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

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2010

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

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

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

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

There were 86,343,102 shares of the registrant's common stock outstanding at August 4, 2010.

CVR ENERGY, INC. AND SUBSIDIARIES

INDEX TO QUARTERLY REPORT ON FORM 10-Q
For The Quarter Ended June 30, 2010

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 distillate. 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.

Backwardation market — Market situation in which futures prices are lower in succeeding delivery months. Also known as an inverted market. The opposite of contango.

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.

Coker unit — A refinery unit that utilizes the lowest value component of crude oil remaining after all higher value products are removed, further breaks down the component into more valuable products and converts the rest into pet coke.

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 market — Market situation in which prices for future delivery are higher than the current or spot market price of the commodity. The opposite of backwardation.

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 distillate.

Distillates — Primarily diesel fuel, kerosene and jet fuel.

Ethanol — A clear, colorless, flammable oxygenated hydrocarbon. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. It is used in the United States as a gasoline octane enhancer and oxygenate.

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.

MMBtu — One million British thermal units or Btu is 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 both feedstocks used in the manufacture of refined fuels and are products of the refining process. 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.

Spot market — A market in which commodities are bought and sold for cash and delivered immediately.

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 or transported on a pipeline.

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 — 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 degrees 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 oil and other feedstocks.

PART I. FINANCIAL INFORMATION

ITEM 1. ***FINANCIAL STATEMENTS***

CVR ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2010 (unaudited)	December 31, 2009
	(in thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 63,269	$ 36,905
Accounts receivable, net of allowance for doubtful accounts of $4,285 and $4,772, respectively	84,451	45,729
Inventories	251,622	274,838
Prepaid expenses and other current assets	22,202	26,141
Income tax receivable	15,610	20,858
Deferred income taxes	14,578	21,505
Total current assets	451,732	425,976
Property, plant, and equipment, net of accumulated depreciation	1,109,273	1,137,910
Intangible assets, net	361	377
Goodwill	40,969	40,969
Deferred financing costs, net	13,022	3,485
Insurance receivable	1,000	1,000
Other long-term assets	4,334	4,777
Total assets	$ 1,620,691	$ 1,614,494
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ —	$ 4,777
Note payable and capital lease obligations	4,841	11,774
Accounts payable	117,785	106,471
Personnel accruals	22,512	14,916
Accrued taxes other than income taxes	19,336	15,904
Deferred revenue	1,133	10,289
Other current liabilities	20,713	26,493
Total current liabilities	186,320	190,624
Long-term liabilities:		
Long-term debt, net of current portion	496,090	474,726
Accrued environmental liabilities, net of current portion	2,844	2,828
Deferred income taxes	275,743	278,008
Other long-term liabilities	3,748	3,893
Total long-term liabilities	778,425	759,455
Commitments and contingencies		
Equity:		
CVR stockholders' equity:		
Common Stock $0.01 par value per share, 350,000,000 shares authorized, 86,354,508 and 86,344,508 shares issued, respectively	864	863
Additional paid-in-capital	448,988	446,263
Retained earnings	195,578	206,789
Treasury stock, 11,406 and 15,271 shares, respectively, at cost	(84)	(100)
Total CVR stockholders' equity	645,346	653,815
Noncontrolling interest	10,600	10,600
Total equity	655,946	664,415
Total liabilities and equity	$ 1,620,691	$ 1,614,494

See accompanying notes to the condensed consolidated financial statements.

CVR ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited) (in thousands, except share data)			
Net sales	$ 1,005,898	$ 793,304	$ 1,900,410	$ 1,402,699
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	891,652	587,635	1,694,542	1,009,240
Direct operating expenses (exclusive of depreciation and amortization)	62,479	54,447	123,041	110,681
Selling, general and administrative expenses (exclusive of depreciation and amortization)	10,793	21,772	32,187	41,278
Net costs associated with flood	—	(101)	—	80
Depreciation and amortization	21,553	21,107	42,813	42,016
Total operating costs and expenses	986,477	684,860	1,892,583	1,203,295
Operating income	19,421	108,444	7,827	199,404
Other income (expense):				
Interest expense and other financing costs	(12,766)	(11,191)	(22,688)	(22,661)
Interest income	643	653	1,059	667
Gain (loss) on derivatives, net	7,339	(29,233)	8,829	(66,094)
Loss on extinguishment of debt	(14,552)	(677)	(15,052)	(677)
Other income, net	642	173	684	198
Total other income (expense)	(18,694)	(40,275)	(27,168)	(88,567)
Income (loss) before income tax expense (benefit)	727	68,169	(19,341)	110,837
Income tax expense (benefit)	(425)	25,500	(8,130)	37,507
Net income (loss)	$ 1,152	$ 42,669	$ (11,211)	$ 73,330
Basic earnings (loss) per share	$ 0.01	$ 0.49	$ (0.13)	$ 0.85
Diluted earnings (loss) per share	$ 0.01	$ 0.49	$ (0.13)	$ 0.85
Weighted-average common shares outstanding:				
Basic	86,336,125	86,244,152	86,332,700	86,243,949
Diluted	86,506,590	86,333,349	86,332,700	86,327,911

See accompanying notes to the condensed consolidated financial statements.

CVR ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited) (in thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (11,211)	$ 73,330
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	42,813	42,016
Provision for doubtful accounts	(487)	122
Amortization of deferred financing costs	1,517	1,077
Amortization of original issue discount	110	—
Deferred income taxes	4,662	3,995
Loss on disposition of assets	1,661	19
Loss on extinguishment of debt	15,052	677
Share-based compensation	4,434	9,479
Unrealized (gain) loss on derivatives	(4,734)	37,797
Changes in assets and liabilities:		
Restricted cash	—	34,560
Accounts receivable	(38,235)	(34,993)
Inventories	23,216	(74,316)
Prepaid expenses and other current assets	(10,196)	9,016
Insurance proceeds from flood	—	11,756
Other long-term assets	102	2,805
Accounts payable	12,660	(5,032)
Accrued income taxes	5,248	34,503
Deferred revenue	(9,156)	(2,940)
Other current liabilities	8,339	6,761
Payable to swap counterparty	—	(62,314)
Accrued environmental liabilities	16	(703)
Other long-term liabilities	(145)	3,856
Net cash provided by operating activities	45,666	91,471
Cash flows from investing activities:		
Capital expenditures	(16,826)	(24,575)
Net cash used in investing activities	(16,826)	(24,575)
Cash flows from financing activities:		
Revolving debt payments	(60,000)	(72,700)
Revolving debt borrowings	60,000	72,700
Proceeds net of original issue discount on issuance of senior notes	485,853	—
Principal payments on term debt	(479,503)	(2,418)
Payment of financing costs	(8,737)	—
Payment of capital lease obligation	(40)	(60)
Payment of treasury stock	(49)	—
Net cash used in financing activities	(2,476)	(2,478)
Net increase in cash and cash equivalents	26,364	64,418
Cash and cash equivalents, beginning of period	36,905	8,923
Cash and cash equivalents, end of period	$ 63,269	$ 73,341
Supplemental disclosures:		
Cash paid for income taxes, net of refunds (received)	$ (18,040)	$ (990)
Cash paid for interest, net of capitalized interest of $1,647 and $802 in 2010 and 2009, respectively	20,132	19,642
Non-cash investing and financing activities:		
Accrual of construction in progress additions	(1,346)	(4,956)
Reduction of senior notes for underwriting discount and financing costs	10,127	—

See accompanying notes to the condensed consolidated financial statements.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
JUNE 30, 2010
(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 of high value transportation fuels 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, 2010 and December 31, 2009, approximately 64% 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 then 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 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 Condensed Consolidated Balance Sheets at June 30, 2010 and December 31, 2009.

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 first priority 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 first priority credit facility.

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, 2010, 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, since an initial private or public offering of the Partnership was 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 recorded 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, 2009 audited consolidated financial statements and notes thereto included in CVR's Annual Report on Form 10-K for the year ended December 31, 2009, which was filed with the SEC on March 12, 2010.

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, 2010 and December 31, 2009, the results of operations for the three and six months ended June 30, 2010 and 2009, and the cash flows for the six months ended June 30, 2010 and 2009. Certain prior year amounts have been reclassified to conform to current year presentation.

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, 2010 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.

The Company evaluated subsequent events that would require an adjustment to the Company's condensed consolidated financial statements or require disclosure in the notes to the condensed consolidated financial statements. The Company has evaluated subsequent events through the date of issuance of the condensed consolidated financial statements.

(2) Recent Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2010-06, "Improving Disclosures about Fair Value Measurements" an amendment to Accounting Standards Codification ("ASC") Topic 820, "Fair Value Measurements and Disclosures." This amendment requires an entity to: (i) disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers, (ii) present separate information for Level 3 activity pertaining to gross purchases, sales, issuances, and settlements and (iii) enhance disclosures of assets and liabilities subject to fair value measurements. The provisions of ASU No. 2010-06 are effective for the Company for interim and annual reporting beginning after December 15, 2009, with one new disclosure effective after December 15, 2010. The Company adopted this ASU as of January 1, 2010. The adoption of this standard did not impact the Company's financial position or results of operations.

In June 2009, the FASB issued an amendment to a previously issued standard regarding consolidation of variable interest entities. This amendment was intended to improve financial reporting by enterprises involved with variable interest entities. Overall, the amendment revises the test for determining the primary beneficiary of a variable interest entity from a primarily quantitative analysis to a qualitative analysis. The provisions of the amendment are 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 adopted this standard as of January 1, 2010. The adoption of this standard did not impact the Company's financial position or results of operations.

(3) Share-Based Compensation

Prior to CVR's initial public offering in October 2007, CVR's subsidiaries were held and operated by CALLC. 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 standards issued by the FASB regarding the treatment of share-based compensation, as well as guidance regarding the accounting for share-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 these standards, CVR, CALLC, CALLC II and CALLC III apply a fair-value based measurement method in accounting for share-based compensation. In addition, 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 issued by the FASB regarding the accounting for equity instruments 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, 2010, 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 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 the 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.

Award Type	Benchmark Value (per Unit)	Original Awards Issued	Grant Date	*Compensation Expense Increase (Decrease) for the Three Months Ended June 30, 2010	2009	*Compensation Expense Increase (Decrease) for the Six Months Ended June 30, 2010	2009
Override Operating Units(a)	$ 11.31	919,630	June 2005	$ (78)	$ 904	$ 338	$ 1,487
Override Operating Units(b)	$ 34.72	72,492	December 2006	(2)	28	13	51
Override Value Units(c)	$ 11.31	1,839,265	June 2005	(1,184)	1,901	1,997	3,089
Override Value Units(d)	$ 34.72	144,966	December 2006	(13)	73	80	135
Override Units(e)	$ 10.00	138,281	October 2007	—	—	—	—
Override Units(f)	$ 10.00	642,219	February 2008	1	3	3	4
			Total	$ (1,276)	$ 2,909	$ 2,431	$ 4,766

* 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,		(b) Override Operating Units June 30,	
	2010	2009	2010	2009
Estimated forfeiture rate	None	None	None	None
CVR closing stock price	$7.52	$7.33	$7.52	$7.33
Estimated weighted-average fair value (per unit)	$13.02	$14.27	$2.06	$3.57
Marketability and minority interest discounts	20.0%	20.0%	20.0%	20.0%
Volatility	54.5%	59.3%	54.5%	59.3%

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. As of June 30, 2010 all recipients of the override operating units issued to date were fully vested.

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,	
	2010	2009	2010	2009
Estimated forfeiture rate	None	None	None	None
Derived service period	6 years	6 years	6 years	6 years
CVR closing stock price	$7.52	$7.33	$7.52	$7.33
Estimated weighted-average fair value (per unit)	$7.12	$7.69	$2.05	$3.57
Marketability and minority interest discounts	20.0%	20.0%	20.0%	20.0%
Volatility	54.5%	59.3%	54.5%	59.3%

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* — Using a binomial and a probability-weighted expected return method that utilized CALLC III’s cash flow 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. 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, 2010 these units were fully vested. Significant assumptions used in the valuation were as follows:

Estimated forfeiture rate	None
Grant date valuation (per unit)	$0.02
Marketability and minority interest discount	15.0%
Volatility	34.7%

(f) *Override Units* — Using a probability-weighted expected return method that utilized CALLC III's cash flow 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. 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, 2010	June 30, 2009
Estimated forfeiture rate	None	None
Derived Service Period	Based on forfeiture schedule	Based on forfeiture schedule
Estimated fair value (per unit)	$0.08	$0.03
Marketability and minority interest discount	20.0%	20.0%
Volatility	59.7%	47.0%

Based upon the estimated fair value at June 30, 2010, there was approximately $2,096,000 of unrecognized compensation expense related to non-voting override units. This expense is expected to be recognized over a remaining period of approximately one year as follows (in thousands):

	Override Value Units
Six months ending December 31, 2010	$ 1,077,000
Year ending December 31, 2011	1,019,000
	$ 2,096,000

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 CALLC and CALLC II 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, 2010, the issued Profits Interest (combined phantom points and override units) represented 15.0% 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. The expense associated with these awards 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 $12.46 and $6.96 per point, respectively, at June 30, 2010. Using the June 30, 2009, 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 valued at $14.27 and $7.69 per point, respectively. CVR has recorded approximately $8,366,000 and $6,723,000 in personnel accruals as of June 30, 2010 and December 31, 2009, respectively. Compensation expense for the three months ended June 30, 2010 related to the Phantom Unit Plans was reversed by $1,756,000. Compensation expense for the three months ended June 30, 2009 related to the Phantom Unit Plans was $2,603,000. Compensation expense for the six months ended June 30, 2010 and 2009 related to the Phantom Unit Plans was $1,643,000 and $4,498,000, respectively.

Based upon the estimated fair value at June 30, 2010, there was approximately $658,000 of unrecognized compensation expense related to the Phantom Unit Plans. This is expected to be recognized over a remaining period of approximately one year.

