compensation

Prior to CVR s initial public offering in October 2007, CVR s subsidiaries were held and operated by CALLC, a limited liability company. Management of CVR holds an equity interest in CALLC. CALLC issued non-voting override units to certain management members who held common units of CALLC. There were no required capital contributions for the override operating units. In connection with CVR s initial public offering, CALLC was split into two entities: CALLC and CALLC II. In connection with this split, management s equity interest in CALLC, including both their common units and non-voting override units, was split so that half of management s equity interest was in CALLC and half was in CALLC II. CALLC was historically the primary reporting company and CVR s predecessor. In addition, in connection with the transfer of the managing GP interest of the Partnership to CALLC III in October 2007, CALLC III issued non-voting override units to certain management members of CALLC III.

CVR, CALLC, CALLC II and CALLC III account for share-based compensation in accordance with SFAS No. 123(R), *Share-Based Payments,* and EITF Issue No. 00-12, *Accounting by an Investor for Stock-Based Compensation Granted to Employees of an Equity Method Investee*. CVR has been allocated non-cash share-based compensation expense from CALLC, CALLC II and CALLC III.

In accordance with SFAS 123(R), CVR, CALLC, CALLC II and CALLC III apply a fair-value based measurement method in accounting for share-based compensation. In accordance with EITF 00-12, CVR recognizes the costs of the share-based compensation incurred by CALLC, CALLC II and CALLC III on its behalf, primarily in selling, general, and administrative expenses (exclusive of depreciation and amortization), and a corresponding capital contribution, as the costs are incurred on its behalf, following the guidance in EITF Issue No. 96-18, *Accounting for Equity Investments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling Goods or*

Services, which requires remeasurement at each reporting period through the performance commitment period, or in CVR s case, through the vesting period.

At June 30, 2009, the value of the override units of CALLC and CALLC II was derived from a probability-weighted expected return method. The probability-weighted expected return method involves a forward-looking analysis of possible future outcomes, the estimation of ranges of future and present value under each outcome, and

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the application of a probability factor to each outcome in conjunction with the application of the current value of the Company s common stock price with a Black-Scholes option pricing formula, as remeasured at each reporting date until the awards are vested.

The estimated fair value of the override units of CALLC III has been determined using a probability-weighted expected return method which utilizes CALLC III s cash flow projections, which are representative of the nature of interests held by CALLC III in the Partnership.

The following table provides key information for the share-based compensation plans related to the override units of CALLC, CALLC II, and CALLC III. Compensation expense amounts are disclosed in thousands.

				*Compensation Expense Increase (Decrease) for the Three Months Ended June 30,_		*Compensation Expense Increase (Decrease) for the Six Months Ended June 30,	
Award Type	**Benchmark Value (per Unit)**	**Awards Issued**	**Grant Date**	**2009**	**2008**	**2009**	**2008**
Override Operating Units(a)	$ 11.31	919,630	June 2005	$ 904	$ (3,967)	$ 1,487	$ (4,525)
Override Operating Units(b)	$ 34.72	72,492	December 2006	28	(261)	51	(255)
Override Value Units(c)	$ 11.31	1,839,265	June 2005	1,901	(3,731)	3,089	(3,198)
Override Value Units(d)	$ 34.72	144,966	December 2006	73	(165)	135	(74)
Override Units(e)	$ 10.00	138,281	October 2007		(2)		(2)
Override Units(f)	$ 10.00	642,219	February 2008	3	1	4	2
			Total	$ 2,909	$ (8,125)	$ 4,766	$ (8,052)

* As CVR s common stock price increases or decreases, compensation expense increases or is reversed in correlation with the calculation of the fair value under the probability-weighted expected return method.

Valuation Assumptions

Significant assumptions used in the valuation of the Override Operating Units (a) and (b) were as follows:

	(a) Override Operating Units June 30, 2009	2008	(b) Override Operating Units June 30, 2009	2008
Estimated forfeiture rate	None	None	None	None
CVR closing stock price	$7.33	$19.25	$7.33	$19.25
Estimated fair value	$14.27 per unit	$40.05 per unit	$3.57 per unit	$20.86 per unit
Marketability and minority interest discounts	20% discount	15% discount	20% discount	15% discount
Volatility	59.3%	N/A	59.3%	N/A

On the tenth anniversary of the issuance of override operating units, such units convert into an equivalent number of override value units. Override operating units are forfeited upon termination of employment for cause. The explicit service period for override operating unit recipients is based on the forfeiture schedule below. In the

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event of all other terminations of employment, the override operating units are initially subject to forfeiture as follows:

Minimum Period Held	Forfeiture Percentage
2 years	75%
3 years	50%
4 years	25%
5 years	0%

Significant assumptions used in the valuation of the Override Value Units (c) and (d) were as follows:

	(c) Override Value Units June 30,		(d) Override Value Units June 30,	
	2009	2008	2009	2008
Estimated forfeiture rate	None	None	None	None
Derived service period	6 years	6 years	6 years	6 years
CVR closing stock price	$7.33	$19.25	$7.33	$19.25
Estimated fair value	$7.69 per unit	$40.05 per unit	$3.57 per unit	$20.86 per unit
Marketability and minority interest discounts	20% discount	15% discount	20% discount	15% discount
Volatility	59.3%	N/A	59.3%	N/A

Unless the compensation committee of the board of directors of CVR takes an action to prevent forfeiture, override value units are forfeited upon termination of employment for any reason, except that in the event of termination of employment by reason of death or disability, all override value units are initially subject to forfeiture as follows:

Minimum Period Held	Forfeiture Percentage
2 years	75%
3 years	50%
4 years	25%
5 years	0%

(e) *Override Units* In accordance with SFAS 123(R), using a binomial and a probability-weighted expected return method which utilized CALLC III s cash flows projections which includes expected future earnings and the anticipated timing of IDRs, the estimated grant date fair value of the override units was approximately $3,000. In accordance with EITF 00-12, as a non-contributing investor, CVR also recognized income equal to the amount that its interest in the investee s net book value has increased (that is its percentage share of the contributed capital recognized by the investee) as a result of the disproportionate funding of the compensation cost. As of June 30, 2009 these units were fully vested. Significant assumptions used in the valuation were as follows:

Estimated forfeiture rate	None
Grant date valuation	$0.02 per unit
Marketability and minority interest discount	15% discount
Volatility	34.7%

(f) *Override Units* In accordance with SFAS 123(R), using a probability-weighted expected return method which utilized CALLC III s cash flows projections which includes expected future earnings and the anticipated

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timing of IDRs, the estimated grant date fair value of the override units was approximately $3,000. In accordance with EITF 00-12, as a non-contributing investor, CVR also recognized income equal to the amount that its interest in the investee s net book value has increased (that is its percentage share of the contributed capital recognized by the investee) as a result of the disproportionate funding of the compensation cost. Of the 642,219 units issued, 109,720 were immediately vested upon issuance and the remaining units are subject to a forfeiture schedule. Significant assumptions used in the valuation were as follows:

	June 30, 2009	June 30, 2008
Estimated forfeiture rate	None	None
Derived Service Period	Based on forfeiture schedule	Based on forfeiture schedule
Estimated fair value	$0.03 per unit	$0.007 per unit
Marketability and minority interest discount	20% discount	15% discount
Volatility	47.0%	36.2%

At June 30, 2009, assuming no change in the estimated fair value at June 30, 2009, there was approximately $5,144,000 of unrecognized compensation expense related to non-voting override units. This expense is expected to be recognized over a remaining period of approximately three years as follows (in thousands):

	Override Operating Units	Override Value Units
Six months ending December 31, 2009	$ 314	$ 1,154
Year ending December 31, 2010	297	2,288
Year ending December 31, 2011		1,091
	$ 611	$ 4,533

Phantom Unit Plans

CVR, through a wholly-owned subsidiary, has two Phantom Unit Appreciation Plans (the Phantom Unit Plans) whereby directors, employees, and service providers may be awarded phantom points at the discretion of the board of directors or the compensation committee. Holders of service phantom points have rights to receive distributions when holders of override operating units receive distributions. Holders of performance phantom points have rights to receive distributions when holders of override value units receive distributions. There are no other rights or guarantees, and the plan expires on July 25, 2015 or at the discretion of the compensation committee of the board of directors. As of June 30, 2009, the issued Profits Interest (combined phantom points and override units) represented 15% of combined common unit interest and Profits Interest of CALLC and CALLC II. The Profits Interest was comprised of approximately 11.1% of override interest and approximately 3.9% of phantom interest. In accordance with SFAS 123(R), the expense associated with these awards for 2009 is based on the current fair value of the awards which was derived from a probability-weighted expected return method. The probability-weighted expected return method involves a forward-looking analysis of possible future outcomes, the estimation of ranges of future and present value under each outcome, and the application of a probability factor to each outcome in conjunction with the application of the current value of the Company s common stock price with a Black-Scholes option pricing formula, as remeasured at each reporting date until the awards are settled. Based upon this methodology, the service phantom interest and performance phantom interest were valued at $14.27 and $7.69 per point, respectively, at June 30, 2009. In accordance with SFAS 123(R), using the June 30, 2008 CVR stock closing price to determine the Company s equity value, through an independent valuation process, the service phantom interest and performance phantom interest were both valued at $40.05 per point. CVR has recorded approximately $8,381,000 and $3,882,000 in personnel accruals as of June 30, 2009 and December 31, 2008, respectively.

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Compensation expense for the three months ended June 30, 2009 and 2008 related to the Phantom Unit Plans was $2,603,000 and reversed by $(2,709,000), respectively. Compensation expense related to the Phantom Unit Plan for the six months ended June 30, 2009 and 2008 was $4,498,000 and $(3,256,000), respectively.

At June 30, 2009, assuming no change in the estimated fair value at June 30, 2009, there was approximately $1,832,000 of unrecognized compensation expense related to the Phantom Unit Plans. This is expected to be recognized over a remaining period of approximately two years.

Long Term Incentive Plan

CVR has a Long Term Incentive Plan (LTIP) which permits the grant of options, stock appreciation rights, or SARS, non-vested shares, non-vested share units, dividend equivalent rights, share awards and performance awards (including performance share units, performance units and performance based restricted stock).

Stock Options

As of June 30, 2009, there have been a total of 32,350 stock options granted, of which 7,750 have vested as of June 30, 2009. As of December 31, 2008, 6,300 options were vested and an additional 1,450 vested in the second quarter of 2009. There were no additional grants or forfeitures of stock options for the six months ended June 30, 2009. As of June 30, 2009, there was approximately $107,000 of total unrecognized compensation cost related to stock options to be recognized over a weighted-average period of approximately two years.

Non-Vested Stock

A summary of non-vested stock grant activity and changes during the six months ended June 30, 2009 is presented below:

Non-Vested Stock	**Grants**	**Weighted-Average Grant-Date Fair Value**
Outstanding at January 1, 2009 (non-vested)	78,666	$ 6.62
Vesting and transfer of ownership to recipients	(500)	4.14
Granted	25,000	7.59
Forfeited	(3,100)	4.14
Outstanding at June 30, 2009 (non-vested)	100,066	$ 6.95

Through the LTIP, shares of non-vested stock have been granted to employees and directors of the Company. These shares generally vest over a three-year period. Although ownership of the shares does not transfer to the recipients until the shares have vested, recipients have voting and dividend rights on these shares from the date of grant. As of

June 30, 2009, there was approximately $425,000 of total unrecognized compensation cost related to non-vested shares to be recognized over a weighted-average period of approximately two and one-half years.

Compensation expense recorded for the three months ended June 30, 2009 and 2008 related to the non-vested stock and stock options was $113,000 and $94,000, respectively. Compensation expense recorded for the six months ended June 30, 2009 and 2008 related to non-vested stock and stock options was $215,000 and $185,000, respectively.

(4) Inventories

Inventories consist primarily of crude oil, blending stock and components, work in progress, fertilizer products, and refined fuels and by-products. Inventories are valued at the lower of the first-in, first-out (FIFO) cost or market for fertilizer products, refined fuels and by-products for all periods presented. Refinery unfinished

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and finished products inventory values were determined using the ability-to-bear process, whereby raw materials and production costs are allocated to work-in-process and finished products based on their relative fair values. Other inventories, including other raw materials, spare parts, and supplies, are valued at the lower of moving-average cost, which approximates FIFO, or market. The cost of inventories includes inbound freight costs.

Inventories consisted of the following (in thousands):

	June 30, 2009	December 31, 2008
Finished goods	$ 99,761	$ 61,008
Raw materials and catalysts	84,408	45,928
In-process inventories	12,148	14,376
Parts and supplies	26,423	27,112
	$ 222,740	$ 148,424

(5) Property, Plant, and Equipment

A summary of costs for property, plant, and equipment is as follows (in thousands):

	June 30, 2009	December 31, 2008
Land and improvements	$ 17,451	$ 17,383
Buildings	23,104	22,851
Machinery and equipment	1,301,722	1,288,782
Automotive equipment	8,866	7,825
Furniture and fixtures	7,937	7,835
Leasehold improvements	1,081	1,081
Construction in progress	59,052	53,927
	1,419,213	1,399,684
Accumulated depreciation	262,405	220,719
	$ 1,156,808	$ 1,178,965

Capitalized interest recognized as a reduction in interest expense for the three months ended June 30, 2009 and June 30, 2008 totaled approximately $389,000 and $203,000, respectively. Capitalized interest for the six months ended June 30, 2009 and 2008 totaled approximately $802,000 and $1,321,000, respectively. Land and buildings that are under a capital lease obligation approximated $4,827,000 as of June 30, 2009 and December 31, 2008. Amortization of assets held under capital leases is included in depreciation expense.

(6) Cost Classifications

Cost of product sold (exclusive of depreciation and amortization) includes cost of crude oil, other feedstocks, blendstocks, pet coke expense and freight and distribution expenses. Cost of product sold excludes depreciation and amortization of $719,000 and $611,000 for the three months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009 and 2008, cost of product sold excludes depreciation and amortization of $1,430,000 and $1,210,000, respectively.

Direct operating expenses (exclusive of depreciation and amortization) includes direct costs of labor, maintenance and services, energy and utility costs, as well as chemicals and catalysts and other direct operating expenses. Direct operating expenses excludes depreciation and amortization of $19,922,000 and $20,108,000 for

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the three months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009 and 2008, direct operating expenses exclude depreciation and amortization of $39,664,000 and $38,811,000, respectively.

Selling, general and administrative expenses (exclusive of depreciation and amortization) consist primarily of legal expenses, treasury, accounting, marketing, human resources and maintaining the corporate office in Texas and the administrative office in Kansas. Selling, general and administrative expenses excludes depreciation and amortization of $466,000 and $361,000 for the three months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009 and 2008, selling, general and administrative expenses exclude depreciation and amortization of $922,000 and $694,000, respectively.

(7) Note Payable and Capital Lease Obligation

The Company entered into an insurance premium finance agreement with Cananwill, Inc. in July 2008 to finance a portion of the purchase of its property, liability, cargo and terrorism policies. The original balance of the note provided by the Company under such agreement was $10,000,000. As of December 31, 2008, the Company owed $7,500,000 related to this note. This note was repaid in equal installments with the final payment due in June 2009. As of June 30, 2009, the Company repaid the entire note obligation.

The Company also entered into a capital lease for real property used for corporate purposes on May 29, 2008. The lease had an initial lease term of one year with an option to renew for three additional one-year periods. During the second quarter of 2009, the Company renewed the lease for a one-year period commencing June 5, 2009. Quarterly lease payments made in connection with this capital lease total $80,000 annually. The Company also has the option to purchase the property during the term of the lease, including the renewal periods. In connection with the capital lease the Company recorded a capital asset and capital lease obligation of $4,827,000. The capital lease obligation was $4,127,000 and $4,043,000 as of June 30, 2009 and December 31, 2008, respectively.

(8) Flood, Crude Oil Discharge and Insurance Related Matters

For the three months ended June 30, 2009 and 2008, the Company recorded pretax expenses, net of anticipated insurance recoveries of $(101,000) and $3,896,000, respectively, associated with the June/July 2007 flood and associated crude oil discharge. For the six months ended June 30, 2009 and 2008, the Company recorded pretax expenses, net of anticipated insurance recoveries of $80,000 and $9,659,000, respectively, associated with the June/July 2007 flood and associated crude oil discharge. The costs are reported in net costs associated with flood in the Consolidated Statements of Operations. Total accounts receivable from insurance was $1,000,000 at June 30, 2009 and $12,756,000 as of December 31, 2008. With the final insurance proceeds received under the Company s property insurance policy and builders risk policy during the first quarter of 2009, in the amount of $11,756,000, all property insurance claims and builders risk claims were fully settled with all remaining claims closed. The receivable balance at June 30, 2009 is associated with the crude oil discharge. See Note 11 (Commitments and Contingent Liabilities) for additional information regarding environmental and other contingencies related to the crude oil discharge that occurred on July 1, 2007.

As of June 30, 2009, the remaining receivable from insurers was not anticipated to be collected in the next twelve months, and therefore has been classified as a non-current asset. Management believes the recovery of the receivable from the insurance carriers is probable.

(9) Income Taxes

As of June 30, 2009, the Company did not have any unrecognized tax benefits and did not have an accrual for any amounts for interest or penalties related to uncertain tax positions. The Company s accounting policy with respect to interest and penalties related to tax uncertainties is to classify these amounts as income taxes.

CVR and its subsidiaries file U.S. federal and various state income and franchise tax returns. The Company s U.S. federal and state tax years subject to examination as of June 30, 2009 are 2005 to 2008.

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The Company s effective tax rate for the three and six months ended June 30, 2009 were 37.4% and 33.8%, respectively, as compared to the Company s combined federal and state expected statutory tax rate of 39.7%. For the same periods in 2008, the effective tax rates were 11.6% and 17.0%, respectively. The effective tax rate is lower than the expected statutory tax rate for the three and six months ended June 30, 2009 and 2008, respectively, due primarily to federal income tax credits available to small business refiners related to the production of ultra low sulfur diesel fuel. Additionally, the effective tax rate for 2008 was favorably impacted by Kansas state income tax incentives generated under the High Performance Incentive Program.

(10) Earnings Per Share

Basic and diluted earnings per share are computed by dividing net income by weighted average common shares outstanding. The components of the basic and diluted earnings per share calculation are as follows:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands, except share data)			
Net income	$ 42,669	$ 30,988	$ 73,330	$ 53,209
Weighted average common shares outstanding	86,244,152	86,141,291	86,243,949	86,141,291
Effect of dilutive securities:				
Non-vested common stock	89,197	17,500	83,962	17,500
Weighted average common shares outstanding assuming dilution	86,333,349	86,158,791	86,327,911	86,158,791
Basic earnings per share	$ 0.49	$ 0.36	$ 0.85	$ 0.62
Diluted earnings per share	$ 0.49	$ 0.36	$ 0.85	$ 0.62

Outstanding stock options totaling 32,350 common shares were excluded from the diluted earnings per share calculation for the three and six months ended June 30, 2009, respectively, as they were antidilutive. Outstanding stock options totaling 23,250 common shares were excluded from the diluted per share calculation for the three and six months ended June 30, 2008, respectively, as they were antidilutive.

(11) Commitments and Contingent Liabilities

Leases and Unconditional Purchase Obligations

The minimum required payments for the Company s lease agreements and unconditional purchase obligations are as follows (in thousands):

	Operating	Unconditional

	Leases	Purchase Obligations(1)
Six months ending December 31, 2009	$ 2,313	$ 15,714
Year ending December 31, 2010	4,352	32,497
Year ending December 31, 2011	2,979	30,975
Year ending December 31, 2012	2,585	28,132
Year ending December 31, 2013	1,692	28,093
Thereafter	422	181,820
	$ 14,343	$ 317,231

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(1) This amount excludes approximately $510,000,000 potentially payable under petroleum transportation service agreements with TransCanada Keystone Pipeline, LP (TransCanada), pursuant to which CRRM would receive a volume amount of at least 25,000 barrels per day with a delivery point at Cushing, Oklahoma for a term of 10 years on a new pipeline system being constructed by TransCanada. This amount would be payable ratably over the 10 year service period under the agreements, such period to begin upon commencement of services under the new pipeline system. Based on information currently available to us, we believe commencement of services would begin in the first quarter of 2011. The Company is currently undertaking action to dispute the validity of the petroleum transportation service agreements. The Company cannot provide any assurance that the petroleum transportation service agreements will be found to be invalid.

The Company leases various equipment, including rail cars, and real properties under long-term operating leases, expiring at various dates. In the normal course of business, the Company also has long-term commitments to purchase services such as natural gas, electricity, water and transportation services. For the three months ended June 30, 2009 and 2008, lease expense totaled $1,292,000 and $1,003,000, respectively. For the six months ended June 30, 2009 and 2008, lease expense totaled $2,481,000 and $2,074,000, respectively. The lease agreements have various remaining terms. Some agreements are renewable, at the Company s option, for additional periods. It is expected, in the ordinary course of business, that leases will be renewed or replaced as they expire. The Company also has other customary operating leases and unconditional purchase obligations primarily related to pipeline, utility and raw material suppliers. These leases and agreements are entered into in the normal course of business.

Litigation

Samson Resources Company, Samson Lone Star, LLC and Samson Contour Energy E&P, LLC (together, Samson) filed 15 lawsuits in federal and state courts in Oklahoma against Coffeyville Resources Refining & Marketing, LLC (CRRM) and other defendants between March 2009 and July 2009. All of the lawsuits allege that Samson sold crude oil to a now bankrupt group of companies, which generally are known as SemCrude or SemGroup (collectively, Sem), and that Sem has not paid Samson for all of the crude oil purchased from Sem. The lawsuits further allege that Sem sold some of the crude oil purchased from Samson to J. Aron & Company and that J. Aron & Company sold some of this crude oil to CRRM. All of the lawsuits seek the same remedy, the imposition of a trust, an accounting and the return of crude oil or the proceeds therefrom. The amount of Samson s alleged claims are unknown since the price and amount of crude oil sold by Samson and eventually received by CRRM through Sem and J. Aron, if any, is unknown. CRRM timely paid for all crude oil purchased from J. Aron & Company and intends to vigourously defend against these claims.

From time to time, the Company is involved in various lawsuits arising in the normal course of business, including matters such as those described below under Environmental, Health, and Safety (EHS) Matters. Liabilities related to such litigation are recognized when the related costs are probable and can be reasonably estimated. Management believes the Company has accrued for losses for which it may ultimately be responsible. It is possible that management s estimates of the outcomes will change within the next year due to uncertainties inherent in litigation and settlement negotiations. In the opinion of management, the ultimate resolution of any other litigation matters is not expected to have a material adverse effect on the accompanying consolidated financial statements. There can be no assurance that management s beliefs or opinions with respect to liability for potential litigation matters are accurate.

Flood, Crude Oil Discharge and Insurance

Crude oil was discharged from the Company s refinery on July 1, 2007 due to the short amount of time available to shut down and secure the refinery in preparation for the flood that occurred on June 30, 2007. In connection with that discharge, the Company received in May 2008 notices of claims from sixteen private claimants under the Oil Pollution Act in an aggregate amount of approximately $4,393,000. In August 2008, those claimants filed suit against the Company in the United States District Court for the District of Kansas in Wichita. The

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company believes that the resolution of these claims will not have a material adverse effect on the consolidated financial statements.

As a result of the crude oil discharge that occurred on July 1, 2007, the Company entered into an administrative order on consent (the Consent Order) with the Environmental Protection Agency (EPA) on July 10, 2007. As set forth in the Consent Order, the EPA concluded that the discharge of oil from the Company s refinery caused an imminent and substantial threat to the public health and welfare. Pursuant to the Consent Order, the Company agreed to perform specified remedial actions to respond to the discharge of crude oil from the Company s refinery. The substantial majority of all known remedial actions were completed by January 31, 2009. The Company prepared its final report to the EPA to satisfy the final requirement of the Consent Order. The Company anticipates that the EPA s review of this report will not result in any further requirements that could be material to the Company s business, financial condition, or results of operations.

As of June 30, 2009, the total gross costs recorded associated with remediation and third party property damage as a result of the crude oil discharge approximated $54,389,000. The Company has not estimated or accrued for any potential fines, penalties or claims that may be imposed or brought by regulatory authorities or possible additional damages arising from lawsuits related to the June/July 2007 flood as management does not believe any such fines, penalties or lawsuits would be material or can be estimated.

The Company is seeking insurance coverage for this release and for the ultimate costs for remediation and property damage claims. On July 10, 2008, the Company filed two lawsuits in the United States District Court for the District of Kansas against certain of the Company s insurance carriers with regard to the Company s insurance coverage for the June/July 2007 flood and crude oil discharge. The Company s excess environmental liability insurance carrier has asserted that the Company s pollution liability claims are for cleanup, which is not covered by such policy, rather than for property damage, which is covered to the limits of the policy. While the Company will vigorously contest the excess carrier s position, it contends that if that position were upheld, the umbrella Comprehensive General Liability policies would continue to provide coverage for these claims. Each insurer, however, has reserved its rights under various policy exclusions and limitations and has cited potential coverage defenses. Although the Company believes that certain amounts under the environmental and liability insurance policies will be recovered, the Company cannot be certain of the ultimate amount or timing of such recovery because of the difficulty inherent in projecting the ultimate resolution of the Company s claims.

The lawsuit with the insurance carriers under the environmental liability and comprehensive general liability policies remains the only unsettled lawsuit with the insurance carriers. The property insurance lawsuit has been settled and dismissed.

Environmental, Health, and Safety (EHS) Matters

CRRM, Coffeyville Resources Crude Transportation, LLC (CRCT) and Coffeyville Resources Terminal, LLC (CRT), all of which are wholly-owned subsidiaries of CVR, and CRNF are subject to various stringent federal, state, and local EHS rules and regulations. Liabilities related to EHS matters are recognized when the related costs are 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 EHS liabilities, no offset is made for potential recoveries. Such liabilities include estimates of the Company s share of costs attributable to potentially responsible parties which are insolvent or otherwise unable to pay. EHS liabilities are monitored and adjusted regularly as new facts emerge or changes in law or technology occur.

CRRM, CRNF, CRCT and CRT own and/or operate manufacturing and ancillary operations at various locations directly related to petroleum refining and distribution and nitrogen fertilizer manufacturing. Therefore, CRRM, CRNF, CRCT and CRT have exposure to potential EHS liabilities related to past and present EHS conditions at some of these locations.

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CRRM and CRT have agreed to perform corrective actions at the Coffeyville, Kansas refinery and Phillipsburg, Kansas terminal facility, pursuant to Administrative Orders on Consent issued under the Resource Conservation and Recovery Act (RCRA) to address historical contamination by the prior owners (RCRA Docket No. VII-94-H-0020 and Docket No. VII-95-H-011, respectively). In 2005, CRNF agreed to participate in the State of Kansas Voluntary Cleanup and Property Redevelopment Program (VCPRP) to address a reported release of UAN at its UAN loading rack. As of June 30, 2009 and December 31, 2008, environmental accruals of $6,099,000 and $6,924,000, respectively, were reflected in the consolidated balance sheets for probable and estimated costs for remediation of environmental contamination under the RCRA Administrative Orders and the VCPRP, including amounts totaling $2,562,000 and $2,684,000, respectively, included in other current liabilities. The Company s accruals were determined based on an estimate of payment costs through 2031, for which the scope of remediation was arranged with the EPA, and were discounted at the appropriate risk free rates at June 30, 2009 and December 31, 2008, respectively. The accruals include estimated closure and post-closure costs of $1,467,000 and $1,124,000 for two landfills at June 30, 2009 and December 31, 2008, respectively. The estimated future payments for these required obligations are as follows (in thousands):

	Amount
Six months ending December 31, 2009	$ 2,055
Year ending December 31, 2010	1,013
Year ending December 31, 2011	516
Year ending December 31, 2012	313
Year ending December 31, 2013	313
Thereafter	2,682
Undiscounted total	6,892
Less amounts representing interest at 3.19%	793
Accrued environmental liabilities at June 30, 2009	$ 6,099

Management periodically reviews and, as appropriate, revises its environmental accruals. Based on current information and regulatory requirements, management believes that the accruals established for environmental expenditures are adequate.

In February 2000, the EPA promulgated the Tier II Motor Vehicle Emission Standards Final Rule for all passenger vehicles, establishing standards for sulfur content in gasoline that were required to be met by 2006. In addition, in January 2001, the 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. In February 2004, the EPA granted the Company approval under a hardship waiver that would defer meeting final Ultra Low Sulfur Gasoline (ULSG) standards and Ultra Low Sulfur Diesel (ULSD) requirements. The hardship waiver was revised at CRRM s request on September 25, 2008. The Company met the conditions of the hardship waiver related to the ULSD requirements in late 2006 and is continuing its work related to meeting its compliance date with ULSG standards in accordance with the revised hardship waiver. Compliance with the Tier II gasoline and on-road diesel standards required us to spend approximately $13,787,000 during 2008, approximately $16,800,000 during 2007 and $79,033,000 during 2006. Based on information currently available, CRRM and CRT anticipate spending approximately $24,486,000 in 2009 and $20,242,000 in 2010 to comply with ULSG requirements. The entire amounts are expected to be capitalized. For the three months ended June 30, 2009 and 2008, CVR has spent $3,633,000 and $6,226,000, respectively. For the six months ended June 30, 2009 and 2008, CVR has spent $7,082,000 and $8,167,000, respectively.

EPA promulgated regulations in 2007 that require the reduction of benzene in gasoline by 2011. CRRM is a small refiner under this rule and compliance with the rule is extended until 2015 for small refiners. Because of the extended compliance date, CRRM has not begun engineering work at this time. CVR anticipates that capital

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

expenditures to comply with the rule will not begin before 2013. Additionally, EPA has proposed changes to the Renewable Fuel Standards (RFS) that, when finalized, may impact petroleum product demand in the future. Due to mandates in the rule requiring increasing volumes of renewable fuels to replace petroleum products in the U.S. motor fuel market, CVR may be impacted by increased costs to accommodate mandated renewable fuel volumes. CRRM is a small refiner under the current RFS rules and would be subject to any extended compliance dates under the rule when finalized.

In March 2004, CRRM entered into a Consent Decree (the Consent Decree) with EPA and the Kansas Department of Health and Environment (KDHE), pursuant to which CRRM agreed, among other things, to install controls to reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM) from its fluid catalytic cracking unit (FCCU) by January 1, 2011. See Item 1 Business Environmental Matters The Federal Clean Air Act Air Emissions and Item 1A Risk Factors Risks Related to Our Entire Business Environmental laws and regulation could require CRRM to make substantial capital expenditures to remain in compliance or to remediate current or future contamination that could give rise to material liabilities in our Form 10-K for the year ended December 31, 2008 for additional information related to the Consent Decree. To date, CRRM has materially complied with the Consent Decree. On June 30, 2009, CRRM submitted a force majeure notice to EPA and KDHE in which CRRM indicated that it believes it may be unable to meet the Consent Decree deadlines related to the installation of controls on the FCCU because of delays caused by the June/July 2007 flood. The force majeure notice requests a one-year extension of the January 1, 2011 deadline. CRRM has not received a response from EPA or KDHE.

Environmental expenditures are capitalized when such expenditures are expected to result in future economic benefits. For the three months ended June 30, 2009 and 2008, capital environmental expenditures were $5,404,000 and $13,888,000, respectively. For the six months ended June 30, 2009 and 2008, capital environmental expenditures totaled $9,367,000 and $29,361,000, respectively. These expenditures were incurred to improve the efficiency of the operations.

CRRM, CRNF, CRCT and CRT believe they are in substantial compliance with existing EHS rules and regulations. There can be no assurance that the EHS matters described above or other EHS matters which may develop in the future will not have a material adverse effect on the Company s business, financial condition, or results of operations.

(12) Fair Value Measurements

In September 2006, the FASB issued SFAS 157. This statement established a single authoritative definition of fair value when accounting rules require the use of fair value, set out a framework for measuring fair value, and required additional disclosures about fair value measurements. SFAS 157 clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants.

SFAS 157 discusses valuation techniques, such as the market approach (prices and other relevant information generated by market conditions involving identical or comparable assets or liabilities), the income approach (techniques to convert future amounts to single present amounts based on market expectations including present value techniques and option-pricing), and the cost approach (amount that would be required to replace the service capacity of an asset which is often referred to as replacement cost). SFAS 157 utilizes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three broad levels. The following is a brief description of those three levels:

Level 1 Quoted prices in active market for identical assets and liabilities

Level 2 Other significant observable inputs (including quoted prices in active markets for similar assets or liabilities)

Level 3 Significant unobservable inputs (including the Company s own assumptions in determining the fair value)

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the assets and liabilities measured at fair value on a recurring basis, by input level, as of June 30, 2009 (in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents (money market account)	$ 59,193			$ 59,193
Receivable from swap counterparty current (Cash Flow Swap)		912		912
Payable to swap counterparty current (Cash Flow Swap)		(2,701)		(2,701)
Other current liabilities (Interest Rate Swap)		(5,534)		(5,534)

As of June 30, 2009, the only financial assets and liabilities that are measured at fair value on a recurring basis are the Company s money market account and derivative instruments. See Note 13 (Derivative Financial Instruments) for a discussion of the Cash Flow Swap and Interest Rate Swap. The Company s derivative contracts giving rise to assets or liabilities under Level 2 are valued using pricing models based on other significant observable inputs.