Long-Term Incentive Plan

CVR has a Long-Term Incentive Plan ("LTIP") that permits the grant of options, stock appreciation rights, 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, 2010, there have been a total of 32,350 stock options granted, of which 18,536 have vested. During the three months ended June 30, 2010, 1,450 stock options vested and 3,149 stock options were forfeited. There were no grants of stock options for the six months ended June 30, 2010. The fair value of stock options is estimated on the date of grant using the Black-Scholes option pricing model. As of June 30, 2010, there was approximately $26,000 of total unrecognized compensation cost related to stock options to be recognized over a weighted-average period of approximately one year.

Non-Vested Stock

A summary of non-vested stock grant activity and changes during the six months ended June 30, 2010 is presented below:

Non-Vested Stock	Shares	Weighted-Average Grant-Date Fair Value
Outstanding at January 1, 2010 (non-vested)	177,060	$ 6.59
Vested	(20,013)	8.90
Granted	10,013	7.99
Forfeited	(1,799)	4.14
Outstanding at June 30, 2010 (non-vested)	165,261	$ 6.43

Through the LTIP, shares of non-vested stock have been granted to employees and directors of the Company. Non-vested shares, when granted, are valued at the closing market price of CVR's common stock on the date of issuance and amortized to compensation expense on a straight-line basis over the vesting period of the stock. These shares generally vest over a three-year period. As of June 30, 2010, there was approximately $597,000 of total unrecognized compensation cost related to non-vested shares to be recognized over a weighted-average period of approximately two years.

Compensation expense recorded for the three months ended June 30, 2010 and 2009 related to the non-vested stock and stock options was $188,000 and $113,000, respectively. Compensation expense recorded for the six months ended June 30, 2010 and 2009 related to the non-vested stock and stock options was $361,000 and $215,000, 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 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, 2010	December 31, 2009
Finished goods	$ 100,405	$ 123,548
Raw materials and catalysts	104,480	107,840
In-process inventories	22,515	19,401
Parts and supplies	24,222	24,049
	$ 251,622	$ 274,838

(5) Property, Plant, and Equipment

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

	June 30, 2010	December 31, 2009
Land and improvements	$ 18,494	$ 18,016
Buildings	24,876	23,316
Machinery and equipment	1,351,779	1,305,362
Automotive equipment	8,782	8,796
Furniture and fixtures	8,509	8,095
Leasehold improvements	1,220	1,301
Construction in progress	42,435	77,818
	1,456,095	1,442,704
Accumulated depreciation	346,822	304,794
	$ 1,109,273	$ 1,137,910

Capitalized interest recognized as a reduction in interest expense for the three months ended June 30, 2010 and 2009, totaled approximately $766,000 and $389,000, respectively. Capitalized interest recognized as a reduction in interest expense for the six months ended June 30, 2010 and 2009, totaled approximately $1,647,000 and $802,000, respectively. Land and buildings that are under a capital lease obligation approximated $4,827,000 as of June 30, 2010. 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 $738,000 and $719,000 for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009 cost of product sold excludes depreciation and amortization of $1,466,000 and $1,430,000, 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 exclude depreciation and amortization of $20,301,000 and $19,922,000 for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009 direct operating expenses exclude depreciation and amortization of $40,319,000 and $39,664,000, 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 exclude depreciation and amortization of $514,000 and $466,000 for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, selling, general and administrative expenses exclude depreciation and amortization of $1,028,000 and $922,000, respectively.

(7) Note Payable and Capital Lease Obligations

The Company entered into an insurance premium finance agreement in July 2009 to finance a portion of the purchase of its 2009/2010 property, liability, cargo and terrorism insurance policies. The original balance of the note provided by the Company under such agreement was $10,000,000. As of June 30, 2010, the Company repaid the entire note obligation. As of December 31, 2009, the Company owed $7,500,000 related to this note.

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 2010, the Company renewed the lease for a one-year period commencing June 5, 2010. In connection with this capital lease, the Company makes quarterly lease payments that 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 originally recorded a capital asset and capital lease obligation of $4,827,000. The capital lease obligation was $4,427,000 and $4,274,000 as of June 30, 2010 and December 31, 2009, respectively.

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

For the three months ended June 30, 2010 and 2009, the Company recorded pre-tax expenses, net of anticipated insurance recoveries of $0 and $(101,000), respectively, associated with the June/July 2007 flood and associated crude oil discharge. For the six months ended June 30, 2010 and 2009, the Company recorded pre-tax expenses, net of anticipated insurance recoveries of $0 and $80,000, 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 Condensed Consolidated Statements of Operations. 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 under these policies only.

As of June 30, 2010, the remaining receivable from environmental insurance carriers was not anticipated to be collected in the next twelve months, and therefore has been classified as a non-current asset. 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.

(9) Income Taxes

As of June 30, 2010, 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 generally subject to examination as of June 30, 2010 are 2006 to 2009. The United States Internal Revenue Service completed an examination of CVR and certain of its subsidiaries' U.S. federal income tax returns for the tax year ended December 31, 2007 and also of a subsidiary for the tax year ended October 16, 2007. The examinations were concluded with no changes to the 2007 returns as filed.

The Company's effective tax rate for the three and six months ended June 30, 2010 was (58.5)% and 42.0%, respectively, as compared to the Company's combined federal and state expected statutory tax rate of 39.7%. The Company's effective tax rate for the three and six months ended June 30, 2009 was 37.4% and 33.8%, respectively. The effective tax rate for the three and six months ended June 30, 2010 varies from the statutory rate primarily due to the receipt and recognition of interest income on federal income tax refunds received during the second quarter of 2010. The correlation of the recognition of the tax affected interest income with the pre-tax income and loss levels increased the effective tax rate of the tax benefit recorded for the periods in 2010. The effective tax rate for the three and six months ended June 30, 2009 was lower than the expected statutory tax rate due primarily to federal income tax credits available to small business refiners related to the production of ultra low sulfur diesel fuel. There have been no federal or state income tax credits included in the projected annualized effective tax rate for 2010.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(10) Earnings Per Share

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

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
	(in thousands, except share data)			
Net income (loss)	$ 1,152	$ 42,699	$ (11,211)	$ 73,330
Weighted-average common shares outstanding	86,336,125	86,244,152	86,332,700	86,243,949
Effect of dilutive securities:				
Non-vested common stock	170,465	89,197	—	83,962
Weighted-average common shares outstanding assuming dilution	86,506,590	86,333,349	86,332,700	86,327,911
Basic earnings (loss) per share	$ 0.01	$ 0.49	$ (0.13)	$ 0.85
Diluted earnings (loss) per share	$ 0.01	$ 0.49	$ (0.13)	$ 0.85

Outstanding stock options totaling 29,201 common shares were excluded from the diluted earnings (loss) per share calculation for the three and six months ended June 30, 2010, respectively, as they were antidilutive. Outstanding stock options totaling 32,350 common shares were excluded from the diluted earnings (loss) per share calculation for the three and six months ended June 30, 2009, respectively, as they were antidilutive. For the six months ended June 30, 2010, 173,715 shares of non-vested common stock were excluded from the diluted earnings (loss) per share calculation, 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 Leases	Unconditional Purchase Obligations(1)
Six months ending December 31, 2010	$ 2,709	$ 16,498
Year ending December 31, 2011	5,617	30,337
Year ending December 31, 2012	5,639	27,552
Year ending December 31, 2013	3,036	27,706
Year ending December 31, 2014	2,188	27,706
Thereafter	1,909	153,271
	$ 21,098	$ 283,070

(1) This amount excludes approximately $510,000,000 potentially payable under petroleum transportation service agreements between Coffeyville Resources Refining & Marketing, LLC ("CRRM") and TransCanada Keystone Pipeline, LP ("TransCanada"), pursuant to which CRRM would receive transportation of at least 25,000 barrels per day of crude oil with a delivery point at Cushing, Oklahoma for a term of ten years on a new pipeline system being constructed by TransCanada. This $510,000,000 would be payable ratably over the ten 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 filed a Statement of Claim in the Court of the Queen's Bench of Alberta, Judicial District of Calgary, on September 15, 2009, 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, 2010 and 2009, lease expense totaled $1,429,000 and $1,292,000, respectively. For the six months ended June 30, 2010 and 2009, lease expense totaled $2,621,000 and $2,481,000, 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

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 condensed consolidated financial statements. There can be no assurance that management's beliefs or opinions with respect to liability for potential litigation matters are accurate.

Samson Resources Company, Samson Lone Star, LLC and Samson Contour Energy E&P, LLC (together, "Samson") filed fifteen lawsuits in federal and state courts in Oklahoma and two lawsuits in state courts in New Mexico against CRRM and other defendants between March 2009 and July 2009. In addition, in May 2010, separate groups of plaintiffs filed two lawsuits against CRRM and other defendants in federal court in Oklahoma and Kansas. All of the lawsuits allege that Samson or the other respective plaintiffs sold crude oil to a group of companies, which generally are known as SemCrude or SemGroup (collectively, "Sem"), which later declared bankruptcy and that Sem has not paid such plaintiffs for all of the crude oil purchased from Sem. The Samson lawsuits further allege that Sem sold some of the crude oil purchased from the plaintiffs to J. Aron & Company ("J. Aron") and that J. Aron 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 the plaintiffs' alleged claims are unknown since the price and amount of crude oil sold by the plaintiffs 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 and intends to vigorously defend against these claims.

The Company received a letter dated January 27, 2010, from the Litigation Trust formed pursuant to the Sem bankruptcy plan of reorganization claiming that $41,625,000 received by the Company from various Sem entities within the 90 day period prior to the Sem bankruptcy on July 22, 2008, may constitute recoverable preferences under the U.S. Bankruptcy Code. This claim has been settled in a manner favorable to the Company and the settlement will not have a material adverse effect on the condensed consolidated financial statements.

See note (1) to the table at the beginning of this Note 11 (“Commitments and Contingent Liabilities”) for a discussion of the TransCanada litigation.

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 (“Angleton Case”). In October, 2009, a companion case to the Angleton Case was filed in the United States District Court for the District of Kansas in Wichita, seeking a total of $3,200,000 for three additional plaintiffs as a result of the July 1, 2007 crude oil discharge. The 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. By July 2008, the Company substantially completed remediating the damage caused by the crude oil discharge. 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.

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 nor can they 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 environmental and property 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 its 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, its 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 additional 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 Company has received $25,000,000 of insurance proceeds under its primary environmental liability insurance policy which constitutes full payment to the Company of the primary pollution liability policy limit.

The lawsuit with the insurance carriers under the environmental 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. 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 these locations.

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, 2010 and December 31, 2009, environmental accruals of $4,626,000 and $5,007,000, respectively, were reflected in the Condensed Consolidated Balance Sheets for probable and estimated costs for remediation of environmental contamination under the RCRA Administrative Orders and the VCPRP, for which $1,783,000 and $2,179,000, respectively, are included as other current liabilities. The Company's accruals were determined based on an estimate of payment costs through 2031 and were discounted at the appropriate risk free rates at June 30, 2010 and December 31, 2009, respectively. The accruals include estimated closure and post-closure costs of $984,000 and $883,000 for two landfills at June 30, 2010 and December 31, 2009, respectively. The estimated future payments for these obligations are as follows (in thousands):

	Amount
Six months ending December 31, 2010	$ 1,598
Year ending December 31, 2011	370
Year ending December 31, 2012	435
Year ending December 31, 2013	325
Year ending December 31, 2014	431
Thereafter	2,023
Undiscounted total	5,182
Less amounts representing interest at 2.49%	556
Accrued environmental liabilities at June 30, 2010	$ 4,626

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 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. In the second quarter of 2010, CRRM completed the installation of controls required to achieve compliance with the ULSG standards. As such, beginning on January 1, 2011, CRRM will have fulfilled its remaining obligations under the “hardship waiver” (other than the final compliance report) and will be subject to all of the requirements of the ULSD and ULSG programs, without exception. CRRM will not report further on these programs unless there is a material change. Compliance with the Tier II gasoline and on-road diesel standards required the Company to spend approximately $20,589,000 during 2009, $13,787,000 during 2008, $16,800,000 during 2007 and $79,033,000 during 2006. Based on information currently available, CRRM anticipates spending approximately $13,985,000 in 2010 to comply with ULSG requirements. The entire amounts are expected to be capitalized. For the three months ended June 30, 2010 and 2009, CVR spent $2,831,000 and $3,633,000, respectively. For the six months ended June 30, 2010 and 2009, CVR spent $9,582,000 and $7,082,000, respectively.

In 2007, the EPA promulgated the Mobile Source Air Toxic II (“MSAT II”) rule, that requires the reduction of benzene in gasoline by 2011. CRRM is considered a small refiner under the MSAT II 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 expenditures to comply with the rule will not begin before 2013.

In February 2010, the EPA finalized changes to the Renewable Fuel Standards (“RFS2”) which require the total volume of renewable transportation fuels sold or introduced in the United States to reach 12.95 billion gallons in 2010 and rise to 36 billion gallons by 2022. Due to mandates in the RFS2 requiring increasing volumes of renewable fuels to replace petroleum products in the U.S. motor fuel market, there may be a decrease in demand for petroleum products. In addition, CRRM may be impacted by increased capital expenses and production costs to accommodate mandated renewable fuel volumes. CRRM’s small refiner status under the original Renewable Fuel Standards will continue under the RFS2 and therefore, CRRM is exempted from the requirements of the RFS2 through December 31, 2010. Beginning on January 1, 2011, CRRM will be required to begin blending renewable fuel into its gasoline and diesel fuel or purchase renewable energy credits (“RINs”) in lieu of blending.