(13) Derivative Financial Instruments

Gain (loss) on derivatives, net consisted of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Realized gain (loss) on cash flow swap agreements	$ (2,701)	$ (52,437)	$ (18,416)	$ (73,953)
Unrealized gain (loss) on cash flow swap agreements	(19,876)	(15,990)	(39,990)	(29,896)
Realized gain (loss) on other agreements	(5,814)	(13,021)	(6,817)	(21,014)
Unrealized gain (loss) on other agreements	(225)	(1,781)	(62)	(625)
Realized gain (loss) on interest rate swap agreements	(1,354)	(947)	(3,064)	(425)
Unrealized gain (loss) on interest rate swap agreements	737	4,871	2,255	(1,263)
Total gain (loss) on derivatives, net	$ (29,233)	$ (79,305)	$ (66,094)	$ (127,176)

CVR is subject to price fluctuations caused by supply and demand conditions, weather, economic conditions, interest rate fluctuations and other factors. To manage price risk on crude oil and other inventories and to fix margins on certain future production, the Company may enter into various derivative transactions. The Company, as further described below, entered into certain commodity derivative contracts (i.e., the Cash Flow Swap) and an interest rate swap as required by the long-term debt agreements. The commodity derivative contracts are for the purpose of managing price risk on crude oil and finished goods and the interest rate swap is for the purpose of managing interest rate risk.

CVR has adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* which imposes extensive record-keeping requirements in order to designate a derivative financial instrument as a hedge. CVR holds derivative financial instruments, such as exchange-traded crude oil futures, certain over-the-counter forward swap agreements and interest rate swap agreements, which it believes provide an economic hedge on future transactions, but such instruments are not designated as hedges. Gains or losses related to the change in fair value and periodic settlements of these derivative financial instruments are classified as gain (loss) on derivatives, net in the Consolidated Statements of Operations.

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CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash Flow Swap

At June 30, 2009, CVR s Petroleum Segment held commodity derivative contracts (the Cash Flow Swap) for the period from July 1, 2005 to June 30, 2010 with a related party. See Note 14 (Related Party Transactions). The Cash Flow Swap agreements were originally executed on June 16, 2005 in conjunction with the acquisition by CALLC of all the outstanding stock held by Coffeyville Group Holdings, LLC and were required under the terms of the long-term debt agreements. The 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. The Cash Flow Swap agreements were executed at the prevailing market rate at the time of execution. At June 30, 2009, the notional open amounts under the Cash Flow Swap agreements were 5,931,250 barrels of crude oil, 124,556,250 gallons of unleaded gasoline and 124,556,250 gallons of heating oil. These positions are marked to market at each reporting date and result in unrealized gains (losses) using a valuation method that utilizes quoted market prices and assumptions. All unrealized gains and losses are currently recognized in the Company s Consolidated Statements of Operations. The realized gain or loss from the Cash Flow Swap is settled quarterly. All of the activity related to the commodity derivative contracts is reported in the Petroleum Segment.

As noted above, the counterparty to the Company s Cash Flow Swap agreement is a related party. As prudent, the Company from time-to-time considers counterparty credit risk. The maximum amount of loss due to the credit risk of the counterparty, should the counterparty fail to perform according to the terms of the contracts, is contingent upon the unsettled portion of the Cash Flow Swap, if any. For the Company to be at-risk the unsettled portion of the Cash Flow Swap would need to be in a net receivable position. Based upon the quoted market prices as of June 30, 2009, the Company recorded a current receivable related to the Cash Flow Swap. As such, all or a portion of the receivable could be at-risk should the counterparty fail to perform. The Company originally provided a letter of credit totaling $150,000,000, issued in support of the Cash Flow Swap, which was reduced to $60,000,000 effective June 1, 2009.

Interest Rate Swap

At June 30, 2009, CRLLC held derivative contracts known as Interest Rate Swap agreements (the Interest Rate Swap) that converted CRLLC s floating-rate bank debt into 4.195% fixed-rate debt on a notional amount of $180,000,000. Half of the Interest Rate Swap agreements are held with a related party (as described in Note 14, Related Party Transactions), and the other half are held with a financial institution that is a lender under CRLLC s long-term debt agreement. The Interest Rate Swap agreements carry the following terms:

Period Covered	Notional Amount	Fixed Interest Rate
March 31, 2009 to March 30, 2010	$ 180 million	4.195%
March 31, 2010 to June 30, 2010	110 million	4.195%

CVR pays the fixed rates listed above and receives a floating rate based on three month LIBOR rates, with payments calculated on the notional amounts listed above. The notional amounts do not represent actual amounts exchanged by the parties but instead represent the amounts on which the contracts are based. The Interest Rate Swap results in both realized and unrealized gains or losses and is included in the Company s Consolidated Statements of Operations. The realized gain or loss from the Interest Rate Swap is settled quarterly. The Interest Rate Swap is marked to market each reporting date. Transactions related to the Interest Rate Swap agreements are not allocated to the Petroleum or Nitrogen Fertilizer segments.

The Interest Rate Swap has two counterparties. As noted above, one half of the Interest Rate Swap agreements are held with a related party. As of June 30, 2009, both counterparties had an investment-grade debt rating. The maximum amount of loss due to the credit risk of the counterparty, should the counterparty fail to perform according to the terms of the contracts, is contingent upon the unsettled portion of the Interest Rate Swap, if any. For the Company to be at-risk the unsettled portion of the Interest Rate Swap would need to be in a net receivable

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

position. As of June 30, 2009, the Company s Interest Rate Swap was in a payable position and thus would not be considered at-risk as it relates to risk posed by the swap counterparties.

(14) Related Party Transactions

The Goldman Sachs Funds and the Kelso Funds together own a majority of the common stock of the Company.

Cash Flow Swap

CRLLC entered into certain crude oil, heating oil and gasoline swap agreements (referred to above and herein as the Cash Flow Swap) with J. Aron & Company (J. Aron), a subsidiary of GS. These agreements were entered into on June 16, 2005, with an expiration date of June 30, 2010 (as described in Note 13, Derivative Financial Instruments). Realized and unrealized losses totaling $22,577,000 and $68,427,000 were recognized related to these swap agreements for the three months ended June 30, 2009 and 2008, respectively, and are reflected in gain (loss) on derivatives, net in the Consolidated Statements of Operations. For the six months ended June 30, 2009 and 2008, the Company recognized losses of $58,406,000 and $103,849,000, respectively, which are reflected in loss on derivatives, net in the Consolidated Statements of Operations. In addition, the Consolidated Balance Sheet at June 30, 2009, includes an asset of $912,000 included in current receivable from swap counterparty, which represents the unrealized position associated with the Cash Flow Swap at that date. Also reflected in the Consolidated Balance Sheet at June 30, 2009 is a payable to swap counterparty for $2,701,000, which represents the realized loss on the Cash Flow Swap for the three months ended June 30, 2009. As of December 31, 2008, the Company recorded short-term and long-term receivable from swap counterparty of $32,630,000 and $5,632,000, respectively, for the net gain on the Cash Flow Swap as of December 31, 2008.

J. Aron Deferrals

As a result of the June/July 2007 flood and the related temporary cessation of business operations, the Company entered into deferral agreements for amounts owed to J. Aron under the Cash Flow Swap discussed above. The amount deferred, excluding accrued interest, totaled $123,681,000. Of the deferred balances, $61,306,000 had been repaid as of December 31, 2008. The remaining deferred liability is included in the Consolidated Balance Sheet at December 31, 2008 in payable to swap counterparty. Accrued interest related to the deferral agreement for the year ended December 31, 2008 totaled $202,000 and is included in other current liabilities. Interest expense related to the deferral agreement totaled $0 and $1,336,000 for the three months ended June 30, 2009 and 2008, respectively. Interest expense related to the deferral agreement totaled $307,000 and $2,585,000 for the six months ended June 30, 2009 and 2008, respectively.

In the first quarter of 2009, the Company repaid the entire remaining deferral obligation of $62,375,000, including accrued interest of $509,000, resulting in the Company being released from any and all of its obligations under the deferral agreements.

Interest Rate Swap

On June 30, 2005, the Company also entered into three Interest Rate Swap agreements (referred to above as the Interest Rate Swap) with J. Aron (as described in Note 13, Derivative Financial Instruments). Gains totaling $311,000 and $1,962,000 were recognized related to these swap agreements for the three months ended June 30, 2009 and 2008, respectively, and are reflected in gain (loss) on derivatives, net in the Consolidated Statements of Operations. Losses totaling $408,000 and $851,000 were recognized related to these swap agreements for the six months ended June 30, 2009 and 2008, respectively, and are reflected in gain (loss) on derivatives, net in the Consolidated Statements of Operations. In addition, the Consolidated Balance Sheet at June 30, 2009 and December 31, 2008 includes $2,769,000 and $2,595,000, respectively, in other current liabilities. In addition to the other current liability, the Company recorded $1,298,000 in other long-term liabilities related to the same agreements as of December 31, 2008.

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CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Crude Oil Supply Agreement

During 2008, the Company was a counterparty to a crude oil supply agreement with J. Aron. Under the agreement, the parties agreed to negotiate the cost of each barrel of crude oil to be purchased from a third party, and CRRM agreed to pay J. Aron a fixed supply service fee per barrel over the negotiated cost of each barrel of crude purchased. The cost was adjusted further using a spread adjustment calculation based on the time period the crude oil was estimated to be delivered to the refinery, other market conditions, and other factors deemed appropriate. The Company recorded $0 and $8,211,000 on the Consolidated Balance Sheet at June 30, 2009 and December 31, 2008, respectively, in prepaid expenses and other current assets for the prepayment of crude oil. In addition, $0 and $20,063,000 were recorded in inventory and $0 and $2,757,000 were recorded in accounts payable at June 30, 2009 and December 31, 2008, respectively. Expenses associated with this agreement included in cost of product sold (exclusive of depreciation and amortization) for the three and six months ended June 30, 2008 totaled $907,915,000 and $1,674,128,000, respectively. For the three and six months ended June 30, 2009, there were no expenses included in cost of product sold (exclusive of depreciation and amortization) as the crude oil supply agreement was terminated with J. Aron effective December 31, 2008. The Company entered into a new crude oil supply agreement with Vitol Inc. (Vitol), an unrelated party, effective December 31, 2008. The original crude oil supply agreement with Vitol included an initial term of two years. On July 7, 2009, the Company entered into an amendment with Vitol extending the term by a period of one year, terminating on December 31, 2011.

Cash and Cash Equivalents

The Company opened a highly liquid money market account with average maturities of less than 90 days within the Goldman Sachs fund family in September 2008. As of June 30, 2009 and December 31, 2008, the balance in the account was approximately $59,193,000 and $149,000, respectively. For the three and six months ended June 30, 2009, the account earned interest income of $29,000 and $44,000, respectively.

Other

For the six months ended June 30, 2009, the Company purchased approximately $115,000 of Fluid Catalytic Cracking Unit additives from Intercat, Inc. A director of the Company, Mr. Regis Lippert, is also the Director, President, CEO and majority shareholder of Intercat, Inc.

(15) Business Segments

CVR measures segment profit as operating income for Petroleum and Nitrogen Fertilizer, CVR s two reporting segments, based on the definitions provided in SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*. All operations of the segments are located within the United States.

Petroleum

Principal products of the Petroleum Segment are refined fuels and petroleum refining by-products including pet coke. CVR sells the pet coke to the Partnership for use in the manufacturing of nitrogen fertilizer at the adjacent nitrogen fertilizer plant. CVR uses a per-ton transfer price to record intercompany sales on the part of the Petroleum Segment and corresponding intercompany cost of product sold (exclusive of depreciation and amortization) for the Nitrogen

Fertilizer Segment. The per ton transfer price paid, pursuant to the pet coke supply agreement that became effective October 24, 2007, is based on the lesser of a pet coke price derived from the price received by the fertilizer segment for UAN (subject to a UAN based price ceiling and floor) and a pet coke price index for pet coke. The intercompany transactions are eliminated in the Other Segment. Intercompany sales included in petroleum net sales were $2,002,000 and $2,800,000 for the three months ended June 30, 2009 and 2008, respectively. Intercompany sales included in petroleum net sales were $5,020,000 and $5,606,000 for the six months ended June 30, 2009 and 2008, respectively.

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CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Petroleum Segment recorded intercompany cost of product sold (exclusive of depreciation and amortization) for the hydrogen sales described below under Nitrogen Fertilizer for the three and six months ended June 30, 2009 of $(443,000) and $215,000, respectively. For the three and six months ended June 30, 2008 the Petroleum Segment purchased hydrogen from the Partnership and recorded cost of product sold (exclusive of depreciation and amortization) of $2,600,000 and $7,891,000, respectively.

Nitrogen Fertilizer

The principal product of the Nitrogen Fertilizer Segment is nitrogen fertilizer. Intercompany cost of product sold (exclusive of depreciation and amortization) for the pet coke transfer described above was $2,549,000 and $2,325,000 for the three months ended June 30, 2009 and 2008, respectively. Intercompany cost of product sold (exclusive of depreciation and amortization) for the pet coke transfer described above was $6,085,000 and $4,871,000 for the six months ended June 30, 2009 and 2008, respectively.

Pursuant to the feedstock agreement, the Company s segments have the right to transfer excess hydrogen to one another. Sales of hydrogen to the Petroleum Segment have been reflected as net sales for the Nitrogen Fertilizer Segment. Receipts of hydrogen from the Petroleum Segment have been reflected in cost of product sold (exclusive of depreciation and amortization) for the Nitrogen Fertilizer Segment. The Nitrogen Fertilizer Segment recorded net sales from intercompany hydrogen sales of $1,000 and $659,000 for the three and six months ended June 30, 2009, respectively and recorded cost of product sold (exclusive of depreciation and amortization) of $444,000 and $444,000 for the three and six months ended June 30, 2009, respectively, for the purchase of intercompany hydrogen. For the three and six months ended June 30, 2008 the Nitrogen Fertilizer Segment recorded net sales of hydrogen to the Petroleum Segment totaling $2,600,000 and $7,891,000, respectively.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Segment

The Other Segment reflects intercompany eliminations, including significant intercompany eliminations of receivables and payables between the segments, cash and cash equivalents, all debt related activities, income tax activities and other corporate activities that are not allocated to the operating segments.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(in thousands)			
Net sales				
Petroleum	$ 739,952	$ 1,459,101	$ 1,285,234	$ 2,627,602
Nitrogen Fertilizer	55,355	58,802	123,144	121,401
Intersegment eliminations	(2,003)	(5,400)	(5,679)	(13,497)
Total	$ 793,304	$ 1,512,503	$ 1,402,699	$ 2,735,506
Cost of product sold (exclusive of depreciation and amortization)				
Petroleum	$ 581,657	$ 1,285,556	$ 999,255	$ 2,320,642
Nitrogen Fertilizer	8,245	6,846	16,927	15,791
Intersegment eliminations	(2,267)	(4,925)	(6,942)	(12,762)
Total	$ 587,635	$ 1,287,477	$ 1,009,240	$ 2,323,671
Direct operating expenses (exclusive of depreciation and amortization)				
Petroleum	$ 32,973	$ 42,684	$ 67,595	$ 82,974
Nitrogen Fertilizer	21,474	19,652	43,086	39,918
Other				
Total	$ 54,447	$ 62,336	$ 110,681	$ 122,892
Net costs associated with flood				
Petroleum	$ (101)	$ 3,369	$ 80	$ 8,902
Nitrogen Fertilizer		34		17
Other		493		740
Total	$ (101)	$ 3,896	$ 80	$ 9,659
Depreciation and amortization				
Petroleum	$ 15,962	$ 16,273	$ 31,840	$ 31,150

Nitrogen Fertilizer	4,720	4,486	9,336	8,963
Other	425	321	840	602
Total	$ 21,107	$ 21,080	$ 42,016	$ 40,715
Operating income (loss)				
Petroleum	$ 96,232	$ 101,878	$ 160,891	$ 165,495
Nitrogen Fertilizer	16,527	23,145	45,809	49,162
Other	(4,315)	(2,071)	(7,296)	(4,347)
Total	$ 108,444	$ 122,952	$ 199,404	$ 210,310
Capital expenditures				
Petroleum	$ 6,637	$ 16,589	$ 14,029	$ 39,130
Nitrogen Fertilizer	2,136	6,302	9,567	9,119
Other	(116)	588	979	1,386
Total	$ 8,657	$ 23,479	$ 24,575	$ 49,635

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CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	As of June 30, 2009	As of December 31, 2008
	(in thousands)	
Total assets		
Petroleum	$ 1,063,412	$ 1,032,223
Nitrogen Fertilizer	682,060	644,301
Other	(116,684)	(66,041)
Total	$ 1,628,788	$ 1,610,483
Goodwill		
Petroleum	$	$
Nitrogen Fertilizer	40,969	40,969
Other		
Total	$ 40,969	$ 40,969

(16) Subsequent Events

Insurance Renewal

On July 1, 2009, we renewed and/or renegotiated our primary lines of insurance including workers compensation, automobile and general liability, umbrella and excess liability, property and business interruption, cargo, terrorism and crime. The Company entered into an insurance premium financing agreement in July 2009 to finance $10,000,000 of the $13,438,000 insurance premium.