In March 2004, CRRM and CRT entered into a Consent Decree (the “Consent Decree”) with the EPA and the Kansas Department of Health and Environment (the “KDHE”) to resolve air compliance concerns raised by the EPA and KDHE related to Farmland Industries, Inc.’s (“Farmland”) prior ownership and operation of the refinery. As a result of our agreement to install certain controls and implement certain operational changes, the EPA and KDHE agreed not to impose civil penalties, and provided a release from liability for Farmland’s alleged noncompliance with the issues addressed by the Consent Decree. Under the Consent Decree, CRRM agreed to install controls to reduce emissions of sulfur dioxide, nitrogen oxides and particulate matter from its FCCU by January 1, 2011. In addition, pursuant to the Consent Decree, CRRM and CRT assumed cleanup obligations at the Coffeyville refinery and the Phillipsburg terminal facilities. The costs of complying with the Consent Decree are expected to be approximately $54 million, of which approximately $44 million is expected to be capital expenditures which do not include the cleanup obligations for historic contamination at the site that are being addressed pursuant to administrative orders issued under the RCRA. To date, CRRM and CRT have materially complied with the Consent Decree. On June 30, 2009, CRRM submitted a force majeure notice to the EPA and KDHE in which CRRM indicated that it may be unable to meet the Consent Decree’s January 1, 2011 deadline related to the installation of controls on the FCCU because of delays caused by the June/July 2007 flood. In February 2010, CRRM and the EPA agreed to a 15-month extension of the January 1, 2011 deadline for the installation of controls which was approved by the Court as a material modification to the existing Consent Decree. Pursuant to this agreement, CRRM will offset any incremental emissions resulting from the delay by providing additional controls to existing emission sources over a set timeframe.

Over the course of the last decade, the EPA has embarked on a national Petroleum Refining Initiative alleging industry-wide noncompliance with four “marquee” issues under the Clean Air Act: New Source Review, Flaring, Leak Detection and Repair, and Benzene Waste Operations NESHAP. The Petroleum

Refining Initiative has resulted in most refiners entering into consent decrees imposing civil penalties and requiring substantial expenditures for air pollution controls and enhanced operating procedures. The EPA has indicated that it will seek to have all refiners enter into "global settlements" pertaining to all "marquee" issues. The Company's current Consent Decree covers some, but not all, of the "marquee" issues. We currently are in negotiations with EPA and KDHE under the Petroleum Refining Initiative. To date, the EPA has not made any specific claims or findings against us and we have not determined whether we will ultimately enter into a "global settlement" agreement with the EPA and KDHE. By entering into a "global settlement", we may be able to extend the deadline for the installation of controls on the FCCU required under the 2004 Consent Decree. If we agree to enter into a global settlement we would be required to pay a civil penalty, but our incremental capital expenses would be limited primarily to the retrofit and replacement of heaters and boilers over a seven-year timeframe. EPA, KDHE and CRRM have reached an agreement in principle on most of the "marquee" issues and continue negotiations concerning the remaining issues.

On February 24, 2010, the Company received a letter from the United States Department of Justice on behalf of the EPA seeking a $900,000 civil penalty related to alleged late and incomplete reporting of air releases in violation of the Comprehensive Environmental Response, Compensation, and Liability Act and the Emergency Planning and Community Right to Know Act. The Company has reviewed and intends to contest the EPA's allegations.

Environmental expenditures are capitalized when such expenditures are expected to result in future economic benefits. For the three months ended June 30, 2010 and 2009, capital environmental expenditures were $3,303,000 and $5,404,000, respectively. For the six months ended June 30, 2010 and 2009, capital environmental expenditures were $10,966,000 and $9,367,000, respectively. These expenditures were incurred to improve environmental compliance and efficiency of operations.

CRRM, CRNF, CRCT and CRT each believe it is 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 business, financial condition, or results of operations.

(12) Long-Term Debt

Long-term debt was as follows (in thousands):

	June 30, 2010	December 31, 2009
Tranche D term loans	$ —	$ 479,503
9.0% Senior Secured Notes, due 2015, net of unamortized discount of $1,295 as of June 30, 2010	273,705	—
10.875% Senior Secured Notes, due 2017, net of unamortized discount of $2,615 as of June 30, 2010	222,385	—
Long-term debt	496,090	479,503
Current portion of long-term debt	—	4,777
Long-term debt, net of current portion	$ 496,090	$ 474,726

Senior Secured Notes

On April 6, 2010, CRLLC and its newly formed wholly-owned subsidiary, Coffeyville Finance Inc. (together the "Issuers"), completed a private offering of $275,000,000 aggregate principal amount of 9.0% First Lien Senior Secured Notes due 2015 (the "First Lien Notes") and $225,000,000 aggregate principal amount of 10.875% Second Lien Senior Secured Notes due 2017 (the "Second Lien Notes" and together with the First Lien Notes, the "Notes"). At June 30, 2010, the estimated fair value of the First and Second Lien Notes was $275,250,000 and $219,375,000, respectively. These estimates of fair value were determined by quotations obtained from a broker-dealer who makes a market in these and similar securities. The Notes are fully and unconditionally guaranteed by each of CRLLC's subsidiaries that also guarantee the first priority credit facility.

CRLLC received total net proceeds from the offering of approximately $485,693,000, net of underwriter fees of $10,000,000 and original issue discount of $4,020,000 and certain third party fees of $287,000. In addition, CRLLC incurred additional third party fees and expenses, net of write-offs and adjustments, totaling $3,600,000 associated with the offering. CRLLC applied the net proceeds to prepay all of the outstanding balance of its tranche D term loan under its first priority credit facility in an amount equal to $453,304,000 and to pay related fees and expenses. In accordance with the terms of its first priority credit facility, CRLLC paid a 2.0% premium totaling $9,066,000 to the lenders of the term debt upon the prepayment of the outstanding balance. This amount is recorded as a loss on extinguishment of debt during the second quarter of 2010. Additionally, due to the prepayment and termination of the term debt, a write-off of previously deferred financing charges of $5,380,000 is reflected in the Condensed Consolidated Statement of Operations as a loss on extinguishment of debt for the second quarter of 2010. The discount and related debt issuance costs of the Notes are being amortized over the term of the applicable Notes.

The First Lien Notes mature on April 1, 2015, unless earlier redeemed or repurchased by the Issuers. The Second Lien Notes mature on April 1, 2017, unless earlier redeemed or repurchased by the Issuers. Interest is payable on the Notes semi-annually on April 1 and October 1 of each year commencing on October 1, 2010.

First Priority Credit Facility

Until April 6, 2010, CRLLC maintained tranche D term debt totaling $453,304,000. As documented above, this amount was paid in full with the proceeds of the issuance of the Notes. As of June 30, 2010 the first priority credit facility consisted of a $150,000,000 revolving credit facility. The revolving credit facility provides for direct cash borrowings for general corporate purposes and on a short-term basis. Letters of credit issued under the revolving credit facility are subject to a $100,000,000 sub-limit. Outstanding letters of credit reduce the amount available under the Company's revolving credit facility. As of June 30, 2010, CRLLC had $30,761,000 of outstanding letters of credit consisting of: $193,000 in letters of credit in support of certain environmental obligations and $30,569,000 in letters of credit to secure transportation services for crude oil. The revolving loan commitment expires on December 28, 2012. As of June 30, 2010, the Company had no borrowings outstanding under the revolving credit facility and had aggregate availability of $119,239,000 under the revolving credit facility.

The first priority credit facility contains customary covenants and restrictions. As of June 30, 2010, the Company was in compliance with these covenants and restrictions under the first priority credit facility.

Included in other current liabilities on the Condensed Consolidated Balance Sheets is accrued interest payable $12,002,000 and $10,964,000 at June 30, 2010 and December 31, 2009, respectively. Of these amounts $11,462,000 and $10,588,000 are related to CRLLC's Notes and credit facility borrowing arrangement at June 30, 2010 and December 31, 2009, respectively.

(13) Fair Value Measurements

In September 2006, the FASB issued ASC 820 — *Fair Value Measurements and Disclosures* ("ASC 820"). ASC 820 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. ASC 820 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.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

ASC 820 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). ASC 820 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)

The following table sets forth the assets and liabilities measured at fair value on a recurring basis, by input level, as of June 30, 2010 and December 31, 2009 (in thousands):

Location and Description	June 30, 2010			
	Level 1	Level 2	Level 3	Total
Cash equivalents (money market account)	$ 25	$ —	$ —	$ 25
Other current assets (Other derivative agreements)	—	57	—	57
Total Assets	$ 25	$ 57	$ —	$ 82
	December 31, 2009			
	Level 1	Level 2	Level 3	Total
Cash equivalents (money market account)	$ 723	$ —	$ —	$ 723
Total Assets	$ 723	$ —	$ —	$ 723
Derivatives:				
Other current liabilities (Interest Rate Swap)	$ —	$ (2,830)	$ —	$ (2,830)
Other current liabilities (Other derivative agreements)	—	(1,847)	—	(1,847)
Total Derivatives	$ —	$ (4,677)	$ —	$ (4,677)
Total Liabilities	$ —	$ (4,677)	$ —	$ (4,677)

As of June 30, 2010, 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. Additionally, the fair value of the Company's Notes are disclosed in Note 12 ("Long-Term Debt"). Until June 30, 2010, the Company was a counterparty to the Interest Rate Swap (defined in Note 14 ("Derivative Financial Instruments")). The Interest Rate Swap expired on June 30, 2010. Until expiration, the Company valued the financial statement position of the Interest Rate Swap using Level 2 inputs. The Company obtained broker quotations from the respective counterparties to the Interest Rate Swap. These quotations were derived from projected yield curves that considered inputs that included but were not limited to market risk, interest risk and credit risk. See Note 14 ("Derivative Financial Instruments") for further discussion of the Interest Rate Swap. Given the degree of varying assumptions used to value the Interest Rate Swap, it was deemed as having Level 2 inputs. The Company's commodity derivative contracts giving rise to a liability under Level 2 are valued using broker quoted market prices of similar commodity contracts. The Company had no transfers of assets or liabilities between any of the above levels during the six months ended June 30, 2010. The carrying value of the

Company's long-term tranche D term debt held until April 6, 2010 approximated fair value as a result of floating interest rates assigned to this financial instrument.

(14) Derivative Financial Instruments

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Realized gain (loss) on cash flow swap agreements	$ —	$ (2,701)	$ —	$ (18,416)
Unrealized gain (loss) on cash flow swap agreements	—	(19,876)	—	(39,990)
Realized gain (loss) on other derivative agreements	6,872	(5,814)	6,956	(6,817)
Unrealized gain (loss) on other derivative agreements	468	(225)	1,904	(62)
Realized gain (loss) on interest rate swap agreements	(1,086)	(1,354)	(2,861)	(3,064)
Unrealized gain (loss) on interest rate swap agreements	1,085	737	2,830	2,255
Total gain (loss) on derivatives, net	$ 7,339	$ (29,233)	$ 8,829	$ (66,094)

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 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 was for the purpose of managing interest rate risk.

CVR has adopted accounting standards which impose extensive record-keeping requirements in order to designate a derivative financial instrument as a hedge. CVR holds derivative instruments, such as exchange-traded crude oil futures and certain over-the-counter forward swap agreements which it believes provide an economic hedge on future transactions, but such instruments are not designated as hedges for GAAP purposes. Gains or losses related to the change in fair value and periodic settlements of these derivative instruments are classified as gain (loss) on derivatives, net in the Condensed Consolidated Statements of Operations.

Cash Flow Swap

Until October 8, 2009, CRLLC had been a party to commodity derivative contracts (referred to as the "Cash Flow Swap") that were originally executed on June 16, 2005. The swap agreements were executed at the prevailing market rate at the time of execution and were to provide an economic hedge on future transactions. The Cash Flow Swap resulted in unrealized gains (losses), using a valuation method that utilized quoted market prices. All of the activity related to the Cash Flow Swap is reported in the Petroleum Segment. On October 8, 2009, CRLLC and J. Aron mutually agreed to terminate the Cash Flow Swap. The Cash Flow Swap was expected to terminate in 2010; however, the third amendment to the Company's first priority credit facility permitted early termination.

Interest Rate Swap

Until June 30, 2010, 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 from March 31, 2009 until March 31, 2010 and $110,000,000 million from March 31, 2010 until June 30, 2010. The Interest Rate Swap expired on June 30, 2010. Half of the Interest

Rate Swap agreements were held with a related party (as described in Note 15, "Related Party Transactions"), and the other half were held with a financial institution that was also a lender under CRLLC's first priority credit facility until April 6, 2010.

Under the Interest Rate Swap, CRLLC paid the fixed rate of 4.195% and received a floating rate based on three month LIBOR rates, with payments calculated on the notional amount. The notional amount did not represent the actual amount exchanged by the parties but instead represented the amount on which the contracts are based. The Interest Rate Swap was settled quarterly and marked to market at each reporting date with all unrealized gains and losses recognized in income. Transactions related to the Interest Rate Swap agreements were not allocated to the Petroleum or Nitrogen Fertilizer segments.

(15) 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 the Cash Flow Swap with 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 14, "Derivative Financial Instruments", the Cash Flow Swap was terminated by the parties effective October 8, 2009. For the three months ended June 30, 2009, the Company recognized net realized and unrealized losses totaling $22,577,000 related to these swap agreements which are reflected in gain (loss) on derivatives, net in the Condensed Consolidated Statements of Operations. For the six months ended June 30, 2009, the Company recognized net realized and unrealized losses totaling $58,406,000 related to these swap agreements, which are reflected in gain (loss) on derivatives, net in the Condensed Consolidated Statements of Operations.

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 and the remaining deferral obligation of $62,375,000 including accrued interest of $509,000 was paid in the first quarter of 2009, resulting in the Company being unconditionally and irrevocably released from any and all of its obligations under the deferred agreements. In addition, J. Aron released the Goldman Sachs Funds and the Kelso Funds from any and all of their obligations to guarantee the deferred payment obligations. Interest expense related to the deferral agreement totaled $0 and $307,000 for the three and six months ended June 30, 2009, respectively.

Interest Rate Swap

On June 30, 2005, the Company also entered into three Interest Rate Swap agreements with J. Aron. Net losses for the three months ended June 30, 2010 related to these agreements were nominal. Net losses totaling $311,000 were recognized related to these swap agreements for the three months ended June 30, 2009 and are reflected in gain (loss) on derivatives, net in the Condensed Consolidated Statements of Operations. Net losses totaling $16,000 and $408,000 were recognized related to these swap agreements for the six months ended June 30, 2010 and 2009, respectively, and are reflected in gain (loss) on derivatives, net in the Condensed Consolidated Statements of Operations. In addition, the Condensed Consolidated Balance Sheet at June 30, 2010 and December 31, 2009 includes $0 and $1,415,000, respectively, in other current liabilities. See Note 14, ("Derivative Financial Instruments") for additional information.