Crude Oil Supply Agreement

On July 7, 2009, CRRM entered into an amendment to the Crude Oil Supply Agreement, dated December 2, 2008, with Vitol. The amendment extends the initial term of the Supply Agreement from two to three years ending December 31, 2011, whereby Vitol agrees to continue to provide crude oil supply and logistics intermediation on behalf of CRRM.

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Item 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes and with the statistical information and financial data appearing in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, as well as our Annual Report on Form 10-K for the year ended December 31, 2008. Results of operations for the three and six months ended June 30, 2009 are not necessarily indicative of results to be attained for any other period.

Forward-Looking Statements

This Form 10-Q, including this Management s Discussion and Analysis of Financial Condition and Results of Operations, contains forward-looking statements as defined by the Securities and Exchange Commission (the SEC). Such statements are those concerning contemplated transactions and strategic plans, expectations and objectives for future operations. These include, without limitation:

statements, other than statements of historical fact, that address activities, events or developments that we expect, believe or anticipate will or may occur in the future;

statements relating to future financial performance, future capital sources and other matters; and

any other statements preceded by, followed by or that include the words anticipates, believes, expects, plans, intends, estimates, projects, could, should, may, or similar expressions.

Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Form 10-Q, including this Management s Discussion and Analysis of Financial Condition and Results of Operations, are reasonable, we can give no assurance that such plans, intentions or expectations will be achieved. These statements are based on assumptions made by us based on our experience and perception of historical trends, current conditions, expected future developments and other factors that we believe are appropriate in the circumstances. Such statements are subject to a number of risks and uncertainties, many of which are beyond our control. You are cautioned that any such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in the forward-looking statements as a result of various factors, including but not limited to those set forth under Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2008. Such factors include, among others:

volatile prices for petroleum products resulting in volatile refining margins;

exposure to the risks associated with volatile crude prices;

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

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

losses due to the Cash Flow Swap;

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

competition in the petroleum and nitrogen fertilizer businesses;

continued low natural gas prices, which historically has correlated with the market price of nitrogen fertilizer products;

the cyclical nature of the nitrogen fertilizer business;

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

the hazardous 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 reliance of the nitrogen fertilizer business on third-party providers of transportation services and equipment;

operating hazards and interruptions, including unscheduled downtime and maintenance;

capital expenditures required by environmental laws and regulations for the petroleum and nitrogen fertilizer businesses;

state and federal environmental, economic, health and safety, energy and other policies and regulations, and changes therein;

changes in our credit profile;

our indebtedness;

severe weather conditions and natural disasters;

the supply and price levels of essential raw materials;

the slowdown in the credit markets; and

changes in global economic conditions.

All forward-looking statements contained in this Form 10-Q speak only as of the date of this document. We undertake no obligation to update or revise publicly any forward-looking statements to reflect events or circumstances that occur after the date of this Form 10-Q, or to reflect the occurrence of unanticipated events.

Company Overview

CVR Energy, Inc. and, unless the context requires otherwise, its subsidiaries (CVR , the Company , we , us or our independent refiner and marketer of high value transportation fuels. In addition, we currently own all of the interests (other than the managing general partner interest (managing GP interest) and associated incentive distribution rights (the IDRs) in CVR Partners, LP (the Partnership) a limited partnership which produces nitrogen fertilizers, ammonia and urea ammonium nitrate (UAN).

Any references to the Company as of a date prior to October 16, 2007 and subsequent to June 24, 2005 are to Coffeyville Acquisition LLC (CALLC) and its subsidiaries. CALLC formed CVR Energy, Inc. as a wholly owned subsidiary, incorporated in Delaware in September 2006, in order to effect an initial public offering, which was consummated on October 26, 2007. In conjunction with the initial public offering, a restructuring occurred in which CVR became a direct or indirect owner of all of the subsidiaries of CALLC. Additionally, in connection with the initial public offering, CALLC was split into two entities: CALLC and Coffeyville Acquisition II LLC (CALLC II).

We operate under two business segments: petroleum and nitrogen fertilizer. Throughout the remainder of this document, our business segments are referred to as our petroleum business and our nitrogen fertilizer business, respectively.

Petroleum business. Our petroleum business includes a 115,000 barrels per day (bpd) complex full coking medium-sour crude refinery in Coffeyville, Kansas. In addition to the refinery, we own and operate supporting businesses that include (1) a crude oil gathering system with a gathering capacity in excess of 30,000 bpd, serving central Kansas, northern Oklahoma, western Missouri, eastern Colorado and southwest Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, (3) a 145,000 bpd pipeline system that transports crude oil to our refinery and associated crude oil storage tanks with a capacity of 1.2 million barrels and (4) 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 (Magellan) refined products distribution systems. We also lease 2.7 million barrels of storage capacity at Cushing, Oklahoma. 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 the Magellan pipeline and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise Products Operating, L.P. 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. Cushing is supplied by numerous pipelines from locations including the U.S. Gulf Coast and Canada, providing us with access to virtually any crude oil variety in the world capable of being transported by pipeline.

Crude oil is supplied to our refinery through our owned and leased gathering system, and by Plains Pipeline, L.P. pipeline from Cushing, Oklahoma. We also maintain capacity on the Spearhead Pipeline receiving crude oil from Canada, and receive foreign and deepwater domestic crude oils via the Seaway Pipeline system. We also maintain leased storage in Cushing to facilitate optimal crude oil purchasing and blending. Our refinery blend consists of a combination of crude oil grades, including onshore and offshore domestic grades, various Canadian medium and heavy sours and sweet synthetics, and optionality of a variety of South American, North Sea, Middle East and West African imported grades. The access to a variety of crude oils coupled with the complexity of our refinery allows us to purchase crude oil at a discount to West Texas Intermediate (WTI). Our consumed crude cost discount to WTI for the second quarter of 2009 was $(6.38) per barrel compared to $(4.46) per barrel in the second quarter of 2008.

Nitrogen fertilizer business. The nitrogen fertilizer business consists of a nitrogen fertilizer plant in Coffeyville, Kansas which includes two pet coke gasifiers. The nitrogen fertilizer plant is the only operation in North America utilizing a pet coke gasification process to produce nitrogen fertilizers (based on data provided by Blue Johnson & Associates). Its redundant train gasifier provides good on-stream reliability and with the use of low cost by-product pet coke feed, produces high purity hydrogen. This hydrogen is then converted to ammonia at a related ammonia synthesis plant. Ammonia is further upgraded into UAN solution in a related UAN unit. Pet coke is a low value by-product of the refinery coking process. On average during the last five years, more than 77% of the pet coke consumed by the nitrogen fertilizer plant was produced by our refinery. The nitrogen fertilizer business obtains most of its pet coke via a long-term coke supply agreement with our refinery.

The nitrogen fertilizer manufacturing facility is comprised of (1) an 84 million standard cubic foot per day gasifier complex, which consumes approximately 1,500 tons per day of pet coke to produce hydrogen, (2) a 1,225 ton-per-day ammonia unit and (3) a 2,025 ton-per-day UAN unit. In 2008, the nitrogen fertilizer business produced approximately 359,120 tons of ammonia, of which approximately 69% was upgraded into approximately 599,172 tons of UAN.

General Overview. Due to the weakness of the general economy, including the tightness in the credit markets, and short-term tightening in demand of the petroleum and nitrogen fertilizer products, both the petroleum business and nitrogen fertilizer business are focused on controlling operational expenditures and minimizing capital spending while maintaining operational efficiency and safety. Inventory management practices are being employed to respond to the changes in demand levels which impact our production volumes in both businesses.

Major Influences on Results of Operations

Petroleum Business

Our earnings and cash flows from our petroleum 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. These factors include the supply of, and demand for, crude oil, gasoline and other refined products which in turn depend on 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. 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 changes in the value of our 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, domestic and 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.

In order to assess our operating performance, we compare our net sales, less cost of product sold against a widely used industry refining margin benchmark. The industry refining margin is calculated by assuming that two barrels of benchmark light sweet crude oil are converted 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, we refer to the benchmark as the NYMEX 2-1-1 crack spread, or simply, the 2-1-1 crack spread.

Although the 2-1-1 crack spread is a benchmark for our refinery margin, because our refinery has certain feedstock costs and 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 our margin. Our refinery is able to process a blend of crude oil that includes quantities of heavy and medium sour crude oil that have historically cost less than WTI. We measure the cost advantage of our crude oil slate by calculating the spread between the price of our delivered crude oil and the price of WTI. The spread is referred to as our consumed crude differential. The consumed crude differential will move directionally with changes in the West Texas Sour crude oil (WTS) differential to WTI and the West Canadian Select (WCS) differential to WTI as both these differentials indicate the relative price of heavier, more sour, slate to WTI, directly impacting refinery margin. The correlation between our consumed crude differential and published differentials will vary depending on the volume of 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 WCS differential was $7.45 and $22.94 per barrel, for the three months ended June 30, 2009 and 2008, respectively. The WTI less WTS differential was $1.47 and $4.62 per barrel for the three months ended June 30, 2009 and 2008, respectively. While the sweet-sour and heavy-sour crude oil markets remained tight during the second quarter of 2009, the related impact of this on our crude differential was offset in part due to the ongoing contango in the WTI crude oil market. Contango markets are characterized by prices for future delivery that are higher than the current or spot price of the commodity. Our quarterly crude oil costs benefited in the second quarter of 2009 from the ongoing contango. Our consumed crude oil less WTI differential was $(6.38) and $(4.46) per barrel for the three months ended June 30, 2009 and 2008, respectively.

We produce a significant 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 in our region include the logistics cost for U.S. Gulf Coast refineries to ship into our region. The result of this logistical advantage and the fact that the actual product specifications used to determine the NYMEX are different from the actual production in our 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 Ultra Low Sulfur Diesel PADD II, Group 3 vs. NYMEX basis, or Ultra Low Sulfur Diesel basis. If gasoline and heating oil basis are greater than zero, this would mean that prices in our marketing area exceed those used in the 2-1-1 crack spread. Ultra Low Sulfur Diesel basis for the second quarter 2009 and 2008 was $0.53 and $4.17 per barrel, respectively. Gasoline basis for the second quarter 2009 was $(1.73) per barrel, compared to $(3.61) per barrel in the second quarter of 2008.

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 which is comprised primarily of electrical cost and natural gas. We are therefore sensitive to the movements of natural gas prices.

Consistent, safe, and reliable operations at our refinery are key to our financial performance and results of operations. Unplanned downtime at our refinery may result in lost margin opportunity, increased maintenance expense, 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. The refinery generally undergoes a facility turnaround every four to five years.

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The length of the turnaround is contingent upon the scope of work to be completed. The last refinery turnaround was completed in April 2007, and the next refinery turnaround is scheduled for the fourth quarter of 2011.

Because petroleum feedstocks and products are essentially commodities, we have no control over the changing market. Therefore, the lower target inventory position we are able to maintain significantly reduces the impact of commodity price volatility on our 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 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.

As the petroleum business continues to maintain high product output, product shipping logistics are beginning to surface as a potential limitation. We are continuing to evaluate and look at alternatives for shipping refined products out of the refinery. We do not expect any outbound transportation constraints to have a material or significant impact to the results of the operations of the petroleum business.

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, our nitrogen fertilizer business uses minimal natural gas 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 most of the pet coke feedstock needed pursuant to a long-term coke supply agreement we entered into in October 2007. The price paid by the nitrogen fertilizer business pursuant to the coke supply agreement with our refinery is 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) and a coke price index for pet coke.

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. These factors depend on 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 nitrogen fertilizer products sell at low prices, high natural gas prices do not force the nitrogen fertilizer business to shut down its operations as is the case with our competitors who rely heavily on natural gas instead of pet coke as a primary feedstock.

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, domestic and 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 nitrogen fertilizers is affected by the aggregate crop planting decisions and nitrogen 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 nitrogen fertilizer they apply depend on factors such as crop prices, their current liquidity, soil conditions, weather patterns and the types of crops planted.

The United States Department of Agriculture reported on June 30, 2009 that growers planted an estimated 87 million acres of corn in 2009. This is the second largest planted acreage since 1946, behind 2007. The agricultural sector of the economy; however, has not remained entirely immune to the overall slowdown in both the domestic and world economies, and, in fact, fertilizer usage declined this year. A factor in this decline was the extremely wet weather experienced in the United States during the spring planting season.

In order to assess the operating performance of the nitrogen fertilizer business, we calculate plant gate price to determine our operating margin. Plant gate price refers to the unit price of fertilizer, in dollars per ton, offered on a delivered basis, excluding shipment costs. Instead of experiencing high variability in the cost of raw materials, the nitrogen fertilizer business utilizes less than 1% of the natural gas used by natural gas-based fertilizer producers.

Because the nitrogen fertilizer plant has certain logistical advantages relative to end users of ammonia and UAN and demand relative to our production has remained high, the nitrogen fertilizer business primarily targets end users in the U.S. farm belt where it incurs lower freight costs as compared to competitors. The nitrogen fertilizer business does not incur any barge or pipeline freight charges when it sells in these markets, giving us a distribution cost advantage over U.S. Gulf Coast importers. Selling products to customers within economic rail transportation limits of the nitrogen 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. During 2008, the nitrogen fertilizer business upgraded approximately 69% 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 also directly affects its profitability. Using a pet coke gasification process, the nitrogen fertilizer business has significantly higher fixed costs than natural gas-based fertilizer plants. Major fixed operating expenses include electrical energy, employee labor, maintenance, including contract labor, outside services, property taxes and insurance. These costs comprise the fixed costs associated with the nitrogen fertilizer plant.

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, 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.

The nitrogen fertilizer business generally undergoes a facility turnaround every two years. The turnaround typically lasts 15-20 days each turnaround year and costs approximately $3-5 million per turnaround. The facility underwent a turnaround in the fourth quarter of 2008, and the next facility turnaround is currently scheduled for the fourth quarter of 2010.

Factors Affecting Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable with prior periods or to our results of operations in the future for the reasons discussed below.

Cash Flow Swap

On June 16, 2005, CALLC entered into commodity derivative contracts (referred to as the Cash Flow Swap) with J. Aron & Company (J. Aron), a subsidiary of The Goldman Sachs Group, Inc. and a related party of ours. The Cash Flow Swap was subsequently assigned from CALLC to Coffeyville Resources, LLC (CRLLC), a wholly-owned subsidiary of CVR on June 24, 2005. The derivative took the form of three NYMEX swap agreements whereby if absolute (i.e., in dollar terms, not a percentage of crude oil prices) crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if absolute crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. Based upon expected crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 14% of crude oil capacity for the period of July 1, 2009 through June 30, 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 (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*. As a result, the Consolidated Statement of Operations reflects all the realized and unrealized gains and losses from this swap which can create significant changes between periods.

For the three months ended June 30, 2009 and 2008, we recorded net realized and unrealized losses of $22.6 million and $68.4 million, respectively, related to the Cash Flow Swap. For the six months ended June 30, 2009 and 2008, we recorded net realized and unrealized losses of $58.4 million and $103.8 million, respectively, related to the Cash Flow Swap.

Share-Based Compensation

Through a wholly-owned subsidiary, we have two Phantom Unit Appreciation Plans (the Phantom Unit Plans) whereby directors, employees, and service providers may be awarded phantom points at the discretion of the board of directors or the compensation committee. We account for awards under our Phantom Unit Plans as liability based awards. In accordance with FAS 123(R), the expense associated with these awards for 2009 is based on the current fair value of the awards which was derived from a probability-weighted expected return method. The probability-weighted expected return method involves a forward-looking analysis of possible future outcomes, the estimation of ranges of future and present value under each outcome, and the application of a probability factor to each outcome in conjunction with the application of the current value of our common stock price with a Black-Scholes option pricing formula, as remeasured at each reporting date until the awards are settled.

Also, in conjunction with the initial public offering in October 2007, the override units of CALLC were modified and split evenly into override units of CALLC and CALLC II. As a result of the modification, the awards were no longer accounted for as employee awards and became subject to the accounting guidance in EITF Issue No. 00-12, *Accounting by an Investor for Stock-Based Compensation Granted to Employees of an Equity Method Investee* and EITF Issue No. 96-18, *Accounting for Equity Investments that Are Issued to Other than Employees for Acquiring or in Conjunction with Selling Goods or Services*. In accordance with that accounting guidance, the expense associated with the awards is based on the current fair value of the awards which is derived under the same methodology as the Phantom Unit Plans, as remeasured at each reporting date until the awards vest. For the three and six months ended June 30, 2009, we increased compensation expense by $5.5 million and $9.3 million, respectively, as a result of the phantom and override unit share-based compensation awards. For the three and six months ended June 30, 2008, we reversed compensation expense by $10.8 million and $11.3 million, respectively.

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, Kansas. Our refinery and nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded, sustained damage and required repair. In addition to cost incurred for repairs to the facilities, we also incurred costs related to a discharge of crude oil from the facility that occurred on or about July 1, 2007.

We recorded pretax expenses, net of anticipated insurance recoveries of $(0.1) million and $0.1 million in net costs associated with the flood for the three and six months ended June 30, 2009, respectively, compared to pretax expenses, net of anticipated insurance recoveries of $3.9 million and $9.7 million for the same period in 2008. The net costs have declined significantly over the comparable periods as the majority of repairs and maintenance to the facilities associated with damage caused by the flood were completed by the second quarter of 2008. In addition, the majority of the environmental remedial actions were substantially complete as of January 31, 2009.

Income Taxes

On an interim basis, income taxes are calculated based upon an estimated annual effective tax rate for the annual period. The estimated annual effective tax rate changes primarily due to changes in projected annual pre-tax income (loss) as estimated at each interim period and in correlation with federal and state income tax credits projected to be generated for the year. Significantly higher amounts of federal income tax credits were generated in 2008 related to the production of ultra-low sulfur diesel fuel as well as significantly higher amounts of Kansas state income tax incentives generated under the High Performance Incentive Program (HPIP) in 2008. The decrease in the projected federal and state income tax credits generated for 2009 as compared to the level of projected pre-tax income, has increased the estimated annual effective tax rate for 2009 as compared to 2008.

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Results of Operations

The following tables summarize the financial data and key operating statistics for CVR and our two operating segments for the three and six months ended June 30, 2009 and 2008. The summary financial data for our two operating segments does not include certain selling, general and administrative expenses and depreciation and amortization related to our corporate offices. The following data should be read in conjunction with our condensed consolidated financial statements and the notes thereto included elsewhere in this Form 10-Q. All information in Management s Discussion and Analysis of Financial Condition and Results of Operations, except for the balance sheet data as of December 31, 2008, is unaudited.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(unaudited) (in millions, except share data)			
Consolidated Statement of Operations Data				
Net sales	$ 793.3	$ 1,512.5	$ 1,402.7	$ 2,735.5
Cost of product sold(1)	587.6	1,287.4	1,009.2	2,323.6
Direct operating expenses(1)	54.5	62.3	110.7	122.9
Selling, general and administrative expenses(1)	21.8	14.8	41.3	28.3
Net costs associated with flood(2)	(0.1)	3.9	0.1	9.7
Depreciation and amortization(3)	21.1	21.1	42.0	40.7
Operating income	$ 108.4	$ 123.0	$ 199.4	$ 210.3
Other income, net	0.9	0.9	0.9	1.8
Interest expense and other financing costs	(11.2)	(9.5)	(22.7)	(20.8)
Gain (loss) on derivatives, net	(29.2)	(79.3)	(66.1)	(127.2)
Loss on extinguishment of debt	(0.7)		(0.7)	
Income before income tax expense	$ 68.2	$ 35.1	$ 110.8	$ 64.1
Income tax expense	(25.5)	(4.1)	(37.5)	(10.9)
Net income(4)	$ 42.7	$ 31.0	$ 73.3	$ 53.2
Basic earnings per share	$ 0.49	$ 0.36	$ 0.85	$ 0.62
Diluted earnings per share	$ 0.49	$ 0.36	$ 0.85	$ 0.62
Weighted average common shares outstanding:				
Basic	86,244,152	86,141,291	86,243,949	86,141,291
Diluted	86,333,349	86,158,791	86,327,911	86,158,791

	As of June 30, 2009 (unaudited)	As of December 31, 2008

	(in millions)	
Balance Sheet Data		
Cash and cash equivalents	$ 73.3	$ 8.9
Working capital	247.3	128.5
Total assets	1,628.8	1,610.5
Total debt, including current portion	486.0	495.9
Total CVR stockholders equity	657.8	579.5

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(unaudited) (in millions)			
Cash Flow Data				
Net cash flow provided by (used in):				
Operating activities	54.8	(0.8)	91.5	23.3
Investing activities	(8.7)	(23.5)	(24.6)	(49.6)
Financing activities	(1.2)	19.8	(2.5)	16.4
Other Financial Data				
Capital expenditures for property, plant and equipment	$ 8.7	$ 23.5	$ 24.6	$ 49.6
Depreciation and amortization	21.1	21.1	42.0	40.7
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(5)	54.7	40.6	97.4	71.2

(1) Amounts are shown exclusive of depreciation and amortization.

(2) Represents the approximate net costs associated with the June/July 2007 flood and crude oil spill that are not probable of recovery.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(unaudited) (in millions)			
Depreciation and amortization excluded from cost of product sold	$ 0.7	$ 0.6	$ 1.4	$ 1.2
Depreciation and amortization excluded from direct operating expenses	19.9	20.1	39.7	38.8
Depreciation and amortization excluded from selling, general and administrative expenses	0.5	0.4	0.9	0.7
Total depreciation and amortization	$ 21.1	$ 21.1	$ 42.0	$ 40.7

(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:

	Three Months	Six Months

	Ended June 30,		Ended June 30,	
	2009	2008	2009	2008
	(unaudited) (in millions)			
Loss on extinguishment of debt(a)	$ 0.7	$	$ 0.7	$
Funded letter of credit expense and interest rate swap not included in interest expense(b)	3.6	2.4	7.9	3.3
Unrealized net (gain) loss from Cash Flow Swap	19.9	16.0	40.0	29.9
Share-based compensation expense(c)	5.6	(10.7)	9.5	(11.1)

(a) Represents the write-off of deferred financing costs associated with the reduction of the funded letter of credit facility of $150.0 million to $60.0 million, effective June 1, 2009, issued in support of the Cash Flow Swap.

(b) Consists of fees which are expensed to selling, general and administrative expenses in connection with the funded letter of credit facility of $60.0 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 consolidated adjusted EBITDA in the credit facility.

(c) Represents the impact of share-based compensation awards.

(5) Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for the derivative transaction that was executed in conjunction with the acquisition of Coffeyville Group Holdings, LLC by CALLC on June 24, 2005. On June 16, 2005, CALLC entered into the Cash Flow Swap with J. Aron. The Cash Flow Swap was subsequently assigned from CALLC to CRLLC on June 24, 2005. The derivative took the form of three NYMEX swap agreements whereby if absolute (i.e., in dollar terms, not a percentage of crude oil prices) crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if absolute crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. Based upon expected crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 14% of crude oil capacity for the period from July 1, 2009 through June 30, 2010.

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 are accounted for as an asset or liability on our balance sheet, as applicable. As the absolute crack spreads increase, we are required to record an increase in this liability account with a corresponding expense entry to be made to our Statements of Operations. Conversely, as absolute 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 unrealized gains and losses, and given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income (loss) 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 GAAP net income results as well as Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income (loss) 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 gain or loss from Cash Flow Swap net of its related tax effect.

Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap is not a recognized financial measure 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 in evaluating our business. Because Net income (loss) 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 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(unaudited)			
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap	$ 54.7	$ 40.6	$ 97.4	$ 71.2
Plus:				
Unrealized gain (loss) from Cash Flow Swap, net of taxes	(12.0)	(9.6)	(24.1)	(18.0)
Net income	$ 42.7	$ 31.0	$ 73.3	$ 53.2

Petroleum Business Results of Operations

The following tables below provide an overview of the petroleum business results of operations, relevant market indicators and its key operating statistics:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(unaudited) (in millions, except as otherwise indicated)			
Petroleum Business Financial Results				
Net sales	$ 740.0	$ 1,459.1	$ 1,285.2	$ 2,627.6
Cost of product sold(1)	581.7	1,285.6	999.3	2,320.6
Direct operating expenses(1)(3)	33.0	42.7	67.6	83.0
Net costs associated with flood	(0.1)	3.4	0.1	8.9
Depreciation and amortization	16.0	16.3	31.8	31.2
Gross profit(3)	$ 109.4	$ 111.1	$ 186.4	$ 183.9
Plus direct operating expenses(1)	33.0	42.7	67.6	83.0
Plus net costs associated with flood	(0.1)	3.4	0.1	8.9
Plus depreciation and amortization	16.0	16.3	31.8	31.2
Refining margin(2)	158.3	173.5	285.9	307.0
Operating income	96.2	101.9	160.9	165.5
Key Operating Statistics (per crude oil throughput barrel)				
Refining margin(2)	$ 15.58	$ 18.23	$ 14.50	$ 15.98
Gross profit(3)	$ 10.77	$ 11.68	$ 9.46	$ 9.57
Direct operating expenses(1)(3)	$ 3.25	$ 4.49	$ 3.43	$ 4.32

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	Three Months Ended June 30, 2009	%	2008	%	Six Months Ended June 30, 2009	%	2008	%
Refining Throughput and Production Data (bpd)								
Throughput:								
Sweet	87,610	70.8	73,876	64.8	81,319	66.5	73,460	62.9
Light/medium sour	16,245	13.1	20,451	17.9	18,477	15.1	19,265	16.5
Heavy sour	7,765	6.3	10,232	9.0	9,114	7.5	12,778	10.9
Total crude oil throughput	111,620	90.2	104,559	91.7	108,910	89.1	105,503	90.3
All other feedstocks and blendstocks	12,097	9.8	9,403	8.3	13,290	10.9	11,343	9.7
Total throughput	123,717	100.0	113,962	100.0	122,200	100.0	116,846	100.0
Production:								
Gasoline	63,170	51.0	52,028	45.2	63,745	52.1	55,845	47.4
Distillate	48,192	38.9	48,168	41.9	47,194	38.6	48,380	41.0
Other (excluding internally produced fuel)	12,529	10.1	14,883	12.9	11,338	9.3	13,675	11.6
Total refining production (excluding internally produced fuel)	123,891	100.0	115,079	100.0	122,277	100.0	117,900	100.0
Product price (dollars per gallon):								
Gasoline	$ 1.70		$ 3.12		$ 1.47		$ 2.76	
Distillate	$ 1.57		$ 3.66		$ 1.46		$ 3.26	

	Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Market Indicators (dollars per barrel)				
West Texas Intermediate (WTI) NYMEX	$ 59.79	$ 123.80	$ 51.68	$ 111.12
Crude Oil Differentials:				
WTI less WTS (light/medium sour)	1.47	4.62	1.26	4.63
WTI less WCS (heavy sour)	7.45	22.94	5.43	21.52

NYMEX Crack Spreads:				
Gasoline	12.23	9.45	10.68	7.99
Heating Oil	5.74	24.59	9.37	20.96
NYMEX 2-1-1 Crack Spread	8.99	17.02	10.03	14.48
PADD II Group 3 Basis:				
Gasoline	(1.73)	(3.61)	(1.19)	(2.56)
Ultra Low Sulfur Diesel	0.53	4.17	(0.63)	3.91
PADD II Group 3 Product Crack:				
Gasoline	10.51	5.84	9.49	5.43
Ultra Low Sulfur Diesel	6.27	28.76	8.75	24.88
PADD II Group 3 2-1-1	8.39	17.30	9.12	15.15

(1) Amounts are shown exclusive of depreciation and amortization.

(2) Refining margin is a measurement calculated as the difference between net sales and cost of product 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 product sold that we are able to sell refined products. Each of the components used in this calculation (net sales and cost of product sold (exclusive of depreciation and amortization)) are 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 usefulness as a comparative measure. In order to derive the refining margin per crude oil throughput barrel, we utilize the total dollar figures for refining margin as derived above and divide by the applicable number of crude oil throughput barrels for the period. We believe that refining margin and refining margin per crude oil throughput barrel is important to enable investors to better understand and evaluate our ongoing operating results and allow for greater transparency in the review of our overall financial, operational and economic performance.

(3) In order to derive the gross profit per crude oil throughput barrel, we utilize the total dollar figures for gross profit as derived above and divide by the applicable number of crude oil throughput barrels for the period. In order to derive the direct operating expenses per crude oil throughput barrel, we utilize the total direct operating expenses, which does not include depreciation or amortization expense, and divide by the applicable number of crude oil throughput barrels for the period.

Nitrogen Fertilizer Business Results of Operations

The tables below provide an overview of the nitrogen fertilizer business results of operations, relevant market indicators and key operating statistics:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(unaudited) (in millions)			
Nitrogen Fertilizer Business Financial Results				
Net sales	$ 55.3	$ 58.8	$ 123.1	$ 121.4
Cost of product sold(1)	8.2	6.8	16.9	15.8
Direct operating expenses(1)	21.5	19.7	43.1	39.9
Net costs associated with flood				
Depreciation and amortization	4.7	4.5	9.3	9.0
Operating income	$ 16.5	$ 23.1	$ 45.8	$ 49.2

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	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(unaudited)			
Key Operating Statistics				
Production (thousand tons):				
Ammonia (gross produced)(2)	103.3	79.5	211.3	163.2
Ammonia (net available for sale)(2)	38.9	22.2	77.8	44.3
UAN	156.1	139.1	325.8	289.2
Pet coke consumed (thousand tons)	114.3	106.0	239.6	224.2
Pet coke (cost per ton)	$ 32	$ 30	$ 34	$ 30
Sales (thousand tons)(3):				
Ammonia	27.4	19.1	75.4	43.3
UAN	161.8	138.6	304.7	296.6
Total sales	189.2	157.7	380.1	339.9
Product pricing (plant gate) (dollars per ton)(3):				
Ammonia	$ 351	$ 528	$ 365	$ 509
UAN	$ 249	$ 303	$ 280	$ 281
On-stream factor(4):				
Gasification	91.7%	82.8%	95.8%	87.3%
Ammonia	89.5%	80.0%	94.7%	85.4%
UAN	87.4%	78.3%	91.7%	82.1%
Reconciliation to net sales (dollars in millions):				
Freight in revenue	$ 5.5	$ 4.1	$ 9.6	$ 8.1
Hydrogen revenue		2.6	0.7	7.9
Sales net plant gate	49.8	52.1	112.8	105.4
Total net sales	$ 55.3	$ 58.8	$ 123.1	$ 121.4

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(unaudited)			
Market Indicators				
Natural gas NYMEX (dollars per MMBtu)	$ 3.81	$ 11.47	$ 4.13	$ 10.14
Ammonia Southern Plains (dollars per ton)	$ 308	$ 678	$ 322	$ 634
UAN Mid Cornbelt (dollars per ton)	$ 221	$ 411	$ 247	$ 391

(1) Amounts are shown exclusive of depreciation and amortization.

(2) The gross tons produced for ammonia represent the total ammonia produced, including ammonia produced that was upgraded into UAN. The net tons available for sale represent the ammonia available for sale that was not upgraded into UAN.

(3) Plant gate sales per ton represent net sales less freight and hydrogen revenue divided by product sales volume in tons in the reporting period. Plant gate pricing per ton is shown in order to provide a pricing measure that is comparable across the fertilizer industry.

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

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Three Months Ended June 30, 2009 Compared to the Three Months Ended June 30, 2008

Consolidated Results of Operations

Net Sales. Consolidated net sales were $793.3 million for the three months ended June 30, 2009 compared to $1,512.5 million for the three months ended June 30, 2008. The decrease of $719.2 million for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was primarily due to a decrease in petroleum net sales of $719.1 million that resulted from lower product prices ($771.7 million), partially offset by higher sales volumes ($52.6 million). Nitrogen fertilizer net sales decreased $3.4 million for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 primarily due to lower plant gate prices ($11.7 million), partially offset by higher overall sales volumes ($8.2 million).

Cost of Product Sold (Exclusive of Depreciation and Amortization). Consolidated cost of product sold (exclusive of depreciation and amortization) was $587.6 million for the three months ended June 30, 2009 as compared to $1,287.4 million for the three months ended June 30, 2008. The decrease of $699.8 million for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 primarily resulted from a significant decrease in raw material cost, primarily crude oil, partially offset by an increase in crude oil throughput of approximately 7,000 bpd.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Consolidated direct operating expenses (exclusive of depreciation and amortization) were $54.5 million for the three months ended June 30, 2009 as compared to $62.3 million for the three months ended June 30, 2008. This decrease of $7.8 million for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was due to a decrease in petroleum direct operating expenses of $9.7 million, partially offset by an increase of $1.8 million in nitrogen direct operating expenses. The decrease was primarily the result of net decreases in expenses associated with outside services and other direct operating expense ($6.5 million), energy and utilities ($2.2 million), property taxes ($0.8 million), operating materials ($0.6 million), catalyst ($0.4 million) and production chemicals ($0.3 million). These decreases in direct operating expenses were partially offset by net increases in expenses associated with labor ($2.2 million) and insurance ($0.9 million).

Selling, General and Administrative Expenses (Exclusive of Depreciation and Amortization). Consolidated selling, general and administrative expenses (exclusive of depreciation and amortization) were $21.8 million for the three months ended June 30, 2009 as compared to $14.8 million for the three months ended June 30, 2008. This variance was primarily the result of an increase in expenses associated with share-based compensation ($15.0 million), administrative payroll ($1.4 million), and bank charges ($0.9 million) which was partially offset by a decrease in outside services ($4.1 million) and a decline in the provision for bad debt ($3.8 million), asset write-offs ($1.5 million) and other selling, general and administrative costs ($0.9 million).