Cash and Cash Equivalents

The Company holds a portion of its cash balance in a highly liquid money market account with average maturities of less than 90 days within the Goldman Sachs Funds family. As of June 30, 2010 and December 31, 2009, the balance in the account was approximately $25,000 and $723,000, respectively. For the three months ended June 30, 2010 and 2009, the account earned interest income of $2,000 and $29,000, respectively. For the six months ended June 30, 2010 and 2009, the account earned $2,000 and $44,000 of interest income, respectively.

Financing and Other

In March 2010, CRLLC amended its outstanding first priority credit facility. In connection with the amendment, CRLLC paid a subsidiary of GS fees and expenses of $904,500 for their services as lead bookrunner. In addition, on April 6, 2010, a subsidiary of GS received a fee as a participating underwriter of $2,000,000 upon completion of the issuance of the Notes (as described in Note 12 "Long-Term Debt").

For the three months ended June 30, 2010 and 2009, the Company purchased approximately $38,000 and $38,000, respectively, of Fluid Catalytic Cracking Unit additives from Intercat, Inc. For the six months ended June 30, 2010 and 2009, the Company purchased approximately $276,000 and $115,000, respectively, of Fluid Catalytic Cracking Unit additives from Intercat, Inc. Mr. Regis Lippert, a director, and the President, CEO and majority shareholder of Intercat, Inc. was also a director of the Company until May 19, 2010.

For the three and six months ended June 30, 2010, the Company recognized approximately $372,000 and $393,000, respectively in expenses for the benefit of GS and Kelso in accordance with CVR's Registration Rights Agreement. These amounts included registration and filing fees, printing fees, external accounting fees and external legal fees.

(16) Business Segments

The Company measures segment profit as operating income for Petroleum and Nitrogen Fertilizer, CVR's two reporting segments, based on the definitions provided in ASC 280 — *Segment Reporting*. All operations of the segments are located within the United States.

Petroleum

Principal products of the Petroleum Segment are refined fuels, propane and petroleum refining by-products including pet coke. The Petroleum Segment sells the pet coke to the Partnership for use in the manufacture of nitrogen fertilizer at the adjacent nitrogen fertilizer plant. For the Petroleum Segment, a per-ton transfer price is used to record intercompany sales on the part of the Petroleum Segment and a corresponding intercompany cost of product sold (exclusive of depreciation and amortization) is recorded 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 Nitrogen 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 $1,755,000 and $2,002,000 for the three months ended June 30, 2010 and 2009, respectively. Intercompany sales included in Petroleum net sales were $2,167,000 and $5,020,000 for the six months ended June 30, 2010 and 2009, respectively.

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 months ended June 30, 2010 and 2009 of $(565,000) and $(443,000), respectively. For the six months ended June 30, 2010 and 2009, the Petroleum Segment recorded intercompany costs of product sold (exclusive of depreciation and amortization) for hydrogen sales of $(1,133,000) and $215,000, 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 $574,000 and $2,549,000 for the three months ended June 30, 2010 and 2009, respectively. Intercompany cost of product sold (exclusive of depreciation and amortization) for the pet coke transfer described above was $1,012,000 and $6,085,000 for the six months ended June 30, 2010 and 2009, 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 cost of product sold (exclusive of depreciation and amortization) from intercompany hydrogen purchases of $565,000 and $1,133,000 for the three and six months ended June 30, 2010, respectively. For the three and six months ended June 30, 2009, the Nitrogen Fertilizer Segment recorded net sales generated from intercompany sales of hydrogen to the Petroleum Segment of $1,000 and $659,000, respectively, and recorded costs 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 from the Petroleum Segment.

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Other Segment

The Other Segment reflects intercompany eliminations, 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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in thousands)			
Net sales				
Petroleum	$ 951,330	$ 739,952	$ 1,808,018	$ 1,285,234
Nitrogen Fertilizer	56,346	55,355	94,631	123,144
Intersegment eliminations	(1,778)	(2,003)	(2,239)	(5,679)
Total	$ 1,005,898	$ 793,304	$ 1,900,410	$ 1,402,699
Cost of product sold (exclusive of depreciation and amortization)				
Petroleum	$ 882,150	$ 581,657	$ 1,681,101	$ 999,255
Nitrogen Fertilizer	11,880	8,245	16,857	16,927
Intersegment eliminations	(2,378)	(2,267)	(3,416)	(6,942)
Total	$ 891,652	$ 587,635	$ 1,694,542	$ 1,009,240
Direct operating expenses (exclusive of depreciation and amortization)				
Petroleum	$ 41,145	$ 32,973	$ 79,534	$ 67,595
Nitrogen Fertilizer	21,334	21,474	43,507	43,086
Other	—	—	—	—
Total	$ 62,479	$ 54,447	$ 123,041	$ 110,681
Net costs associated with flood				
Petroleum	$ —	$ (101)	$ —	$ 80
Nitrogen Fertilizer	—	—	—	—
Other	—	—	—	—
Total	$ —	$ (101)	$ —	$ 80
Depreciation and amortization				
Petroleum	$ 16,418	$ 15,962	$ 32,552	$ 31,840
Nitrogen Fertilizer	4,671	4,720	9,336	9,336
Other	464	425	925	840
Total	$ 21,553	$ 21,107	$ 42,813	$ 42,016
Operating income (loss)				
Petroleum	$ 4,645	$ 96,232	$ (2,449)	$ 160,891
Nitrogen Fertilizer	16,502	16,527	19,470	45,809
Other	(1,726)	(4,315)	(9,194)	(7,296)
Total	$ 19,421	$ 108,444	$ 7,827	$ 199,404
Capital expenditures				
Petroleum	$ 4,141	$ 6,637	$ 13,250	$ 14,029
Nitrogen Fertilizer	753	2,136	1,969	9,567
Other	516	(116)	1,607	979
Total	$ 5,410	$ 8,657	$ 16,826	$ 24,575

	As of June 30, 2010	As of December 31, 2009
	(in thousands)	
Total assets		
Petroleum	$ 1,092,232	$ 1,082,707
Nitrogen Fertilizer	731,005	702,929
Other	(202,546)	(171,142)
Total	$ 1,620,691	$ 1,614,494
Goodwill		
Petroleum	$ —	$ —
Nitrogen Fertilizer	40,969	40,969
Other	—	—
Total	$ 40,969	$ 40,969

(17) Subsequent Events

Crude Oil Supply Agreement

On July 19, 2010, CRRM entered into an amendment to the Crude Oil Supply Agreement, dated December 2, 2008, as amended, with Vitol, Inc. ("Vitol"). The amendment extends the initial term of the Crude Oil Supply Agreement from three to four years ending December 31, 2012, whereby Vitol agrees to continue to provide crude oil supply and logistic intermediation on behalf of CRRM.

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, 2010, as well as our Annual Report on Form 10-K for the year ended December 31, 2009. Results of operations for the three and six months ended June 30, 2010 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, 2009 and in our From 10-Q for the quarter ended March 31, 2010. Such factors include, among others:

- volatile margins in the refining industry;
- 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;
- interruption of the pipelines supplying feedstock and in the distribution of our products;
- competition in the petroleum and nitrogen fertilizer businesses;
- capital expenditures required by environmental laws and regulations;
- changes in our credit profile;
- the potential decline in the price of natural gas, which historically has correlated with the market price of nitrogen fertilizer products;
- the cyclical nature of the nitrogen fertilizer business;
- adverse weather conditions, including potential floods and other natural disasters;
- the supply and price levels of essential raw materials;

- the volatile nature of ammonia, potential liability for accidents involving ammonia that cause severe damage to property and/or injury to the environment and human health and potential increased costs relating to the transport of ammonia;
- the dependence of the nitrogen fertilizer operations on a few third-party suppliers, including providers of transportation services and equipment;
- the potential loss of the nitrogen fertilizer business' transportation cost advantage over its competitors;
- existing and proposed environmental laws and regulations, including those relating to climate change, alternative energy or fuel sources, and the end-use and application of fertilizers;
- refinery operating hazards and interruptions, including unscheduled maintenance or downtime, and the availability of adequate insurance coverage;
- our significant indebtedness; and
- instability and volatility in the capital and credit markets.

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") is an 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 and associated incentive distribution rights) in CVR Partners, LP (the "Partnership"), a limited partnership which produces nitrogen fertilizers, ammonia and 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 bpd complex full coking medium-sour crude oil refinery in Coffeyville, Kansas. In addition, supporting businesses include (1) a crude oil gathering system with a gathering capacity of approximately 35,000 bpd serving Kansas, Oklahoma, western Missouri and southwestern Nebraska, (2) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and at throughput terminals on Magellan's refined products distribution systems, (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) storage and terminal facilities for refined fuels and asphalt in Phillipsburg, Kansas.

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. In addition to rack sales (sales which are made at terminals into third party tanker trucks), we make bulk sales (sales through third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise Products Operating, L.P. and NuStar Energy, L.P.

Crude oil is supplied to our refinery through our gathering system and by a Plains pipeline from Cushing, Oklahoma. We maintain capacity on the Spearhead Pipeline from Canada and have access to foreign and deepwater domestic crude oil via the Seaway Pipeline system from the U.S. Gulf Coast to Cushing. 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 from time-to-time 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 WTI. Our crude consumed cost discount to WTI for the second quarter of 2010 was $(1.77) per barrel compared to $(6.38) per barrel in the second quarter of 2009.

Nitrogen fertilizer business. The nitrogen fertilizer business consists of our interest in the Partnership, which is controlled by our affiliates. The nitrogen fertilizer business consists of a nitrogen fertilizer manufacturing facility, including (1) a 1,225 ton-per-day ammonia unit, (2) a 2,025 ton-per-day UAN unit and (3) a dual train gasifier complex each with a capacity of 84 million standard cubic feet per day, capable of processing approximately 1,400 tons per day of pet coke to produce hydrogen.

The nitrogen fertilizer plant in Coffeyville, Kansas includes two pet coke gasifiers that produce high purity hydrogen which in turn is converted to ammonia at a related ammonia synthesis plant. Ammonia is further upgraded into UAN solution in a related UAN unit. In 2009, the nitrogen fertilizer business produced 435,184 tons of ammonia, of which approximately 64% was upgraded into 677,739 tons of UAN. Pet coke is a low value by-product of the refinery coking process. On average during the last five years, 73% 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 pet coke supply agreement with the petroleum business.

The nitrogen fertilizer plant is the only commercial facility in North America utilizing a pet coke gasification process to produce nitrogen fertilizers. Its redundant train gasifier provides good on-stream reliability and uses low cost by-product pet coke feed (rather than natural gas) to produce hydrogen. In times of high natural gas prices, the use of low cost pet coke can provide us with a significant competitive advantage. The nitrogen fertilizer business' competition utilizes natural gas to produce ammonia. Historically, pet coke has generally been a less expensive feedstock than natural gas on a per-ton of fertilizer produced basis.

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, including the supply of and demand for crude oil, as well as gasoline and other refined products which, in turn, depend on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and the extent of government regulation. 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, 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 addition to current market conditions, there are long-term factors that may impact the demand for refined products. These factors include mandated renewable fuel standards, proposed climate change laws and regulations, and increased mileage standards for vehicles.

In order to assess our operating performance, we compare our net sales, less cost of product sold, or our refining margin, against an industry refining margin benchmark. The industry refining margin is calculated by assuming that two barrels of benchmark light sweet crude oil is converted 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. The 2-1-1 crack spread is expressed in dollars per barrel and is a proxy for the per barrel margin that a sweet crude oil refinery would earn assuming it produced and sold the benchmark production of gasoline and distillate.

Although the 2-1-1 crack spread is a benchmark for our refinery margin, because our refinery has certain feedstock costs and logistical advantages as compared to a benchmark refinery and our product yield is less than total refinery throughput, the crack spread does not account for all the factors that affect refinery margin. Our refinery is able to process a blend of crude oil that includes quantities of heavy and medium sour crude oil that has historically cost less than WTI. 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 oil differential. Our refinery margin can be impacted significantly by the consumed crude oil differential. Our consumed crude oil differential will move directionally with changes in the 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. The correlation between our consumed crude oil differential and published differentials will vary depending on the volume of light medium sour crude oil and heavy sour crude oil we purchase as a percent of our total crude oil volume and will correlate more closely with such published differentials the heavier and more sour the crude oil slate.

We produce a high volume of high value products, such as gasoline and distillates. We benefit from the fact that our marketing region consumes more refined products than it produces so that the market prices 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 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 both gasoline and Ultra Low Sulfur Diesel basis are greater than zero, this means that prices in our marketing area exceed those used in the 2-1-1 crack spread.

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 and a temporary increase in working capital investment and related inventory position. We seek to mitigate the financial impact of planned downtime, such as major turnaround maintenance, through a diligent planning process that takes into account the margin environment, the availability of resources to perform the needed maintenance, feedstock logistics and other factors. The refinery generally undergoes a facility turnaround every four to five years. The length of the turnaround is contingent upon the scope of work to be completed.

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

Nitrogen Fertilizer Business

In the nitrogen fertilizer business, earnings and cash flow from operations are primarily affected by the relationship between nitrogen fertilizer product prices and direct operating expenses. Unlike its competitors, the nitrogen fertilizer business uses minimal natural gas as feedstock and, as a result, is not directly impacted in terms of cost, by volatile swings in natural gas prices. Instead, our adjacent refinery supplies most of the pet coke feedstock needed by the nitrogen fertilizer business pursuant to a long-term pet coke supply agreement we entered into in October 2007. The price at which nitrogen fertilizer products are ultimately sold depends on numerous factors, including the global supply and demand for nitrogen fertilizer products which, in turn, depends 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. Nitrogen fertilizer prices are also affected by other factors, such as local market conditions and the operating levels of competing facilities. An expansion or upgrade of competitors' facilities, 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.

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

Natural gas is the most significant raw material required in our competitors' production of nitrogen fertilizers. Over the past several years, natural gas prices have experienced high levels of price volatility. This pricing and volatility has a direct impact on our competitors' cost of producing nitrogen fertilizer.

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.

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 U.S. Gulf Coast 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 producers and 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 2009, the nitrogen fertilizer business upgraded approximately 64% 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, and outside services. These costs comprise the fixed costs associated with the nitrogen fertilizer plant.