Net Costs Associated with Flood. Consolidated net costs associated with the June/July 2007 flood for the three months ended June 30, 2009 approximated $(0.1) million as compared to $3.9 million for the three months ended June 30, 2008.

Depreciation and Amortization. Consolidated depreciation and amortization was $21.1 million for the three months ended June 30, 2009 as compared to $21.1 million for the three months ended June 30, 2008.

Operating Income. Consolidated operating income was $108.4 million for the three months ended June 30, 2009 as compared to an operating income of $123.0 million for the three months ended June 30, 2008. For the three months ended June 30, 2009 as compared to the three months ended June 30, 2008, petroleum operating income decreased

$5.7 million and nitrogen fertilizer operating income decreased by $6.6 million.

Interest Expense. Consolidated interest expense for the three months ended June 30, 2009 was $11.2 million as compared to interest expense of $9.5 million for the three months ended June 30, 2008. The $1.7 million increase for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 primarily resulted from an overall increase in the borrowing rates as a result of the second amendment to our credit facility completed on December 22, 2008. This amendment resulted in an increase of interest rate margin, and LIBOR and the base rates have been set at a minimum of 3.25% and 4.25%, respectively. The increase in interest expense as a result of the amendment s impact on interest rate margin and the imposition of minimum base rates was partially offset by a decrease in average borrowings during the comparable periods.

Interest Income. Interest income was $0.7 million for the three months ended June 30, 2009 as compared to $0.6 million for the three months ended June 30, 2008.

Gain (loss) on Derivatives, net. We have determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133. For the three months ended June 30, 2009, we incurred $29.2 million in losses on derivatives. This compares to a $79.3 million net loss on derivatives for the three months ended June 30, 2008, a decrease of $50.1 million. This decrease in loss on derivatives, net for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was primarily attributable to a decrease in the realized loss on the Cash Flow Swap from $52.4 million for the three months ended June 30, 2008 compared to a realized loss of $2.7 million for the six months ended June 30, 2009, a decrease of $49.7 million. The decrease in the realized loss over the comparable period was primarily the result of lower average crack spreads for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008.

Provision for Income Taxes. Income tax expense for the three months ended June 30, 2009 was $25.5 million, or 37.4% of income before income taxes, as compared to income tax expense of $4.1 million, or 11.6% of income before income taxes, for the three months ended June 30, 2008. This increase in the effective income tax rate is primarily related to the anticipated reduction in federal and state income tax credits generated in 2009 as compared to the level of credits generated in 2008.

Net Income. For the three months ended June 30, 2009, net income increased to $42.7 million as compared to net income of $31.0 million for the three months ended June 30, 2008. Net income increased $11.7 million in the second quarter of 2009 compared to the second quarter of 2008 primarily due to a reduction of direct operating expenses, net costs associated with flood and losses on derivatives. These impacts were partially offset by increased selling, general and administrative expenses and a higher effective income tax rate.

Petroleum Business Results of Operations for the Three Months Ended June 30, 2009

Net Sales. Petroleum net sales were $740.0 million for the three months ended June 30, 2009 compared to $1,459.1 million for the three months ended June 30, 2008. The decrease of $719.1 million during the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was primarily the result of significantly lower product prices ($771.7 million) and partially offset by higher overall sales volumes ($52.6 million). Our average sales price per gallon for the three months ended June 30, 2009 for gasoline of $1.70 and distillate of $1.57 decreased by 46% and 57%, respectively, as compared to the three months ended June 30, 2008.

Cost of Product Sold (Exclusive of Depreciation and Amortization). Cost of product sold (exclusive of depreciation and amortization) 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 $581.7 million for the three months ended June 30, 2009 compared to $1,285.6 million for the three months ended June 30, 2008. The decrease of $703.9 million during the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was primarily the result of a significant decrease in crude oil prices. Our average cost per barrel of crude oil consumed for the three months ended June 30, 2009 was $53.29 compared to $119.64 for the comparable period of 2008, a decrease of 56%. Partially offsetting the decrease in raw material costs were sales volumes which increased by approximately 7% for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008. 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 a favorable FIFO inventory impact when crude oil prices increase and an unfavorable FIFO inventory impact when crude oil prices decrease. The net reduction in cost of product sold was partially offset by the decrease in the favorable FIFO impact on a quarter over quarter basis of $6.7 million. For the three months ended June 30, 2009, we had a favorable FIFO inventory impact of $67.3 million compared to a favorable FIFO inventory impact of $74.0 million for the comparable period of 2008.

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Refining margin per barrel of crude throughput decreased to $15.58 for the three months ended June 30, 2009 from $18.23 for the three months ended June 30, 2008 primarily due to the 47% decrease ($8.03 per barrel) in the average NYMEX 2-1-1 crack spread over the comparable period of 2008 and unfavorable regional differences between distillate prices in our primary marketing region (the Coffeyville supply area) and those of the NYMEX. The average distillate basis for the three months ended June 30, 2009 decreased by $3.64 per barrel to a basis of $0.53 per barrel compared to $4.17 per barrel in the comparable period of 2008. Partially offsetting the negative effects of the NYMEX 2-1-1 crack spread and distillate basis was the steep crude oil discounts achieved during the three month period ended June 30, 2009 as a result of contango in the U.S. crude oil market and improved basis between gasoline in the Coffeyville supply area and the NYMEX. The average gasoline basis increased by $1.88 per barrel to a negative basis of $1.73 per barrel compared to a negative basis of $3.61 per barrel in the comparable period of 2008.

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 and labor. Petroleum direct operating expenses (exclusive of depreciation and amortization) were $33.0 million for the three months ended June 30, 2009 compared to direct operating expenses of $42.7 million for the three months ended June 30, 2008. The decrease of $9.7 million for the three months ended June 30, 2009 compared to the three months ended June 30, 2008 was the result of decreases in expenses associated with outside services and other direct operating expenses ($6.3 million), energy and utilities ($2.9 million), property taxes ($1.2 million), operating materials ($0.6 million), production chemicals ($0.3 million) and rent ($0.2 million). These decreases in direct operating expenses were partially offset by increases in expenses associated with labor ($1.1 million) and insurance ($0.7 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for the three months ended June 30, 2009 decreased to $3.25 per barrel as compared to $4.49 per barrel for the three months ended June 30, 2008 principally due to a significant decrease in natural gas costs in the comparable periods and a decrease in outside services and other direct operating expenses as a direct result of more reliable operations of the refinery in the three months ended June 30, 2009.

Net Costs Associated with Flood. Petroleum net costs associated with flood for the three months ended June 30, 2009 approximated ($0.1) million compared to $3.4 million for the three months ended June 30, 2008.

Depreciation and Amortization. Petroleum depreciation and amortization was $16.0 million for the three months ended June 30, 2009 as compared to $16.3 million for the three months ended June 30, 2008.

Operating Income. Petroleum operating income was $96.2 million for the three months ended June 30, 2009 as compared to $101.9 million for the three months ended June 30, 2008. This decrease of $5.7 million from the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was primarily the result of a decline in the refining margin per barrel and increases in expenses associated with labor ($1.1 million) and insurance ($0.7 million). The decrease in refining margin per barrel and increase in direct operating expenses were partially offset by decreases in expenses associated with outside services and other direct operating expenses ($6.3 million), utilities and energy ($2.9 million), property taxes ($1.2 million), operating materials ($0.6 million), production chemicals ($0.3 million) and rent ($0.2 million).

Nitrogen Fertilizer Business Results of Operations for the Three Months Ended June 30, 2009

Net Sales. Nitrogen fertilizer net sales were $55.3 million for the three months ended June 30, 2009 compared to $58.8 million for the three months ended June 30, 2008. The decrease of $3.5 million for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was the result of lower average plant gate prices ($11.7 million) partially offset by higher product sales volume ($8.2 million).

In regard to product sales volumes for the three months ended June 30, 2009, our nitrogen fertilizer operations experienced an increase of 43% in ammonia sales unit volumes (8,226 tons) and an increase of 17% in UAN sales unit volumes (23,182 tons). On-stream factors (total number of hours operated divided by total hours in the reporting period) for the gasification, ammonia and UAN units were greater than on-stream factors for the comparable period. 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 three months to three months. The plant gate price provides a measure that is consistently comparable period to period. Plant gate prices for the three months ended June 30, 2009 for ammonia and UAN were lower than the comparable period of 2008 by 34% and 18%, respectively.

The demand for nitrogen fertilizer is affected by the aggregate crop planting decisions and nitrogen 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 nitrogen 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 three months ended June 30, 2009 was $8.2 million compared to $6.8 million for the three months ended June 30, 2008. The increase of $1.4 million for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was primarily the result of an increase in expenses associated with freight and distribution ($1.5 million), pet coke ($0.5 million) and excess hydrogen received from our petroleum operations ($0.4 million), partially offset by a decrease in expenses associated with the change in inventory ($1.1 million).

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, property taxes and insurance. Nitrogen direct operating expenses (exclusive of depreciation and amortization) for the three months ended June 30, 2009 were $21.5 million as compared to $19.7 million for the three months ended June 30, 2008. The increase of $1.8 million for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was primarily the result of increases in expenses associated with direct labor ($1.1 million), utilities ($0.7 million), taxes ($0.4 million) and insurance ($0.2 million). These increases in direct operating expenses were partially offset by decreases in expenses associated with catalyst ($0.4 million) and outside services and other direct operating expenses ($0.2 million).

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization increased to $4.7 million for the three months ended June 30, 2009 as compared to $4.5 million for the three months ended June 30, 2008.

Operating Income. Nitrogen fertilizer operating income was $16.5 million for the three months ended June 30, 2009 as compared to operating income of $23.1 million for the three months ended June 30, 2008. This decrease of $6.6 million for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008 was the result of decreased fertilizer prices over the comparable periods and increased direct operating expenses associated with direct labor ($1.1 million), utilities ($0.7 million), taxes ($0.4 million) and insurance ($0.2 million). These increases in direct operating expenses were partially offset by decreases in expenses associated with catalyst ($0.4 million) and outside services and other direct operating expenses ($0.2 million).

Six Months Ended June 30, 2009 Compared to the Six Months Ended June 30, 2008

Consolidated Results of Operations

Net Sales. Consolidated net sales were $1,402.7 million for the six months ended June 30, 2009 compared to $2,735.5 million for the six months ended June 30, 2008. The decrease of $1,332.8 million for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was primarily due to a decrease in petroleum net sales of $1,342.4 million that resulted from significantly lower product prices ($1,360.6 million), partially offset by slightly higher volume ($18.2 million). Nitrogen fertilizer net sales increased $1.7 million for the six months ended

June 30, 2009 as compared to the six months ended June 30, 2008 due to higher sales volumes ($11.4 million), partially offset by lower plant gate prices ($9.7 million).

Cost of Product Sold (Exclusive of Depreciation and Amortization). Consolidated cost of product sold (exclusive of depreciation and amortization) was $1,009.2 million for the six months ended June 30, 2009 as compared to $2,323.6 million for the six months ended June 30, 2008. The decrease of $1,314.4 million for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was primarily due to a significant decrease in raw material cost, primarily crude oil, partially offset by an increase in throughput. Our average cost per barrel of crude oil for the six months ended June 30, 2009 was $45.27, compared to $105.87 for the comparable period of 2008, a decrease of 57%. Sales volume of refined fuels increased approximately 2% for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Consolidated direct operating expenses (exclusive of depreciation and amortization) were $110.7 million for the six months ended June 30, 2009 as compared to $122.9 million for the six months ended June 30, 2008. This decrease of $12.2 million for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was due to a decrease in petroleum direct operating expenses of $15.4 million partially offset by an increase of $3.2 million in nitrogen direct operating expenses. The decrease was primarily related to the net decreases of outside services and other direct operating expenses ($13.6 million), energy and utilities ($3.2 million) and property taxes ($1.6 million). These decreases were partially offset by increased labor costs of ($4.4 million) and insurance ($1.7 million).

Selling, General and Administrative Expenses (Exclusive of Depreciation and Amortization). Consolidated selling, general and administrative expenses were $41.3 million for the six months ended June 30, 2009 as compared to $28.3 million for the six months ended June 30, 2008. This variance was primarily the result of an increase in expenses associated with share-based compensation ($18.4 million), administrative payroll ($3.2 million), bank charges ($2.0 million) which was partially offset by a decrease in outside services ($4.5 million) and a decline in the provision for bad debt ($3.8 million), asset write-offs ($1.5 million) and other selling, general and administrative costs ($0.8 million).

Net Costs Associated with Flood. Consolidated net costs associated with the flood for the six months ended June 30, 2009 approximated $0.1 million as compared to $9.7 for the six months ended June 30, 2008. As the Company has completed the substantial majority of the work associated with the flood, the related costs have declined for the six months ended June 30, 2009.

Depreciation and Amortization. Consolidated depreciation and amortization was $42.0 million for the six months ended June 30, 2009 as compared to $40.7 million for the six months ended June 30, 2008.

Operating Income. Consolidated operating income was $199.4 million for the six months ended June 30, 2009 as compared to operating income of $210.3 million for the six months ended June 30, 2008. For the six months ended June 30, 2009 as compared to the six months ended June 30, 2008, petroleum operating income decreased by $4.6 million and nitrogen fertilizer operating income decreased by $3.4 million.

Interest Expense. Consolidated interest expense for the six months ended June 30, 2009 was $22.7 million as compared to interest expense of $20.8 million for the six months ended June 30, 2008. The $1.9 million increase for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 primarily resulted from an overall increase in the borrowing rates as a result of the second amendment to our credit facility completed on December 22, 2008. This amendment resulted in an increase of interest rate margin, and LIBOR and the base rates have been set at a minimum of 3.25% and 4.25%, respectively. The increase in interest expense as result of the amendment s impact on interest rate margin and minimum interest rates was partially offset by a decrease in average borrowings during the comparable periods.

Interest Income. Interest income was $0.7 million for the six months ended June 30, 2009 as compared to $1.3 million for the six months ended June 30, 2008.

Loss on Derivatives, net. We have determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133. For the six months ended June 30, 2009, we incurred a $66.1 million net loss on derivatives as compared to a $127.2 million net loss on derivatives for the six months ended June 30, 2008. This significant decrease in loss on derivatives, net for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was primarily attributable to the realized losses on our Cash Flow Swap. Realized losses on the Cash Flow Swap for the six months ended June 30, 2009 and the six months ended June 30, 2008 were $18.4 million and $74.0 million, respectively. The decrease in realized losses over the comparable periods was primarily the result of lower average crack spreads for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008. The decrease in the realized losses were partially offset by an increase in the unrealized losses on our Cash Flow Swap from $29.9 million for the six months ended June 30, 2008 to $40.0 million for the six months ended June 30, 2009. Unrealized losses represent the change in the mark-to-market value on the unrealized portion of the Cash Flow Swap based on changes in the forward NYMEX crack spread that is the basis for the Cash Flow Swap. In addition to the mark-to-market value of the Cash Flow Swap, the outstanding term of the Cash Flow Swap at the end of each period also affects the impact that the changes in the forward NYMEX crack spread may have on the unrealized gain or loss. The primary cause of the remaining difference is attributable to a decline in realized losses on other agreements and interest rate swaps of $11.6 million.

Provision for Income Taxes. Income tax expense for the six months ended June 30, 2009 was approximately $37.5 million, or 33.8% of earnings before income taxes, as compared to income tax expense of approximately $10.9 million, or 17.0% of earnings before income taxes, for the six months ended June 30, 2008. The annualized effective tax rate for 2009, which was applied to earnings before income taxes for the six month period ended June 30, 2009, is higher than the comparable annualized effective tax rate for 2008, which was applied to earnings before income taxes for the six month period ended June 30, 2008, primarily due to the correlation between the amount of income tax credits which are projected to be generated in 2009 in comparison with the projected income levels. Federal and state income tax credits anticipated to be generated in 2009 are significantly lower than both the federal and state income tax credits generated in 2008.

Net Income. For the six months ended June 30, 2009, net income was $73.3 million as compared to $53.2 million for the six months ended June 30, 2008 an increase of $20.1 million or 37.8%. The increase in net income for the six months ended June 30, 2009 compared to the six months ended June 30, 2008 was primarily due to a reduction of direct operating expenses, net costs associated with flood and losses on derivatives. These impacts were partially offset by increased selling, general and administrative expenses and a higher effective income tax rate.