The nitrogen fertilizer business' largest raw material expense is pet coke, which it purchases from the petroleum business and third parties. In 2009, the nitrogen fertilizer business spent $12.8 million for pet coke. If pet coke prices rise substantially in the future, the nitrogen fertilizer business may be unable to increase its prices to recover increased raw material costs, because the price floor for nitrogen fertilizer products is generally correlated with natural gas prices, the primary raw material used by its competitors, and not pet coke prices.

Consistent, safe, and reliable operations at the nitrogen fertilizer plant are critical to its financial performance and results of operations. Unplanned downtime of the nitrogen fertilizer plant may result in lost margin opportunity, increased maintenance expense and a temporary increase in working capital investment and related inventory position. The financial impact of planned downtime, such as major turnaround maintenance, is mitigated through a diligent planning process that takes into account margin environment, the availability of resources to perform the needed maintenance, feedstock logistics and other factors. The nitrogen fertilizer plant generally undergoes a facility turnaround every two years. The turnaround typically lasts 13-15 days each turnaround year and costs approximately $3 million to $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

Until October 8, 2009, CRLLC had been a party to the Cash Flow Swap with J. Aron, a subsidiary of The Goldman Sachs Group, Inc. and a related party of ours. On October 8, 2009, the Cash Flow Swap was terminated and all remaining obligations were settled in advance. We have determined that the Cash Flow Swap did not qualify as a hedge for hedge accounting treatment under Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 815, *Derivatives and Hedging*. As a result, the Consolidated Statement of Operations reflects all the realized and unrealized gains and losses from this swap which has created significant changes between periods. As a result of the termination of the Cash Flow Swap in the fourth quarter of 2009, there was no impact recorded in the three and six months ended June 30, 2010 compared to net realized and unrealized losses of $22.6 million and $58.4 million for the three and six months ended June 30, 2009.

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 FASB ASC 718, *Compensation — Stock Compensation*, the expense associated with these awards 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 an accounting standard issued by the FASB which provides guidance regarding the accounting treatment by an investor for stock-based compensation granted to employees of an equity method investee. In addition, these awards are subject to an accounting standard issued by the FASB which provides guidance regarding the accounting treatment for equity instruments that are issued to other than employees for acquiring or in conjunction with selling goods or services. In accordance with this 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 months ended June 30, 2010, we reversed compensation expense by $3.0 million as a result of the phantom and override unit share-based compensation awards. For the three months ended June 30, 2009, we increased compensation expense by $5.5 million, as a result of the phantom and override unit share-based compensation awards. For the six months ended June 30, 2010 and 2009, we increased compensation expense by $4.1 million and $9.3 million, respectively, as a result of the phantom and override unit share-based compensation awards. We expect to incur additional incremental share-based compensation expense to the extent our common stock price increases.

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, 2010 and 2009. 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, 2009, is unaudited.

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited) (in millions, except share data)			
Consolidated Statement of Operations Data				
Net sales	$ 1,005.9	$ 793.3	$ 1,900.4	$ 1,402.7
Cost of product sold(1)	891.7	587.6	1,694.5	1,009.2
Direct operating expenses(1)	62.5	54.5	123.1	110.7
Selling, general and administrative expenses(1)	10.8	21.8	32.2	41.3
Net costs associated with flood(2)	—	(0.1)	—	0.1
Depreciation and amortization(3)	21.5	21.1	42.8	42.0
Operating income	$ 19.4	$ 108.4	$ 7.8	$ 199.4
Other income, net	1.5	0.9	1.9	0.9
Interest expense and other financing costs	(12.8)	(11.2)	(22.7)	(22.7)
Gain (loss) on derivatives, net	7.3	(29.2)	8.8	(66.1)
Loss on extinguishment of debt	(14.6)	(0.7)	(15.1)	(0.7)
Income (loss) before income tax expense (benefit)	$ 0.8	$ 68.2	$ (19.3)	$ 110.8
Income tax expense (benefit)	(0.4)	25.5	(8.1)	37.5
Net income (loss)(4)	$ 1.2	$ 42.7	$ (11.2)	$ 73.3
Basic earnings (loss) per share	$ 0.01	$ 0.49	$ (0.13)	$ 0.85
Diluted earnings (loss) per share	$ 0.01	$ 0.49	$ (0.13)	$ 0.85
Weighted-average common shares outstanding:				
Basic	86,336,125	86,244,152	86,332,700	86,243,949
Diluted	86,506,590	86,333,349	86,332,700	86,327,911

	As of June 30, 2010	As of December 31, 2009
	(unaudited)	
	(in millions)	
Balance Sheet Data		
Cash and cash equivalents	$ 63.3	$ 36.9
Working capital	265.4	235.4
Total assets	1,620.7	1,614.5
Total debt, including current portion	500.9	491.3
Total CVR stockholders' equity	645.3	653.8

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited) (in millions)			
Cash Flow Data				
Net cash flow provided by (used in):				
Operating activities	$ 2.2	$ 54.8	$ 45.7	$ 91.5
Investing activities	(5.4)	(8.7)	(16.8)	(24.6)
Financing activities	28.9	(1.2)	(2.5)	(2.5)
Other Financial Data				
Capital expenditures for property, plant and equipment	$ 5.4	$ 8.7	$ 16.8	$ 24.6
Depreciation and amortization	21.5	21.1	42.8	42.0

(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 and administrative expenses:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited) (in millions)			
Depreciation and amortization excluded from cost of product sold	$ 0.7	$ 0.7	$ 1.5	$ 1.4
Depreciation and amortization excluded from direct operating expenses	20.3	19.9	40.3	39.7
Depreciation and amortization excluded from selling, general and administrative expenses	0.5	0.5	1.0	0.9
Total depreciation and amortization	$ 21.5	$ 21.1	$ 42.8	$ 42.0

(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 Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited) (in millions)			
Loss on extinguishment of debt(a)	$ 14.6	$ 0.7	$ 15.1	$ 0.7
Letter of credit expense and interest rate swap not included in interest expense(b)	1.5	3.6	3.8	7.9
Unrealized net (gain) loss from Cash Flow Swap	—	19.9	—	40.0
Share-based compensation expense(c)	(2.8)	5.6	4.4	9.5

(a) In January 2010, we made a voluntary unscheduled principal payment of $20.0 million on our tranche D term loans. In addition, we made a second voluntary unscheduled principal payment of $5.0 million in February 2010. In connection with these voluntary prepayments, we paid a 2.0% premium totaling $0.5 million to the lenders of our first priority credit facility. The premiums paid are reflected as a loss on extinguishment of debt in our Condensed Consolidated Statements of Operations. In April 2010, we paid off the remaining $453.0 million tranche D term loans. This payoff was made possible by the issuance of $275.0 million aggregate principal amount of 9.0% First Lien Senior Secured Notes due 2015 (the "First Lien Notes") and $225.0 million aggregate principal amount of 10.875% Second Lien Senior Secured Notes due 2017 (the "Second Lien Notes" and together with the First Lien Notes, the "Notes"). In connection with the payoff, we paid a 2.0% premium totaling approximately $9.1 million. In addition, previously deferred borrowing costs totaling approximately $5.4 million associated with the first priority credit facility term debt were also written off at that time. The Company also recognized approximately $0.1 million of third party costs at the time the Notes were issued. Other third party costs incurred at the time were deferred and will be amortized over the respective terms of the Notes. The premiums paid, previously deferred borrowing costs subject to write-off and immediately recognized third party expenses are reflected as a loss on extinguishment of debt in our Condensed Consolidated Statements of Operations. For the three and six months ended June 30, 2009, the $0.7 million loss on extinguishment of debt 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 issued in support of the Cash Flow Swap, terminated effective October 8, 2009, as well as other letters of credit outstanding. 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 first priority credit facility.

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

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,	
	2010	2009	2010	2009
	(unaudited) (in millions, except as otherwise indicated)			
Petroleum Business Financial Results				
Net sales	$ 951.3	$ 740.0	$ 1,808.0	$ 1,285.2
Cost of product sold(1)	882.1	581.7	1,681.1	999.3
Direct operating expenses(1)(2)(3)	41.2	33.0	79.5	67.6
Net costs associated with flood	—	(0.1)	—	0.1
Depreciation and amortization	16.4	16.0	32.6	31.8
Gross profit(4)	$ 11.6	$ 109.4	$ 14.8	$ 186.4
Plus direct operating expenses(1)	41.2	33.0	79.5	67.6
Plus net costs associated with flood	—	(0.1)	—	0.1
Plus depreciation and amortization	16.4	16.0	32.6	31.8
Refining margin(5)	69.2	158.3	126.9	285.9
Operating income (loss)	$ 4.6	$ 96.2	$ (2.4)	$ 160.9
Key Operating Statistics				
Per crude oil throughput barrel:				
Refining margin(5)	$ 6.70	$ 15.58	$ 6.41	$ 14.50
Gross profit(4)	$ 1.13	$ 10.77	$ 0.75	$ 9.46
Direct operating expenses(1)(2)	$ 3.99	$ 3.25	$ 4.02	$ 3.43
Direct operating expenses per barrel sold(1)(3)	$ 3.63	$ 2.90	$ 3.63	$ 3.03
Barrels sold (barrels per day)(3)	124,486	125,121	121,016	123,305

	Three Months Ended June 30, 2010	%	2009	%	Six Months Ended June 30, 2010	%	2009	%
Refining Throughput and Production Data (bpd)								
Throughput:								
Sweet	90,829	74.5	87,610	70.8	87,864	74.8	81,319	66.5
Light/medium sour	8,505	7.0	16,245	13.1	8,019	6.8	18,477	15.1
Heavy sour	14,097	11.6	7,765	6.3	13,425	11.4	9,114	7.5
Total crude oil throughput	113,431	93.1	111,620	90.2	109,308	93.0	108,910	89.1
All other feedstocks and blendstocks	8,436	6.9	12,097	9.8	8,209	7.0	13,290	10.9
Total throughput	121,867	100.0	123,717	100.0	117,517	100.0	122,200	100.0
Production:								
Gasoline	55,998	45.7	63,170	51.0	57,508	48.5	63,745	52.1
Distillate	51,008	41.6	48,192	38.9	48,137	40.6	47,194	38.6
Other (excluding internally produced fuel)	15,607	12.7	12,529	10.1	12,911	10.9	11,338	9.3
Total refining production (excluding internally produced fuel)	122,613	100.0	123,891	100.0	118,556	100.0	122,277	100.0
Product price (dollars per gallon):								
Gasoline	$ 2.12		$ 1.70		$ 2.08		$ 1.47	
Distillate	$ 2.17		$ 1.57		$ 2.12		$ 1.46	

	Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Market Indicators (dollars per barrel)				
West Texas Intermediate (WTI) NYMEX	$ 78.05	$ 59.79	$ 78.46	$ 51.68
Crude Oil Differentials:				
WTI less WTS (light/medium sour)	1.84	1.39	1.86	1.16
WTI less WCS (heavy sour)	13.92	9.19	12.19	8.20
NYMEX Crack Spreads:				
Gasoline	13.00	12.23	11.39	10.68
Heating Oil	10.50	5.74	8.89	9.37
NYMEX 2-1-1 Crack Spread	11.75	8.99	10.14	10.03
PADD II Group 3 Basis:				
Gasoline	(2.88)	(1.73)	(2.80)	(1.19)
Ultra Low Sulfur Diesel	2.58	0.53	1.13	(0.63)
PADD II Group 3 Product Crack:				
Gasoline	10.12	10.51	8.58	9.49
Ultra Low Sulfur Diesel	13.08	6.27	10.03	8.75
PADD II Group 3 2-1-1	11.60	8.39	9.31	9.12

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

(2) Direct operating expense is presented on a per crude oil throughput basis. 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 to derive the metric.

(3) Direct operating expense is presented on a per barrel sold basis. Barrels sold are derived from the barrels produced and shipped from the refinery. We utilize the total direct operating expenses, which does not include depreciation or amortization expense, and divide by the applicable number of barrels sold for the period to derive the metric.

(4) 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.

(5) Refining margin per crude oil throughput barrel 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 Condensed 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.

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,	
	2010	2009	2010	2009
	(unaudited) (in millions)			
Nitrogen Fertilizer Business Financial Results				
Net sales	$ 56.3	$ 55.3	$ 94.6	$ 123.1
Cost of product sold(1)	11.9	8.2	16.9	16.9
Direct operating expenses(1)	21.3	21.5	43.5	43.1
Net costs associated with flood	—	—	—	—
Depreciation and amortization	4.7	4.7	9.3	9.3
Operating income	$ 16.5	$ 16.5	$ 19.5	$ 45.8

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	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited)			
Key Operating Statistics				
Production (thousand tons):				
Ammonia (gross produced)(2)	105.2	103.3	210.3	211.3
Ammonia (net available for sale)(2)	38.7	38.9	76.9	77.8
UAN	162.9	156.1	326.7	325.8
Pet coke consumed (thousand tons)	115.5	114.3	233.1	239.6
Pet coke (cost per ton)	$ 17	$ 32	$ 15	$ 34
Sales (thousand tons)(3):				
Ammonia	50.6	27.4	81.8	75.4
UAN	172.2	161.8	327.9	304.7
Total sales	222.8	189.2	409.7	380.1
Product pricing (plant gate) (dollars per ton)(3):				
Ammonia	$ 312	$ 351	$ 300	$ 365
UAN	$ 205	$ 249	$ 187	$ 280
On-stream factor(4):				
Gasification	92.2%	91.7%	94.0%	95.8%
Ammonia	90.4%	89.5%	92.3%	94.7%
UAN	89.1%	87.4%	89.8%	91.7%
Reconciliation to net sales (dollars in millions):				
Freight in revenue	$ 5.2	$ 5.5	$ 8.8	$ 9.6
Hydrogen revenue	—	—	—	0.7
Sales net plant gate	51.1	49.8	85.8	112.8
Total net sales	$ 56.3	$ 55.3	$ 94.6	$ 123.1

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited)			
Market Indicators				
Natural gas NYMEX (dollars per MMBtu)	$4.35	$3.81	$4.67	$4.13
Ammonia — Southern Plains (dollars per ton)	$ 359	$ 308	$ 345	$ 322
UAN — Mid Cornbelt (dollars per ton)	$ 249	$ 221	$ 246	$ 247

(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. Excluding the impact of the Linde air separation unit outage, the on-stream factors would have been 97.8% for gasifier, 96.8% for ammonia and 95.3% for UAN for the three months ended June 30,

2010. Excluding the impact of the Linde air separation unit outage, the on-stream factors for the six months ended June 30, 2010 would have been 96.9% for gasifier, 95.5% for ammonia and 93.0% for UAN. Excluding the impact of the Linde air separation unit outage, the on-stream factors would have been 99.3% for gasifier, 97.1% for ammonia and 95.1% for UAN for the three months ended June 30, 2009. Excluding the impact of the Linde air separation unit outage, the on-stream factors for the six months ended June 30, 2009 would have been 99.6% for gasifier, 98.6% for ammonia and 95.6% for UAN.

Three Months Ended June 30, 2010 Compared to the Three Months Ended June 30, 2009

Consolidated Results of Operations

Net Sales. Consolidated net sales were $1,005.9 million for the three months ended June 30, 2010 compared to $793.3 million for the three months ended June 30, 2009. The increase of $212.6 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 was primarily due to an increase in petroleum net sales of approximately $211.4 million that resulted from higher product prices ($239.6 million) and partially offset by slightly lower sales volumes ($28.2 million). The increase in petroleum sales were coupled with an increase in nitrogen fertilizer net sales of $1.0 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009. The increase in nitrogen net sales was primarily due to higher overall sales volume ($10.2 million) mostly offset by lower plant gate prices ($9.2 million).

Cost of Product Sold (Exclusive of Depreciation and Amortization). Consolidated cost of product sold (exclusive of depreciation and amortization) was $891.7 million for the three months ended June 30, 2010 as compared to $587.6 million for the three months ended June 30, 2009. The increase of $304.1 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 primarily resulted from an increase in crude oil prices. On a quarter-over-quarter basis, our consumed crude oil costs increased approximately $243.6 million. Consumed crude oil cost per barrel increased 42.7% from an average price of $53.29 per barrel for the three months ended June 30, 2009 to an average price of $76.04 per barrel for the three months ended June 30, 2010.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Consolidated direct operating expenses (exclusive of depreciation and amortization) were $62.5 million for the three months ended June 30, 2010 as compared to $54.5 million for the three months ended June 30, 2009. This increase of $8.0 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 was due to an increase in petroleum direct operating expenses of $8.2 million partially offset by a decrease in nitrogen fertilizer direct operating expenses of $0.2 million. The increase was primarily attributable to increased labor ($3.0 million), repairs and maintenance ($2.6 million), energy and utility costs ($1.9 million), property taxes ($1.1 million) and outside services and other direct operating expenses ($0.7 million). These direct operating expense increases were partially offset by decreases in expenses associated with production chemicals ($0.8 million) and insurance ($0.6 million).

Selling, General and Administrative Expenses (Exclusive of Depreciation and Amortization). Consolidated selling, general and administrative expenses (exclusive of depreciation and amortization) were $10.8 million for the three months ended June 30, 2010 as compared to $21.8 million for the three months ended June 30, 2009. This variance was primarily the result of a decrease in expenses associated with share-based compensation ($8.6 million), bank charges ($1.8 million), bad-debt provision ($0.8 million), payroll ($0.7 million), outside services ($0.6 million) and insurance ($0.3 million). These decreases were partially offset by an increase in asset write-offs ($1.3 million), and other selling, general and administrative expenses ($0.5 million).

Operating Income (loss). Consolidated operating income was $19.4 million for the three months ended June 30, 2010 as compared to an operating income of $108.4 million for the three months ended June 30, 2009. For the three months ended June 30, 2010 as compared to the three months ended June 30, 2009, petroleum operating income decreased $91.6 million while nitrogen fertilizer operating income remained $16.5 million for both the second quarters of 2010 and 2009.

Interest Expense. Consolidated interest expense for the three months ended June 30, 2010 was $12.8 million as compared to interest expense of $11.2 million for the three months ended June 30, 2009. This $1.6 million increase for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 resulted from the issuance of the Notes on April 6, 2010 in an aggregate principal amount of $500.0 million. The proceeds from the Notes were utilized primarily to pay off our existing tranche D term debt. The $275.0 million in First Lien Notes accrue interest at 9.0% and the $225.0 million in Second Lien Notes accrue interest at 10.875%. This compares to an average second quarter 2009 long-term debt balance of $481.9 million at 8.75%. Also impacting interest expense for the three months ended June 30, 2010 is the increased amortization of deferred financing cost. Amortization of deferred financing cost for the three months ended June 30, 2010 totaled $1.1 million compared to $0.5 million for the three months ended June 30, 2009. The increase in amortization for the three months ended June 30, 2010 was the result of cost incurred with the third and fourth amendments to our first priority credit facility and issuance of the Notes. This activity contributed to $0.8 million of additional amortization. This increase was partially offset by the decrease of deferred financing cost amortization associated with the funded letter of credit issued in support of the Cash Flow Swap from $0.3 million for the three months ended June 30, 2009 compared to none for the three months ended June 30, 2010. The funded letter of credit was terminated in the fourth quarter of 2009.

Gain (loss) on Derivatives, net. For the three months ended June 30, 2010, we recorded a $7.3 million gain on derivatives, net compared to a $29.2 million loss on derivatives, net for the three months ended June 30, 2009. The gain on derivatives, net for the three months ended June 30, 2010 as compared to the loss on derivatives, net for the three months ended June 30, 2009 was primarily attributable to the termination of the Cash Flow Swap in the fourth quarter of 2009. The Cash Flow Swap for the three months ended June 30, 2009 contributed realized and unrealized losses of approximately $22.6 million compared to $0 for the three months ended June 30, 2010. Our other derivative agreements provided a net realized and unrealized gain of approximately $7.3 million for the three months ended June 30, 2010 compared to a net realized and unrealized loss of approximately $6.0 million for the three months ended June 30, 2009.

Loss on Extinguishment of Debt. For the three months ended June 30, 2010, we recorded a $14.6 million loss on extinguishment of debt. This compares to a $0.7 million loss on extinguishment of debt for the three months ended June 30, 2009. The loss on extinguishment of debt is the result of the pay off of our tranche D term debt on April 6, 2010. The term debt was paid off with proceeds received from the issuance of the Notes. As a result of this payoff, the Company paid a 2.0% premium to the lenders of the credit facility totaling $9.1 million. In addition, previously deferred borrowing costs totaling approximately $5.4 million were written off and the Company also recognized additional third party expense at the time of the issuance of the Notes of approximately $0.1 million.

Income Tax Expense (benefit). Income tax benefit for the three months ended June 30, 2010 was $0.4 million, or (58.5)% of income before income tax benefit, as compared to income tax expense of $25.5 million, or 37.4% of income before income tax expense, for the three months ended June 30, 2009. The increased income tax benefit rate for the three months ended June 30, 2010 was primarily the result of the receipt and recognition of interest income in the second quarter of 2010 associated with federal income tax refunds received. The correlation of the recognition of the tax affected interest income with the level of pre-tax income increased the effective rate of the tax benefit recorded.

Net Income (loss). For the three months ended June 30, 2010, net income totaled $1.2 million as compared to net income of $42.7 million for the three months ended June 30, 2009. The decrease of $41.5 million for the second quarter of 2010 compared to the second quarter of 2009 was primarily due to a decline in refining margins, an increase in the loss on extinguishment of debt and an increase in direct operating expenses. These impacts were partially offset by a decrease in the loss on derivatives, net in the second quarter of 2009 compared to a gain on derivatives, net for the second quarter of 2010 and a decrease in selling, general and administrative expenses.

Petroleum Business Results of Operations for the Three Months Ended June 30, 2010

Net Sales. Petroleum net sales were $951.3 million for the three months ended June 30, 2010 compared to $740.0 million for the three months ended June 30, 2009. The increase of $211.3 million during the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 was primarily the result of significantly higher product prices ($239.6 million) which was partially offset by lower overall sales volumes ($28.3 million). Our average sales price per gallon for the three months ended June 30, 2010 for gasoline of $2.12 and distillate of $2.17 increased by 24.8% and 38.1%, respectively, as compared to the three months ended June 30, 2009.

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 $882.1 million for the three months ended June 30, 2010 compared to $581.7 million for the three months ended June 30, 2009. The increase of $300.4 million during the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 was primarily the result of a significant increase in crude oil prices. The impact of FIFO accounting also impacted cost of product sold during the comparable periods. Our average cost per barrel of crude oil consumed for the three months ended June 30, 2010 was $76.04 compared to $53.29 for the comparable period of 2009, an increase of 42.7%. Sales volume of refined fuels decreased by approximately 3.1% for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009. 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 three months ended June 30, 2010, we had an unfavorable FIFO inventory impact of $17.5 million compared to a favorable FIFO inventory impact of $67.3 million for the comparable period of 2009.

Refining margin per barrel of crude throughput decreased from $15.58 for the three months ended June 30, 2009 to $6.70 for the three months ended June 30, 2010. Gross profit per barrel decreased to $1.13 in the second quarter of 2010 as compared to gross profit per barrel of $10.77 in the equivalent period in 2009. Several factors contributed to the negative variance in refining margin per barrel of crude throughput. One contributing factor was the decrease in our consumed crude oil differential over the comparable periods. Our consumed crude oil differential for the three months ended June 30, 2010 was $(1.77) per barrel as compared to $(6.38) per barrel for the three months ended June 30, 2009. This was the result of our processing a sweeter crude slate in the three months ended June 30, 2010 (approximately 80% sweet crude) as compared to the three months ended June 30, 2009 (approximately 78% sweet crude) and an unfavorable FIFO inventory impact. Our FIFO impact was unfavorable for the three months ended June 30, 2010 due to the approximately $8.10 per barrel decline in the crude oil price from the beginning of the quarter to the end of the quarter. Conversely, the crude oil price rose approximately $20.20 per barrel in the comparable period of 2009 creating a favorable FIFO inventory impact. The negative regional differences between gasoline prices in our primary marketing region (the Coffeyville supply area) and that of the NYMEX also negatively impacted refining margin per barrel over the comparable periods. The average gasoline basis for the three months ended June 30, 2010 decreased by $1.15 per barrel to $(2.88) per barrel compared to $(1.73) per barrel in the comparable period of 2009. Partially offsetting these negative impacts was an increase in the NYMEX 2-1-1 crack spread and an increase in the average ultra low sulfur diesel basis. The average NYMEX 2-1-1 crack spread increased to $11.75 per barrel for the three months ended June 30, 2010 from $8.99 per barrel in the comparable period of 2009. The average ultra low sulfur diesel basis increased by $2.05 per barrel to $2.58 per barrel for the three months ended June 30, 2010 compared to $0.53 per barrel in the comparable period of 2009.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Direct operating expenses for our petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance, labor and environmental compliance costs. Petroleum direct operating expenses (exclusive of depreciation and amortization) were $41.2 million for the three months ended June 30, 2010 compared to direct operating expenses of $33.0 million for the three months ended June 30, 2009. The increase of $8.2 million for the three months ended June 30, 2010 compared to the three months ended June 30, 2009, was the result of increases in expenses primarily associated with repairs and maintenance ($4.0 million), labor ($3.0 million), utilities and energy costs ($1.6 million) and other direct operating expenses ($0.9 million). Increases in direct operating expenses were partially offset by decreases in expenses primarily associated with chemicals ($0.8 million), insurance ($0.3 million) and royalties ($0.2 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude oil throughput for the three months ended June 30, 2010 increased to $3.99 per barrel as compared to $3.25 per barrel for the three months ended June 30, 2009.

Operating Income (loss). Petroleum operating income was $4.6 million for the three months ended June 30, 2010 as compared to operating income of $96.2 million for the three months ended June 30, 2009. This decrease of $91.6 million from the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 was primarily the result of a decline in the refining margin ($89.1 million) and an increase in direct operating expenses ($8.2 million). The decrease in refining margin and increase in direct operating expenses were partially offset by a decrease in selling, general and administrative expenses ($6.3 million) which was primarily the result of a decrease in costs associated with share-based compensation.

Nitrogen Fertilizer Business Results of Operations for the Three Months Ended June 30, 2010

Net Sales. Nitrogen fertilizer net sales were $56.3 million for the three months ended June 30, 2010 compared to $55.3 million for the three months ended June 30, 2009. The increase of $1.0 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 was the result of higher product sales volume ($10.2 million) that were mostly offset by lower average plant gate prices ($9.2 million).

In regard to product sales volumes for the three months ended June 30, 2010, our nitrogen fertilizer operations experienced an increase of 85% in ammonia sales unit volumes and an increase of 6% in UAN sales unit volumes. The increase in ammonia sales for the second quarter of 2010 compared to the second quarter of 2009 was primarily attributable to wet weather conditions in March 2010. Sales of ammonia that generally take place late in the first quarter were delayed and therefore increased the second quarter ammonia sales volume. The increase in UAN sales volume in the second quarter of 2010 compared to the second quarter of 2009 was primarily attributable to high priced UAN inventory held by distributors and dealers in the first and second quarters of 2009. Much of this inventory was purchased when prices reached record levels in 2008. As market prices declined, distributors and dealers continued to try to sell this higher priced carryover inventory which led to lower UAN sales volume in second quarter of 2009. On-stream factors (total number of hours operated divided by total hours in the reporting period) for the gasification, ammonia and UAN units were slightly higher than the comparable period with the units reporting 92.2%, 90.4% and 89.1%, respectively, on-stream for the three months ended June 30, 2010. Although the on-stream factors for the three months ending June 30, 2010 continue to demonstrate reliability, 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, 2010 for ammonia were lower than the comparable period of 2009 by 11%. Plant gate prices for the three months ended June 30, 2010 for UAN were lower than plant gate prices for the comparable period of 2009 by 17%. The decline in ammonia and UAN prices on a quarter-over-quarter basis was primarily attributable to the fact that 2009 market prices for these commodities were still decreasing from unprecedented highs in 2008. High priced orders booked in 2008 were continuing to be shipped in the first and second quarters of 2009.