Petroleum Results of Operations for the Six Months Ended June 30, 2009

Net Sales. Petroleum net sales were $1,285.2 million for the six months ended June 30, 2009 compared to $2,627.6 million for the six months ended June 30, 2008. The decrease of $1,342.4 million from the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was primarily the result of significantly lower product prices ($1,360.6 million) which was partially offset by a slight increase in overall sales volume ($18.2 million). Overall sales volumes of refined fuels for the six months ended June 30, 2009 increased by approximately 1% as compared to the six months ended June 30, 2008. Our average sales price per gallon for the six months ended June 30, 2009 for gasoline of $1.47 and distillate of $1.46 decreased by 47% and 55%, respectively, as compared to the six months ended June 30, 2008.

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 $999.3 million for the six months ended June 30, 2009 compared to $2,320.6 million for the six months ended June 30, 2008. The decrease of $1,321.3 million from the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was primarily the result of a significant decrease in crude oil prices. The impact of FIFO accounting also impacted cost of products sold during the comparable periods. Our average cost per barrel of crude oil for the six months ended June 30, 2009 was $45.27, compared to $105.87 for the comparable period of 2008, a decrease of 57%. Sales volume of refined fuels increased by approximately 1% for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008. 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 a favorable FIFO inventory impact when crude oil prices increase and an unfavorable FIFO inventory impact when crude oil prices decrease. For the six months ended June 30, 2009, we reported a favorable FIFO inventory impact of $44.7 million compared to a favorable FIFO inventory impact of $92.0 million for the comparable period of 2008.

Refining margin per barrel of crude throughput decreased to $14.50 for the six months ended June 30, 2009 from $15.98 for the six months ended June 30, 2008 primarily due to the 31% decrease ($4.45 per barrel) in the average NYMEX 2-1-1 crack spread over the comparable periods and unfavorable regional differences between distillate prices in our primary marketing region (the Coffeyville supply area) and those of the NYMEX. The average distillate basis for the six months ended June 30, 2009 decreased by $4.54 per barrel to a negative basis of $0.63 per barrel compared to $3.91 per barrel in the comparable period of 2008. Partially offsetting the negative effects of the NYMEX 2-1-1 crack spread and distillate basis were the steep crude oil discounts achieved during the six month period ended June 30, 2009 as a result of a steep contango in the U.S. crude oil market and improved basis between gasoline in the Coffeyville supply area and the NYMEX. The average gasoline basis increased by $1.37 per barrel to a negative basis of $1.19 per barrel compared to a negative basis of $2.56 per barrel in the comparable period of 2008.

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, property taxes, outside services and labor. Petroleum direct operating expenses (exclusive of depreciation and amortization) were $67.6 million for the six months ended June 30, 2009 compared to direct operating expenses of $83.0 million for the six months ended June 30, 2008. The decrease of $15.4 million for the six months ended June 30, 2009 compared to the six months ended June 30, 2008 was the result of decreases in expenses associated with outside services and other direct operating expenses ($11.0 million), energy and utilities ($5.8 million), property taxes ($2.5 million) and production chemicals ($0.3 million). These decreases in direct operating expenses were partially offset by increases in expenses associated with labor ($2.8 million) and insurance ($1.4 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for the six months ended June 30, 2009 decreased to $3.43 per barrel as compared to $4.32 per barrel for the six months ended June 30, 2008 principally due to a significant decrease in natural gas costs in the comparable periods and other direct operating expenses as a direct result of more reliable operations of the refinery in the six months ended June 30, 2009.

Net Costs Associated with Flood. Petroleum net costs associated with the flood for the six months ended June 30, 2009 approximated $0.1 million as compared to $8.9 million for the six months ended June 30, 2008.

Depreciation and Amortization. Petroleum depreciation and amortization was $31.8 million for the six months ended June 30, 2009 as compared to $31.2 million for the six months ended June 30, 2008.

Operating Income. Petroleum operating income was $160.9 million for the six months ended June 30, 2009 as compared to operating income of $165.5 million for the six months ended June 30, 2008. This decrease of $4.6 million from the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was primarily the result of a decline in the refining margin per barrel and increases in expenses associated with labor ($2.8 million). The decrease in refining margin per barrel and increase in direct operating expenses were partially offset by decreases in expenses associated with net costs associated with outside services and other direct operating expenses ($11.0 million), flood ($8.8 million), energy and utilities ($5.8 million), property taxes ($2.5 million) and production chemicals ($0.3 million).

Nitrogen Fertilizer Results of Operations for the Six Months Ended June 30, 2009

Net Sales. Nitrogen fertilizer net sales were $123.1 million for the six months ended June 30, 2009 compared to $121.4 million for the six months ended June 30, 2008. The increase of $1.7 million for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was the result of higher product sales volume

($11.4 million) partially offset by lower average plant gate prices ($9.7 million).

In regard to product sales volumes for the six months ended June 30, 2009, our nitrogen fertilizer operations experienced an increase of approximately 74% in ammonia sales unit volumes (32,123 tons) and an increase of approximately 3% in UAN sales unit volumes (8,112 tons). On-stream factors (total number of hours operated divided by total hours in the reporting period) for the gasification, ammonia and UAN units were greater than on-stream factors for the comparable period. 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, 2009 for ammonia were less than plant gate prices for the comparable period of 2008 by approximately 28%. Similarly, UAN plant gate prices for the six months ending June 30, 2009 were slightly less than the comparable period of 2008.

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, freight and distribution expenses. Cost of product sold (exclusive of depreciation and amortization) for the six months ended June 30, 2009 was $16.9 million compared to $15.8 million for the six months ended June 30, 2008. The increase of $1.1 million for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was primarily the result of an increase in expenses associated with freight and distribution ($1.4 million), pet coke ($1.4 million) and excess hydrogen received from our petroleum operations ($0.4 million), partially offset by a decrease in expenses associated with the change in inventory ($2.1 million).

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, property taxes, insurance and labor. Nitrogen direct operating expenses (exclusive of depreciation and amortization) for the six months ended June 30, 2009 were $43.1 million as compared to $39.9 million for the six months ended June 30, 2008. The increase of $3.2 million for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was primarily the result of increases in expenses associated with utilities ($2.6 million), direct labor ($1.6 million), property taxes ($0.9 million), insurance ($0.3 million), equipment rental ($0.2 million) and refractory brick amortization ($0.2 million). These increases in direct operating expenses were partially offset by a reduction in expenses associated with outside services and other direct operating expenses ($2.6 million).

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization increased to $9.3 million for the six months ended June 30, 2009 as compared to $9.0 million for the six months ended June 30, 2008.

Operating Income. Nitrogen fertilizer operating income was $45.8 million for the six months ended June 30, 2009 as compared to $49.2 million for the six months ended June 30, 2008. This decrease of $3.4 million for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was the result of increased sales volumes ($11.4 million), coupled with lower plant gate prices for both ammonia and UAN ($9.7 million). More than offsetting the positive effects of the sales variance were increased direct operating expenses primarily the result of increases in expenses associated with utilities ($2.6 million), direct labor ($1.6 million), property taxes ($0.9 million), insurance ($0.3 million), equipment rental ($0.2 million) and refractory brick amortization ($0.2 million). These increases in direct operating expenses were partially offset by a reduction in expenses associated with outside services and other direct operating expenses ($2.6 million).

Liquidity and Capital Resources

Our primary sources of liquidity currently consist of cash generated from our operating activities, existing cash and cash equivalent balances and our existing revolving credit facility. Our ability to generate sufficient cash flows from our operating activities will continue to be primarily dependent on producing or purchasing, and selling, sufficient quantities of refined products and nitrogen fertilizer products at margins sufficient to cover fixed and variable expenses.

We believe that our cash flows from operations and existing cash and cash equivalent balances, together with borrowings under our existing revolving credit facility as necessary, will be sufficient to satisfy the anticipated cash requirements associated with our existing operations for at least the next 12 months. However, our future capital expenditures and other cash requirements could be higher than we currently expect as a result of various factors. Additionally, our ability to generate sufficient cash from our operating activities depends on our future performance, which is subject to general economic, political, financial, competitive, and other factors beyond our control.

Cash Balance and Other Liquidity

As of June 30, 2009, we had cash and cash equivalents of $73.3 million. As of June 30, 2009 and July 31, 2009, we had no amounts outstanding under our revolving credit facility and aggregate availability of $116.1 million under our revolving credit facility. At July 31, 2009, we had cash and cash equivalents of $58.4 million.

At June 30, 2009, funded long-term debt, including current maturities, totaled $481.9 million of tranche D term loans. Other commitments at June 30, 2009 included a $60.0 million funded letter of credit facility and a $150.0 million revolving credit facility. As of December 31, 2008, the commitment outstanding on the revolving credit facility was $49.9 million, including $0 million in borrowings, $3.3 million in letters of credit in support of certain environmental obligations, and $46.6 million in letters of credit to secure transportation services for crude oil. As of July 31, 2009, total outstanding debt under our credit facility was $480.7 million, which was all term debt.

Working capital at June 30, 2009 was $247.3 million, consisting of $423.8 million in current assets and $176.5 million in current liabilities. Working capital at December 31, 2008 was $128.5 million, consisting of $373.4 million in current assets and $244.9 million in current liabilities.

Credit Facility

CRLLC s credit facility currently consists of tranche D term loans with an outstanding balance of $481.9 million at June 30, 2009, a $150.0 million revolving credit facility, and a funded letter of credit facility of $60.0 million issued in support of the Cash Flow Swap. Prior to June 1, 2009, the funded letter of credit in support of the Cash Flow Swap totaled $150.0 million.

The $481.9 million of tranche D term loans outstanding as of June 30, 2009 are subject to quarterly principal amortization payments of 0.25% of the outstanding balance, 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.

The revolving credit 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. Outstanding letters of credit reduce the amount available under our revolving credit facility. The revolving loan commitment expires on December 28, 2012. CRLLC 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 June 30, 2009, we had available $116.1 million under the revolving credit facility.

The $60.0 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, CRLLC 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.

On December 22, 2008, CRLLC entered into a second amendment to its credit facility. The amendment was entered into, among other things, to amend the definition of consolidated adjusted EBITDA to add a FIFO adjustment which applies for the year ending December 31, 2008 through the quarter ending September 30, 2009. This FIFO adjustment will be used for the purpose of testing compliance with the financial covenants under the

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credit facility until the quarter ending June 30, 2010. CRLLC sought and obtained the amendment due to the dramatic decrease in the price of crude oil in the fourth quarter of 2008 and the effect that such crude oil price decrease would have had on the measurement of the financial ratios under the credit facility. As part of the amendment, CRLLC s interest rate margin increased by 2.50%, and LIBOR and the base rate have been set at a minimum of 3.25% and 4.25%, respectively.

After giving effect to the second amendment, 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 4.50%, or, at CRLLC s option, (b) LIBOR plus 5.50% (with step-downs to the prime rate/federal funds rate plus 4.25% or 4.00% or LIBOR plus 5.25% or 5.50%, respectively, upon achievement of certain rating conditions).

Revolving credit 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 4.50%, or, at CRLLC s option, (b) LIBOR plus 5.50% (with step-downs to the prime rate/federal funds rate plus 4.25% or 4.00% or LIBOR plus 5.25% or 5.00%, respectively, upon achievement of certain rating conditions). Revolving credit lenders receive commitment fees equal to the amount of undrawn revolving credit loans times 0.5% per annum.

Letters of credit issued under the $75.0 million sub-limit available under the revolving credit facility are subject to a fee equal to the applicable margin on revolving LIBOR loans owing to all revolving credit 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. CRLLC 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.

The amendment provides for more restrictive requirements. Among other things, CRLLC is subject to more stringent obligations under certain circumstances to make mandatory prepayments of loans. In addition, the amendment increased the percentage of excess cash flow during any fiscal year that must be used to prepay the loans and eliminated a basket which previously allowed CRLLC to pay dividends of up to $35.0 million per year.

The credit facility requires CRLLC to prepay outstanding loans, subject to certain exceptions. Some of the requirements, among other things, are as follows:

100% of asset sale proceeds must be used to repay outstanding loans;

100% of the cash proceeds from the incurrence of specified debt obligations must be used to prepay outstanding loans; and

100% of consolidated excess cash flow less 100% of voluntary prepayments made during the fiscal year must be used to prepay outstanding loans; provided that with respect to any fiscal year commencing with fiscal 2008, this percentage will be reduced to 75% if the total leverage ratio at the end of such fiscal year is less than 1.50:1.00 or 50% if the total leverage ratio as of the end of such fiscal year is less than 1.00:1.00.

Under the terms of our credit facility, the interest margin paid is subject to change based on changes in our leverage ratio and changes in our credit rating by either Standard & Poor s (S&P) or Moody s. S&P s announcement in February

2009 to place the Company on negative outlook resulted in an increase in our interest rate of 0.25% on amounts borrowed under our term loan facility, revolving credit facility and the $60.0 million funded letter of credit facility.

The credit facility contains customary covenants, which, among other things, restrict, subject to certain exceptions, the ability of CRLLC 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 CRLLC may not enter into commodity agreements if, after giving effect thereto, the exposure under all such commodity agreements exceeds 75% of Actual Production (the 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, CRLLC may not enter into material amendments related to any material rights under the Cash Flow Swap or the Partnership s partnership agreement without the prior written approval of the requisite 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 CRLLC to maintain certain financial ratios as follows:

Fiscal Quarter Ending	**Minimum Interest Coverage Ratio**	**Maximum Leverage Ratio**
March 31, 2009 December 31, 2009	3.75:1.00	2.25:1.00
March 31, 2010 and thereafter	3.75:1.00	2.00:1.00

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 on a four quarter basis. In general, under the terms of our credit facility, consolidated adjusted EBITDA is calculated by adding on a consolidated basis, consolidated net income, consolidated interest expense, income tax expense, depreciation and amortization, other non-cash items, 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, major scheduled turnaround expenses and for purposes of computing the financial ratios (and compliance therewith), the FIFO adjustment, and then subtracting certain items that increase consolidated net income. We were in compliance with our covenants under the credit facility as of June 30, 2009.

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 financial measure 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

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to cash flows as a measure of liquidity. Consolidated adjusted EBITDA is calculated under the credit facility as follows:

	For the Twelve Months Ended June 30, 2009	2008
	(unaudited) (in millions)	
Consolidated Financial Results		
Net income	$ 184.0	$ 39.9
Plus:		
Depreciation and amortization	83.5	76.9
Interest expense	42.2	54.3
Income tax expense	90.5	63.4
Funded letters of credit expenses and interest rate swap not included in interest expense	12.1	4.8
Unrealized (gain) or loss on derivatives, net	(241.9)	(44.7)
Non-cash compensation expense for equity awards	(4.3)	16.6
(Gain) or loss on disposition of fixed assets	4.2	1.7
Unusual or nonrecurring charges	0.5	17.2
Property tax increases due to abatement non-renewal	12.5	4.9
FIFO adjustment favorable (unfavorable)(1)	138.6	
Loss on extinguishment of debt	10.7	1.3
Minority interest in subsidiaries		
Management fees		10.6
Major scheduled turnaround	3.3	(0.4)
Goodwill impairment	42.8	
Consolidated adjusted EBITDA	$ 378.7	$ 246.5

(1) The amendment to the credit facility entered into on December 22, 2008 amended the definition of consolidated adjusted EBITDA to add a FIFO adjustment. This amendment to the definition first applied for the year ending December 31, 2008 and will apply through the quarter ending September 30, 2009.

In addition to the financial covenants previously mentioned, the credit facility restricts the capital expenditures of CRLLC and its subsidiaries to $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 year 2009 if CRLLC 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.

The credit facility is subject to an intercreditor agreement among the lenders and the Cash Flow Swap provider, which deals with, among other things, priority of liens, payments and proceeds of sale of collateral.

Capital Spending

Our total capital expenditures for the quarter ending June 30, 2009 were $8.7 million of which approximately $6.6 million was spent in the petroleum business and $2.1 million in our nitrogen fertilizer business. For the six months ended June 30, 2009, total capital expenditures were approximately $24.6 million which consisted of $14.0 million for the petroleum business and $9.6 million for our fertilizer business.

Our more recent forecast for consolidated projected capital expenditures for 2009 approximates $71.9 million. These capital expenditures consist of $49.2 million for our petroleum business, $20.1 million for our fertilizer business, and approximately $2.6 million for corporate purposes.

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, such as for planned turnarounds and other maintenance, is required to maintain safe and reliable operations or to comply with environmental and health and safety regulations. Our non-discretionary capital expenditures for the six months ended June 30, 2009 totaled $13.4 million, of which approximately $12.2 million was spent in our petroleum business and $1.2 million in our nitrogen fertilizer business. We estimate that the total non-discretionary capital spending needs, including major scheduled turnaround expenses, of our refinery and the nitrogen fertilizer facilities will be approximately $50.2 million in the aggregate for 2009. This estimate includes, among other items, the capital costs necessary to comply with environmental regulations, including Tier II gasoline standards.

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. We have spent approximately $9.7 million on discretionary capital expenditures for the six months ended June 30, 2009. Based upon our most recent forecast, we estimate that we will spend approximately $9.4 million for the remainder of 2009 related to discretionary capital projects.