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, 2010 was $11.9 million compared to $8.2 million for the three months ended June 30, 2009. The increase of $3.7 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 was primarily the result of an increase in expenses associated with changes in inventory ($5.2 million) and distribution costs ($0.3 million). These increases were partially offset by a decrease in expenses associated with petroleum coke ($1.8 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 and environmental compliance costs. Nitrogen fertilizer direct operating expenses (exclusive of depreciation and amortization) for the three months ended June 30, 2010 were $21.3 million as compared to $21.5 million for the three months ended June 30, 2009. The decrease of $0.2 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 was primarily the result of decreases in expenses associated with repairs and maintenance ($1.4 million), insurance ($0.3 million) and outside services and other direct operating expenses ($0.1 million). These decreases in direct operating expenses were partially offset by increases in expenses associated with property taxes ($1.1 million), utilities ($0.3 million), and catalyst and production chemicals ($0.2 million).

Operating Income. Nitrogen fertilizer operating income was $16.5 million for the three months ended June 30, 2010 as compared to operating income of $16.5 million for the three months ended June 30, 2009. Operating income was consistent on a quarter-over-quarter basis despite a decline in the nitrogen fertilizer margin ($2.6 million). The decrease in margin was partially offset by a decrease in selling, general and administrative expense ($2.4 million). For the three months ended June 30, 2010 as compared to the three months ended June 30, 2009 direct operating expenses (exclusive of depreciation and amortization) decreased slightly ($0.2 million) and depreciation and amortization was consistently $4.7 million for the second quarter of 2010 and 2009.

Six Months Ended June 30, 2010 Compared to the Six Months Ended June 30, 2009

Consolidated Results of Operations

Net Sales. Consolidated net sales were $1,900.4 million for the six months ended June 30, 2010 compared to $1,402.7 million for the six months ended June 30, 2009. The increase of $497.7 million for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was primarily due to an increase in petroleum net sales of $522.8 million that resulted from significantly higher product prices ($548.6 million), partially offset by slightly lower sales volume ($25.8 million). Nitrogen fertilizer net sales decreased ($28.5 million) for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 due to lower plant gate prices ($35.4 million) partially offset by higher sales volume ($6.9 million).

Cost of Product Sold (Exclusive of Depreciation and Amortization). Consolidated cost of product sold (exclusive of depreciation and amortization) was $1,694.5 million for the six months ended June 30, 2010 as compared to $1,009.2 million for the six months ended June 30, 2009. The increase of $685.3 million for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was primarily due to a significant increase in raw material cost, primarily crude oil. Our average cost per barrel of crude oil for the six months ended June 30, 2010 was $75.98 compared to $45.27 for the comparable period of 2009, an increase of 67.8%. Sales volume of refined fuels decreased by approximately 1% for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Consolidated direct operating expenses (exclusive of depreciation and amortization) were $123.1 million for the six months ended June 30, 2010 as compared to $110.7 million for the six months ended June 30, 2009. This increase of $12.4 million for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was due to an increase in petroleum direct operating expenses of $11.9 million coupled with an increase of $0.4 million in nitrogen direct operating expenses. The increase was primarily related to energy and utilities ($5.2 million), repairs and maintenance ($4.5 million), labor ($3.9 million), property taxes ($1.4 million) and outside services and other direct operating expenses ($0.8 million). These increases were partially offset by decreases in production chemical costs ($2.4 million) and insurance ($1.1 million).

Selling, General and Administrative Expenses (Exclusive of Depreciation and Amortization). Consolidated selling, general and administrative expenses were $32.2 million for the six months ended June 30, 2010 as compared to $41.3 million for the six months ended June 30, 2009. This variance was primarily the result of a decrease in expenses associated with share-based compensation ($5.2 million), bank charges ($3.9 million), administrative payroll ($1.1 million), provision for bad debt ($0.7 million) and insurance ($0.5 million). These decreases were partially offset by increases in an asset write-off ($1.6 million) and a net increase in other selling, general and administrative costs ($0.7 million).

Operating Income (loss). Consolidated operating income was $7.8 million for the six months ended June 30, 2010 as compared to operating income of $199.4 million for the six months ended June 30, 2009. For the six months ended June 30, 2010 as compared to the six months ended June 30, 2009, petroleum operating income decreased by $163.3 million and nitrogen fertilizer operating income decreased by $26.3 million.

Interest Expense. Consolidated interest expense for the six months ended June 30, 2010 was $22.7 million as compared to interest expense of $22.7 million for the six months ended June 30, 2009. Though interest expense for the six months ended June 30, 2010 was consistent with the comparable period in 2009, the drivers behind interest expense were different. We paid off our outstanding tranche D term debt totaling $453.3 million in April 2010 as a result of the issuance of the Notes. The Notes have a principal amount of $500.0 million and were issued under a first and second lien arrangement. The $275.0 million of First Lien Notes accrue interest at 9.0% and the $225.0 million of Second Lien Notes accrue interest at 10.875%. This compares to an average long-term debt balance of $482.5 million and weighted-average interest rate of 8.75% for the six months ended June 30, 2009. Also impacting our interest expense is capitalized interest, as well as additional amortization of deferred financing costs. For the six months ended June 30, 2010, capitalized interest totaled $1.6 million compared to $0.8 million for the six months ended June 30, 2009. For the six months ended June 30, 2010, amortization of deferred financing cost totaled $1.5 million compared to $1.1 million for the six months ended June 30, 2009. The increase in amortization for the six months ended June 30, 2010 was the result of additional financing and underwriting cost incurred with the third and fourth amendments to our first priority credit facility and issuance of the Notes. This activity contributed to $1.2 million of the additional amortization. This increase was partially offset by the decrease of deferred financing cost amortization associated with the funded letter of credit issued in support of the Cash Flow Swap from $0.7 million for the six months ended June 30, 2009 compared to none for the six months ended June 30, 2010. This funded letter of credit was terminated in the fourth quarter of 2009.

Gain (loss) on Derivatives, net. For the six months ended June 30, 2010, we recorded an $8.8 million gain on derivatives, net compared to a $66.1 million loss on derivatives, net for the six months ended June 30, 2009. The gain on derivatives, net for the three months ended June 30, 2010 as compared to the loss on derivatives, net for the six months ended June 30, 2009 was primarily attributable to the termination of the Cash Flow Swap in the fourth quarter of 2009. The Cash Flow Swap for the six months ended June 30, 2009 contributed realized and unrealized losses of approximately $58.4 million compared $0 for the six months ended June 30, 2010. The primary cause of the remaining difference is attributable to an increase in the realized and unrealized gains on other derivative agreements. For the six months ended June 30, 2010, our other derivative agreements generated net gains of $8.9 million compared to net losses on other derivative agreements of $6.9 million for the six months ended June 30, 2009.

Loss on Extinguishment of Debt. For the six months ended June 30, 2010, we recorded a $15.1 million loss on extinguishment of debt. This compares to a $0.7 million loss on extinguishment of debt for the six months ended June 30, 2009. The loss on extinguishment of debt is the result of unscheduled voluntary principal payments on the Company’s long-term tranche D term-debt totaling $25.0 million that occurred in the first quarter of 2010. The unscheduled voluntary payments triggered a 2.0% premium payment to the credit facility lenders that totaled $0.5 million. In addition, we also recorded $14.6 million for loss on extinguishment of debt as the result of the pay off of our remaining $453.3 million tranche D term debt on April 6, 2010. The term debt was paid off with proceeds received from the issuance of the Notes. As a result of this payoff, the

Company paid a 2.0% premium to the lenders of the first priority credit facility totaling $9.1 million. In addition, previously deferred borrowing costs totaling approximately $5.4 million were written off and we also recognized additional third party expense at the time of the issuance of the Notes of approximately $0.1 million.

Income Tax Expense (benefit). Income tax benefit for the six months ended June 30, 2010 was approximately $8.1 million, or 42.0% of loss before income tax benefit, as compared to income tax expense of approximately $37.5 million, or 33.8% of income before income tax expense, for the six months ended June 30, 2009. The increased income tax benefit rate for the six months ended June 30, 2010 was primarily the result of the receipt and recognition of interest income in the second quarter of 2010 associated with federal income tax refunds received. The correlation of the recognition of the tax affected interest income with the pre-tax loss increased the effective rate of the tax benefit recorded. The 2009 tax rate applied to pre-tax income was at a reduced level due to the federal and state income tax credits that were expected to be generated for 2009. There have been no federal or state income tax credits included in the projected annualized effective tax rate for 2010.

Net Income (loss). For the six months ended June 30, 2010, net loss was $11.2 million as compared to $73.3 million of net income for the six months ended June 30, 2009, a decrease of $84.5 million. The decrease in net income for the six months ended June 30, 2010 compared to the six months ended June 30, 2009 was primarily due to the decrease in petroleum and nitrogen fertilizer profit margin, coupled with an increase in direct operating expenses and the loss on extinguishment of debt. These impacts were partially offset by the loss on derivatives, net recorded for the six months ended June 30, 2009 compared to a gain on derivatives, net recorded for the six months ended June 30, 2010.

Petroleum Business Results of Operations for the Six Months Ended June 30, 2010

Net Sales. Petroleum net sales were $1,808.0 million for the six months ended June 30, 2010 compared to $1,285.2 million for the six months ended June 30, 2009. The increase of $522.8 million during the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was primarily the result of significantly higher product prices ($548.6 million) which was partially offset by lower overall sales volumes ($25.8 million). Our average sales price per gallon for the six months ended June 30, 2010 for gasoline of $2.08 and distillate of $2.12 increased by 41.3% and 45.2%, respectively, as compared to the six months ended June 30, 2009.

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 $1,681.1 million for the six months ended June 30, 2010 compared to $999.3 million for the six months ended June 30, 2009. The increase of $681.8 million during the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was primarily the result of a significant increase in crude oil prices. The impact of FIFO accounting also impacted cost of product sold during the comparable periods. Our average cost per barrel of crude oil consumed for the six months ended June 30, 2010 was $75.98 compared to $45.27 for the comparable period of 2009, an increase of 67.8%. Sales volume of refined fuels decreased by approximately 1.4% for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009. 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, 2010, we had an unfavorable FIFO inventory impact of $5.2 million compared to a favorable FIFO inventory impact of $44.7 million for the comparable period of 2009.

Refining margin per barrel of crude throughput decreased from $14.50 for the six months ended June 30, 2009 to $6.41 for the six months ended June 30, 2010. Gross profit per barrel decreased to $0.75 in the second quarter of 2010 as compared to gross profit per barrel of $9.46 in the equivalent period in 2009. Several factors contributed to the negative variance in refining margin per barrel of crude throughput. One contributing factor was the decrease in our consumed crude oil differential over the comparable periods. Our consumed crude oil differential for the six months ended June 30, 2010 was $(2.37) per barrel as compared to $(6.42) per barrel for the six months ended June 30, 2009. This was the result of our processing a sweeter crude slate in the six months ended June 30, 2010 (approximately 80% sweet crude) as compared to the six months ended June 30, 2009 (approximately 75% sweet crude) and an unfavorable FIFO inventory impact. Our FIFO impact was unfavorable for the six months ended June 30, 2010 due to the approximately $3.70 per barrel decline in the crude oil price from the beginning of the period to the end of the period. Conversely, the crude oil price rose approximately $25.30 per barrel in the comparable period of 2009 creating a favorable FIFO inventory impact. The negative regional differences between gasoline prices in our primary marketing region (the Coffeyville supply area) and that of the NYMEX also negatively impacted refining margin per barrel over the comparable periods. The average gasoline basis for the six months ended June 30, 2010 decreased by $1.61 per barrel to $(2.80) per barrel compared to $(1.19) per barrel in the comparable period of 2009. Partially offsetting these negative impacts were an increase in the NYMEX 2-1-1 crack spread and an increase in the average ultra low sulfur diesel basis. The average NYMEX 2-1-1 crack spread increased to $10.14 per barrel for the six months ended June 30, 2010 from $10.03 per barrel in the comparable period of 2009. The average ultra low sulfur diesel basis increased by $1.76 per barrel to $1.13 per barrel for the six months ended June 30, 2010 compared to $(0.63) per barrel in the comparable period of 2009.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Direct operating expenses for our petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance, labor and environmental compliance costs. Petroleum direct operating expenses (exclusive of depreciation and amortization) were $79.5 million for the six months ended June 30, 2010 compared to direct operating expenses of $67.6 million for the six months ended June 30, 2009. The increase of $11.9 million for the six months ended June 30, 2010 compared to the six months ended June 30, 2009, was the result of increases in expenses primarily associated with utilities and energy costs ($5.7 million), labor ($3.9 million), downtime repairs and maintenance ($3.8 million), opportunistic repairs and maintenance ($1.4 million), and rent ($0.8 million). Approximately half of the increase in utilities and energy costs was due to increased natural gas usage and approximately half due to price increases. The increased natural gas usage derived as a result of our increased recovery of saleable liquid barrels from our internally produced fuel system. Increases in direct operating expenses were partially offset by decreases in expenses primarily associated with chemicals ($2.4 million), insurance ($0.6 million), royalties ($0.5 million) and other direct operating expenses ($0.2 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude oil throughput for the six months ended June 30, 2010 increased to $4.02 per barrel as compared to $3.43 per barrel for the six months ended June 30, 2009.

Operating Income (loss). Petroleum operating loss was $2.4 million for the six months ended June 30, 2010 as compared to operating income of $160.9 million for the six months ended June 30, 2009. This decrease of $163.3 million from the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was primarily the result of a decline in the refining margin ($159.0 million), an increase in direct operating expenses ($11.9 million) and an increase in depreciation and amortization ($0.7 million). The decrease in refining margin and increases in direct operating expenses and depreciation and amortization were partially offset by a decrease in selling, general and administrative expenses ($8.3 million) . The decrease in selling, general and administrative expenses was primarily the result of a decrease in costs associated with share-based compensation.

Nitrogen Fertilizer Results of Operations for the Six Months Ended June 30, 2010

Net Sales. Nitrogen fertilizer net sales were $94.6 million for the six months ended June 30, 2010 compared to $123.1 million for the six months ended June 30, 2009. The decrease of $28.5 million for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was the result of lower average plant gate prices ($35.4 million) partially offset by higher product sales volume ($6.9 million).