Cash Flows

The following table sets forth our cash flows for the periods indicated below (in millions):

	Six Months Ended June 30,	
	2009	2008
	(unaudited)	
Net cash provided by (used in):		
Operating activities	$ 91.5	$ 23.3

Investing activities	(24.6)	(49.6)
Financing activities	(2.5)	16.4
Net increase (decrease) in cash and cash equivalents	$ 64.4	$ (9.9)

Cash Flows Provided by Operating Activities

Net cash flows from operating activities for the six months ended June 30, 2009 was $91.5 million. The positive cash flow from operating activities generated over this period was primarily driven by $73.3 million of net income, favorable changes in other working capital, other assets and liabilities which were partially offset by unfavorable changes in trade 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 derivative financial instruments in general and, more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133. Therefore, the net income for the six months ended June 30, 2009 included both the realized losses and the unrealized losses on the Cash Flow Swap. The Cash Flow Swap had a remaining term of one year as of June 30, 2009 and the NYMEX crack spread, the basis for the underlying swaps, increased, thus the unrealized losses on the Cash Flow Swap decreased our net income over this period. Significant changes in other working capital included $9.0 million of related prepaid expenses and other current assets, $34.5 million of accrued income taxes and $11.8 million of additional insurance proceeds. Significant uses of cash for the six months ended June 30, 2009 included the pay down of the J. Aron deferral totaling approximately $62.4 million and the payment of approximately $18.4 million for realized losses on the Cash Flow Swap. These changes in the payable to swap counterparty were partially offset by a $58.4 million increase in the realized and unrealized loss for the six months ended June 30, 2009. Trade working capital for the six months ended June 30, 2009 resulted in a use of cash of $114.3 million. For the six months ended June 30, 2009, accounts receivable increased $35.0 million, inventory increased by $74.3 million and accounts payable decreased by $5.0 million.

Net cash flows from operating activities for the six months ended June 30, 2008 was $23.3 million. The positive cash flow from operating activities generated over the six months ended June 30, 2008 was primarily driven by net income, favorable changes in other working capital which were partially offset by unfavorable changes in trade working capital and 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. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133. Therefore, the net income for the six months ended June 30, 2008 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, 2008 (approximately two years), the unrealized losses on the Cash Flow Swap significantly decreased our net income over this period. The impact of the realized and unrealized losses on the Cash Flow Swap is apparent in the $67.7 million increase in the payable to swap counterparty. Trade working capital for the six months ended June 30, 2008 resulted in a use of cash of $131.0 million. For the six months ended June 30, 2008, accounts receivable increased $54.5 million, inventory increased by $71.8 million and accounts payable decreased by $4.7 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities for the six months ended June 30, 2009 was $24.6 million compared to $49.6 million for the six months ended June 30, 2008. The decrease in investing activities for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 was the result of decreased capital expenditures.

Cash Flows Used in Financing Activities

Net cash used for financing activities for the six months ended June 30, 2009 was $2.5 million as compared to net cash provided by financing activities of $16.4 million for the six months ended June 30, 2008. During the six months ended June 30, 2009, we paid $2.4 million of scheduled principal payments. During the six months ended June 30, 2008, we paid $2.4 million of scheduled principal payments, $1.7 million of initial public offering costs, and $0.9 million related to capital lease obligations. During the six months ended June 30, 2008 the primary source of cash from financing activities related to revolving debt borrowings net of payments of $21.5 million.

Working Capital

Working capital at June 30, 2009 was $247.3 million, consisting of $423.8 million in current assets and $176.5 million in current liabilities. Working capital at December 31, 2008 was $128.5 million, consisting of

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$373.4 million in current assets and $244.9 million in current liabilities. In addition, we had available borrowing capacity under our revolving credit facility of $116.1 million at June 30, 2009.

Letters of Credit

Our revolving credit facility provides for the issuance of letters of credit. At June 30, 2009, there were $33.9 million of irrevocable letters of credit outstanding, including $3.3 million in support of certain environmental obligations and $30.6 million to secure transportation services for crude oil.

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, 2009 relating to long-term debt, operating leases, capital lease obligation, unconditional purchase obligations and other specified capital and commercial commitments for the period following June 30, 2009 and thereafter.

	Payments Due by Period (unaudited) (in millions)						
	Total	2009	2010	2011	2012	2013	Thereafter
Contractual Obligations							
Long-term debt(1)	$ 481.9	$ 2.4	$ 4.8	$ 4.7	$ 4.7	$ 465.3	$
Operating leases(2)	14.3	2.3	4.4	3.0	2.6	1.7	0.3
Capital lease obligation(3)	4.4		4.4				
Unconditional purchase obligations(4)(5)	317.2	15.7	32.5	31.0	28.1	28.1	181.8
Environmental liabilities(6)	6.9	2.1	1.0	0.5	0.3	0.3	2.7
Funded letter of credit fees(7)	3.5	1.8	1.7				
Interest payments(8)	174.3	21.5	42.3	41.8	41.5	27.2	
Total	$ 1,002.5	$ 45.8	$ 91.1	$ 81.0	$ 77.2	$ 522.6	$ 184.8
Other Commercial Commitments							
Standby letters of credit(9)	$ 33.9	$	$	$	$	$	$

(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. As of June 30, 2009, $481.9 million was outstanding under our credit facility.

(2) The nitrogen fertilizer business leases various facilities and equipment, primarily railcars, under non-cancelable operating leases for various periods.

(3) This amount represents a capital lease for real property used for corporate purposes.

(4) 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.

(5) This amount excludes approximately $510 million potentially payable under petroleum transportation service agreements with TransCanada Keystone Pipeline, LP (TransCanada), pursuant to which CRRM would receive a volume amount of at least 25,000 barrels per day with a delivery point at Cushing, Oklahoma for a term of 10 years on a new pipeline system being constructed by TransCanada. This amount would be payable ratably over the 10 year service period under the agreements, such period to begin upon commencement of services under the new pipeline system. Based on information currently available to us, we believe commencement of services would begin in the first quarter of 2011. The Company is currently undertaking action to dispute the validity of the petroleum transportation service agreements. The Company cannot provide any assurance that the petroleum transportation service agreements will be found to be invalid.

(6) Environmental liabilities represents (1) 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 and (2) our estimated remaining costs to address environmental contamination resulting from a reported release of UAN in 2005 pursuant to the State of Kansas Voluntary Cleaning and Redevelopment Program. We also have other environmental liabilities which are not contractual obligations but which would be necessary for our continued operations.

(7) 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.

(8) Interest payments are based on interest rates in effect at June 30, 2009 and assume contractual amortization payments.

(9) Standby letters of credit include $3.3 million of letters of credit issued in connection with environmental liabilitie and $30.6 million in letters of credit to secure transportation services for crude oil.

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. Our ability to refinance our indebtedness is also subject to the availability of the credit markets, which in recent periods have been extremely volatile. 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. Our business may not generate sufficient cash flow from operations, and future borrowings may not be available to us under our credit facility (or other credit facilities we may enter into in the future) 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.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of June 30, 2009.

Recent Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board (FASB) issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)*. SFAS 167 is intended to improve financial reporting by enterprises involved with variable interest entities. SFAS 167 is effective as of the beginning of the entity s first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period, and for interim and annual reporting periods thereafter. The Company is currently evaluating the impact of the standard, but does not believe it will have a material impact on the Company s financial position or results of operations.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*, which became effective June 15, 2009 and is to be applied for all interim and annual financial periods ending thereafter. SFAS 165 is intended to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which the Company has evaluated subsequent events and the basis for that date that is, whether that date represents the date the financial statements were issued or were available to be issued. As required, the Company adopted this statement as of June 15, 2009. As a result of this adoption, the Company provided additional disclosures regarding the evaluation of subsequent events and the date through which that evaluation took place. There is no impact on the financial position or results of operations of the Company as a result of this adoption.

In April 2009, the FASB issued FASB Staff Position (FSP) No. 157-4, *Determining Fair Value when the Volume and Level of Activity for the Asset or Liability have Significantly Decreased and Identifying Transactions That Are Not Orderly*. The FSP provides guidance for determining the fair value of an asset or liability when there has been a significant decrease in market activity. In addition, the FSP requires additional disclosures regarding the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any during annual or interim periods. As required, the Company adopted this statement as of June 15, 2009. Based upon the Company s assets and liabilities currently subject to the provisions of SFAS No. 157,

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Fair Value Measurements, there is no impact on the Company s financial position, results of operations or note disclosures as a result of this adoption.

In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, which became effective January 1, 2009 and is to be applied retrospectively. Under the FSP, unvested share-based payment awards, which receive non-forfeitable dividend rights, or dividend equivalents, are considered participating securities and are now required to be included in computing earnings per share under the two class method. As required, we adopted this statement as of January 1, 2009. Based upon the nature of our share-based payment awards, it has been determined that these awards are not participating securities and, therefore, the FSP currently has no impact on our earnings per share calculations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133.* This statement changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedge items affect an entity s financial position, net earnings, and cash flows. As required, the Company adopted this statement as of January 1, 2009. As a result of the adoption, we provided additional disclosures regarding our derivative instruments in the notes to the condensed consolidated financial statements. There is no impact on our financial position or results of operations as a result of this adoption.

In February 2008, the FASB issued FSP 157-2 which defers the effective date of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in an entity s financial statements on a recurring basis (at least annually). As required, we adopted SFAS 157 as of January 1, 2009. The adoption of SFAS 157 did not impact our financial position or results of operations.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51.* SFAS 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing noncontrolling interests. All other requirements of SFAS 160 must be applied prospectively. We adopted SFAS 160 effective January 1, 2009, and as a result have classified the noncontrolling interest (previously minority interest) as a separate component of equity for all periods presented.

Critical Accounting Policies

Our critical accounting policies are disclosed in the Critical Accounting Policies section of our Annual Report on Form 10-K for the year ended December 31, 2008. No modifications have been made to our critical accounting policies.

Item 3. *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. Information about market risks for the six months ended June 30, 2009 does not differ materially from that discussed under Part II Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2008 . We are exposed to market pricing for all of the products sold in the future both at our petroleum business and the nitrogen fertilizer business, as all of the products manufactured in both businesses are commodities.

As of June 30, 2009, all $481.9 million of outstanding debt under our credit facility was at floating rates; accordingly, an increase of 1.0% in our interest rate would result in an increase in our interest expense of approximately $4.8 million per year. None of our market risk sensitive instruments are held for trading.

Our earnings and cash flows and estimates of future cash flows are sensitive to changes in energy prices. The prices of crude oil and refined products have fluctuated substantially in recent years. These prices depend on many factors, including the overall demand for crude oil and refined products, which in turn depend on, among other factors, general economic conditions, the level of foreign and domestic production of crude oil and refined products, the availability of imports of crude oil and refined products, the marketing of alternative and competing fuels, the extent of government regulations and global market dynamics. The prices we receive for refined products are also affected by factors such as local market conditions and the level of operations of other refineries in our markets. The prices at which we can sell gasoline and other refined products are strongly influenced by the price of crude oil. Generally, an increase or decrease in the price of crude oil results in a corresponding increase or decrease in the price of gasoline and other refined products. The timing of the relative movement of the prices, however, can impact profit margins, which could significantly affect our earnings and cash flows.

Item 4. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

Our management, under the direction of our Chief Executive Officer and Chief Financial Officer, evaluated as of June 30, 2009 the effectiveness of our disclosure controls and procedures as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act). Based upon and as of the date of that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective, at a reasonable assurance level, to ensure that information required to be disclosed in the reports we file and submit under the Exchange Act is recorded, processed, summarized and reported as and when required and is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. It should be noted that any system of disclosure controls and procedures, however well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the system are met. In addition, the design of any system of disclosure controls and procedures is based in part upon assumptions about the likelihood of future events. Due to these and other inherent limitations of any such system, there can be no assurance that any design will always succeed in achieving its stated goals under all potential future conditions.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting required by Rule 13a-15 of the Exchange Act that occurred during the fiscal quarter ended June 30, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The Company has previously disclosed in Part I Item 4 of its Form 10-Q for the quarter ended September 30, 2008 and in Item 9A of the Company s Annual Report on Form 10-K that as of March 31, 2008, the Company discovered material weaknesses in its internal controls over accounting for the cost of crude oil. As previously disclosed, controls necessary to remediate the material weaknesses were in place by September 30, 2008, and all testing efforts to fully remediate the material weaknesses were conducted and completed in the fourth quarter of 2008. As previously disclosed, as of December 31, 2008, the material weaknesses related to accounting for the cost of crude oil were fully remediated and the Company had no material weaknesses in its internal controls. Accordingly, during the third quarter of 2008, we made changes to our internal control over financial reporting that materially affected or were reasonably likely to materially affect our internal controls over financial reporting, and during the fourth quarter of 2008 we conducted and completed the testing of these changes to our internal controls. The changes adopted that materially affected the internal control over financial reporting were the additional layers of accounting review that were added with respect to our crude oil cost accounting. Additional layers of business review were also added in conjunction with the accounting review of the computation of our crude oil costs.

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Part II. Other Information

Item 1. *Legal Proceedings*

The following supplements and amends our discussion set forth under Item 3 Legal Proceedings in our Annual Report on Form 10-K for the year ended December 31, 2008.

See Note 11 (Commitments and Contingent Liabilities) to Part I, Item I of this Form 10-Q for a description of the Samson litigation contained in Litigation and for a description of the Consent Decree contained in Environmental, Health, and Safety (EHS) Matters .

Item 1A. *Risk Factors*

There are no material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2008 under Part I Item 1A. Risk Factors.

Item 4. *Submission of Matters to a Vote of Security Holders*

At the annual meeting of the stockholders of the Company held on April 28, 2009, the following matters set forth in our Proxy Statement dated March 27, 2009, which was filed with the SEC pursuant to Regulation 14A under the Exchange Act, were voted upon with the results indicated below.

1. The nominees listed below were elected as directors with the respective votes set forth opposite each nominee s name:

Director	Votes For	Votes Withheld
C. Scott Hobbs	83,365,826	538,009
John J. Lipinski	72,880,491	11,023,344
Scott L. Lebovitz	72,805,153	11,098,682
Regis B. Lippert	72,354,433	10,549,402
George E. Matelich	72,610,025	11,293,810
Steve A. Nordaker	82,920,471	983,364
Stanley de J. Osborne	72,806,828	11,097,007
Kenneth A. Pontarelli	72,606,562	11,297,273
Mark E. Tomkins	82,920,434	983,401

2. A proposal ratifying the appointment by the Company s Audit Committee of KPMG LLP as the independent registered public accounting firm of the Company for the fiscal year ending December 31, 2009 was approved, with 83,817,228 votes cast FOR, 81,201 votes cast AGAINST, and 5,406 abstentions.

Item 6. *Exhibits*

Number	Exhibit Title

10.1	Employment Agreement, dated April 1, 2009, by and between CVR Energy, Inc. and Edward Morgan.
10.2	Amendment to the ISDA Master Agreement and schedule thereto, dated as of May 29, 2009, by and between J. Aron & Company and Coffeyville Resources, LLC.
10.3	Second Amendment to the Crude Oil Supply Agreement, dated July 7, 2009, by and between Coffeyville Resources Refining & Marketing, LLC and Vitol Inc.
31.1	Certification of the Company s Chief Executive Officer pursuant to Rule 13a-14(a) or 15(d)-14(a) under the Securities Exchange Act.
31.2	Certification of the Company s Chief Financial Officer pursuant to Rule 13a-14(a) or 15(d)-14(a) under the Securities Exchange Act.
32.1	Certification of the Company s Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of the Company s Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

PLEASE NOTE: Pursuant to the rules and regulations of the Securities and Exchange Commission, we have filed or incorporated by reference the agreements referenced above as exhibits to this quarterly report on Form 10-Q. The agreements have been filed to provide investors with information regarding their respective terms. The agreements are not intended to provide any other factual information about the Company or its business or operations. In particular, the assertions embodied in any representations, warranties and covenants contained in the agreements may be subject to qualifications with respect to knowledge and materiality different from those applicable to investors and may be qualified by information in confidential disclosure schedules not included with the exhibits. These disclosure schedules may contain information that modifies, qualifies and creates exceptions to the representations, warranties and covenants set forth in the agreements. Moreover, certain representations, warranties and covenants in the agreements may have been used for the purpose of allocating risk between the parties, rather than establishing matters as facts. In addition, information concerning the subject matter of the representations, warranties and covenants may have changed after the date of the respective agreement, which subsequent information may or may not be fully reflected in the Company s public disclosures. Accordingly, investors should not rely on the representations, warranties and covenants in the agreements as characterizations of the actual state of facts about the Company or its business or operations on the date hereof.

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SIGNATURES

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

CVR Energy, Inc.

By: /s/ John J. Lipinski

Chief Executive Officer
(Principal Executive Officer)

August 7, 2009

By: /s/ Edward Morgan

Chief Financial Officer
(Principal Financial Officer)

August 7, 2009