In regard to product sales volumes for the six months ended June 30, 2010, our nitrogen fertilizer operations experienced an increase of approximately 8% in ammonia sales unit volumes (6,389 tons) and an increase of approximately 8% in UAN sales unit volumes (23,199 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 slightly lower than the on-stream factors for the comparable period. For the six months ended June 30, 2010, the on-stream factors for the gasification, ammonia and UAN units were 94.0%, 92.3% and 89.8%, respectively. 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, 2010 for ammonia were less than plant gate prices for the comparable period of 2009 by approximately 18%. Similarly, UAN plant gate prices for the six months ending June 30, 2010 were approximately 33% lower than the prices of the comparable period of 2009.

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) was $16.9 million for the six months ended June 30, 2010 and the six months ended June 30, 2009. Although cost of product sold (exclusive of depreciation and amortization) remained constant for the comparable periods, specific items impacting costs of product sold fluctuated. For the six months ended June 30, 2010, the nitrogen fertilizer business experienced decreases in pet coke costs ($4.6 million) and freight expense ($0.6 million). These decreases were offset by an increase in costs associated with the change in inventory ($4.0 million), hydrogen ($0.7 million) and distribution costs ($0.4 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, 2010 were $43.5 million as compared to $43.1 million for the six months ended June 30, 2009. The increase of $0.4 million for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was primarily the result of increases in expenses associated with property taxes ($1.2 million), catalyst and other direct operating expenses ($0.5 million) and refractory brick amortization ($0.4 million). These increases were partially offset by a decrease in repairs and maintenance ($0.7 million), utilities ($0.5 million) and insurance ($0.5 million).

Operating Income. Nitrogen fertilizer operating income was $19.5 million for the six months ended June 30, 2010 as compared to $45.8 million for the six months ended June 30, 2009. This decrease of $26.3 million for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was the result of decreased plant gate prices ($35.4 million) partially offset by higher sales volume ($6.9 million). In addition, the nitrogen fertilizer segment's selling, general and administrative costs decreased ($2.5 million) for the six months ended June 30, 2010 compared to the comparable period in 2009.

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, 2010, we had cash and cash equivalents of $63.3 million. As of June 30, 2010 and August 4, 2010, we had no amounts outstanding under our revolving credit facility and aggregate availability of $119.2 million under our revolving credit facility. At August 4, 2010, we had cash and cash equivalents of $111.9 million.

Working capital at June 30, 2010 was $265.4 million, consisting of $451.7 million in current assets and $186.3 million in current liabilities. Working capital at December 31, 2009 was $235.4 million, consisting of $426.0 million in current assets and $190.6 million in current liabilities.

Senior Notes

On April 6, 2010, CRLLC and its newly formed wholly-owned subsidiary, Coffeyville Finance Inc. (together the “Issuers”), completed the private offering of the Notes. The First Lien Notes were issued at 99.511% of their principal amount and the Second Lien Notes were issued at 98.811% of their principal amount.

CRLLC received total net proceeds from the offering of approximately $485.7 million, net of underwriter fees of $10.0 million and original issue discount of approximately $4.0 million, but before deducting other third-party fees and expenses associated with the offering. CRLLC applied the net proceeds to prepay all of the outstanding balance of its tranche D term loan under its first priority credit facility in an amount equal to $453.3 million and to pay related fees and expenses. The balance of the net proceeds were used for general corporate purposes. In accordance with the terms of its first priority credit facility, CRLLC paid a 2.0% premium totaling approximately $9.1 million to the lenders of the term debt upon the prepayment of the outstanding balance. This amount will be recorded as a loss on extinguishment of debt during the second quarter of 2010. Additionally, due to the prepayment and termination of the term debt, a write-off of previously deferred financing charges of approximately $5.4 million will be recorded during the second quarter of 2010. The discount and related debt issuance costs of the Notes are being amortized over the term of the applicable Notes.

The First Lien Notes were issued pursuant to an indenture (the “First Lien Notes Indenture”), dated April 6, 2010, among the Issuers, the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (the “First Lien Notes Trustee”). The Second Lien Notes were issued pursuant to an indenture (the “Second Lien Notes Indenture” and together with the First Lien Notes Indenture, the “Indentures”), dated April 6, 2010, among the Issuers, the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (the “Second Lien Notes Trustee” and in reference to the Indentures, the “Trustee”). The Notes are fully and unconditionally guaranteed by each of the Company’s subsidiaries that also guarantee the first priority credit facility (the “Guarantors” and, together with the Issuers, the “Credit Parties”).

The First Lien Notes bear interest at a rate of 9.0% per annum and mature on April 1, 2015, unless earlier redeemed or repurchased by the Issuers. The Second Lien Notes bear interest at a rate of 10.875% per annum and mature on April 1, 2017, unless earlier redeemed or repurchased by the Issuers. Interest is payable on the Notes semi-annually on April 1 and October 1 of each year, beginning on October 1, 2010, to holders of record at the close of business on March 15 and September 15, as the case may be, immediately preceding each such interest payment date.

The Issuers have the right to redeem the First Lien Notes at the redemption prices set forth below:

- On or after April 1, 2012, some or all of the First Lien Notes may be redeemed at a redemption price of (i) 106.750% of the principal amount thereof, if redeemed during the twelve-moth period beginning on April 1, 2012; (ii) 104.500% of the principal amount thereof, if redeemed during the twelve-month period beginning on April 1, 2013; and (iii) 100% of the principal amount, if redeemed on or after April 1, 2014, in each case, plus any accrued and unpaid interest;

- Prior to April 1, 2012, up to 35% of the First Lien Notes may be redeemed with the proceeds from certain equity offerings at a redemption price of 109.000% of the principal amount thereof, plus any accrued and unpaid interest;
- Prior to April 1, 2012, some or all of the First Lien Notes may be redeemed at a price equal to 100% of the principal amount thereof, plus a make-whole premium and any accrued and unpaid interest; and
- Prior to April 1, 2012, but not more than once in any twelve-month period, up to 10% of the First Lien Notes may be redeemed at a price equal to 103.000% of the principal amount thereof, plus accrued and unpaid interest to the date of redemption.

The Issuers have the right to redeem the Second Lien Notes at the redemption prices set forth below:

- On or after April 1, 2013, some or all of the Second Lien Notes may be redeemed at a redemption price of (i) 108.156% of the principal amount thereof, if redeemed during the twelve-month period beginning on April 1, 2013; (ii) 105.438% of the principal amount thereof, if redeemed during the twelve-month period beginning on April 1, 2014; (iii) 102.719% of the principal amount thereof, if redeemed during the twelve-month period beginning on April 1, 2015; and (iv) 100% of the principal amount if redeemed on or after April 1, 2016, in each case, plus any accrued and unpaid interest;
- Prior to April 1, 2013, up to 35% of the Second Lien Notes may be redeemed with the proceeds from certain equity offerings at a redemption price of 110.875% of the principal amount thereof, plus any accrued and unpaid interest; and
- Prior to April 1, 2013, some or all of the Second Lien Notes may be redeemed at a price equal to 100% of the principal amount thereof, plus a make-whole premium and any accrued and unpaid interest.

In the event of a “change of control” as defined in the Indentures, the Issuers are required to offer to buy back all of the Notes at 101% of their principal amount. A change of control is generally defined as (1) the direct or indirect sale or transfer (other than by a merger) of “all or substantially all of the assets of the Company” to any person other than permitted holders, which are generally GS, Kelso and certain members of management, (2) liquidation or dissolution of CRLLC, (3) any person, other than a permitted holder, directly or indirectly acquiring 50% of the voting stock of CRLLC or (4) the first day when a majority of the directors of CRLLC, CVR Energy are not Continuing Directors (as defined in the Indentures). Continuing Directors are generally our existing directors, directors approved by the then-Continuing Directors or directors nominated or elected by GS or Kelso.

The definition of “change of control” specifically excludes a transaction where CVR Energy becomes a subsidiary of another company, so long as (1) CVR Energy’s shareholders own a majority of the surviving parent or (2) no one person owns a majority of the common stock of the surviving parent following the merger.

The Indentures also allow the Company to sell, spin-off or complete an initial public offering of the Partnership, as long as the Company buys back a percentage of the Notes as described in the Indentures.

The Indentures impose covenants that restrict the ability of the Credit Parties to (i) issue debt, (ii) incur or otherwise cause liens to exist on any of their property or assets, (iii) declare or pay dividends, repurchase equity, or make payments on subordinated or unsecured debt, (iv) make certain investments, (v) sell certain assets, (vi) merge, consolidate with or into another entity, or sell all or substantially all of their assets, and (vii) enter into certain transactions with affiliates. Most of the foregoing covenants would cease to apply at such time that the Notes are rated investment grade by both S&P and Moody’s. However, such covenants would be reinstituted if the Notes subsequently lost their investment grade rating. In addition, the Indentures contain customary events of default, the occurrence of which would result in, or permit the Trustee or holders of at least 25% of the First Lien Notes or Second Lien Notes to cause the acceleration of the applicable Notes, in addition to the pursuit of other available remedies.

The obligations of the Credit Parties under the Notes and the guarantees are secured by liens on substantially all of the Credit Parties' assets. The liens granted in connection with the First Lien Notes are first-priority liens and rank pari passu with the liens granted to the lenders under the first priority credit facility and certain hedge counterparties, including J. Aron. The liens granted in connection with the Second Lien Notes are second-priority liens and rank junior to the aforementioned first-priority liens.

First Priority Credit Facility

As of June 30, 2010, the first priority credit facility consisted of a $150.0 million revolving credit facility. The revolving credit facility provides for direct cash borrowings for general corporate purposes and on a short-term basis. Letters of credit issued under the revolving credit facility are subject to a $100.0 million sub-limit. Outstanding letters of credit reduce the amount available under our revolving credit facility. As of June 30, 2010, we had $30.8 million of outstanding letters of credit consisting of: $0.2 million in letters of credit in support of certain environmental obligations and $30.6 million in letters of credit to secure transportation services for crude oil ($27.4 million of which relates to TransCanada Keystone Pipeline, LP ("TransCanada") petroleum transportation service agreements, the validity of which we are contesting). The revolving loan commitment expires on December 28, 2012. As of June 30, 2010, we had available $119.2 million under the revolving credit facility.

On March 12, 2010, CRLLC entered into a fourth amendment to its first priority credit facility. The amendment, among other things, provided CRLLC the opportunity to issue junior lien debt, subject to certain conditions, including, but not limited to, a requirement that 100% of the proceeds be used to prepay the tranche D term loans. The amendment also provided CRLLC the ability to issue up to $350.0 million of first lien debt, subject to certain conditions, including, but not limited to, a requirement that 100% of the proceeds be used to prepay all of the remaining tranche D term loans.

The amendment also provides financial flexibility to CRLLC through modifications to its financial covenants over the next four quarters and as a result of the Notes issuance on April 6, 2010 the total leverage ratio became a first-lien only test and the interest coverage ratio was further modified. Additionally, the amendment permits CRLLC to re-invest up to $15.0 million of asset sale proceeds each year, so long as such proceeds are re-invested within twelve months of receipt (eighteen months if a binding agreement is entered into within twelve months). CRLLC paid an upfront fee in an amount equal to 0.75% of the aggregate of the approving lenders' loans and commitments outstanding as of March 11, 2010. Additionally, CRLLC paid a fee of $0.9 million in the first quarter of 2010 to a subsidiary of GS in connection with their services as lead bookrunner related to the amendment.

The first priority 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 first priority 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 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 first priority credit facility also requires CRLLC to maintain certain financial ratios as follows:

Fiscal Quarter Ending	Minimum Interest Coverage Ratio(1)	Maximum Leverage Ratio(1)
June 30, 2010	1.50:1.00	4.50:1.00
September 30, 2010	1.50:1.00	4.50:1.00
December 31, 2010	2.00:1.00	4.75:1.00
March 31, 2011 and thereafter	2.00:1.00	2.75:1.00

(1) The minimum interest coverage ratio and maximum leverage ratio presented above represents the adjusted ratios in effect as a result of the issuance of the Notes on April 6, 2010.

The computation of these ratios is governed by the specific terms of the first priority 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 first lien debt to consolidated adjusted EBITDA over a four quarter period. The computation of these ratios requires a calculation of consolidated adjusted EBITDA. In general, under the terms of our first priority credit facility, consolidated adjusted EBITDA is calculated by adding CRLLC consolidated net income (loss), consolidated interest expense, income taxes, depreciation and amortization, other non-cash expenses, any fees and expenses related to permitted acquisitions, any non-recurring expenses incurred in connection with the issuance of debt or equity, management fees, any unusual or non-recurring charges up to 7.5% of CRLLC 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 (loss). As of June 30, 2010, we were in compliance with our covenants under the first priority credit facility.

We present CRLLC consolidated adjusted EBITDA because it is a material component of material covenants within our first priority credit facility and significantly impacts our liquidity and ability to borrow under our revolving line of credit. However, CRLLC consolidated adjusted EBITDA is not a defined term under GAAP and should not be considered as an alternative to operating income or net income as a measure of operating results or as an alternative to cash flows as a measure of liquidity. CRLLC consolidated adjusted

EBITDA is calculated under the first priority credit facility as follows which reconciles CVR consolidated net income (loss) to CRLLC consolidated net income (loss) for the years presented below:

	For the Twelve Months Ended June 30, 2010	For the Twelve Months Ended June 30, 2009
	(unaudited) (in millions)	
Consolidated Financial Results		
CVR net income (loss)	$ (15.2)	$ 184.1
Plus:		
Selling, general and administration at CVR	12.4	10.4
Income tax expense	(16.4)	90.5
Non-cash compensation expense for equity awards	0.9	(4.4)
Unusual or nonrecurring charges	0.4	1.6
Interest income	—	—
CRLLC consolidated net income (loss)	(17.9)	282.2
Plus:		
Depreciation and amortization	85.7	83.5
Interest expense	44.2	42.2
Loss on extinguishment of debt	16.5	10.6
Letters of credit expenses and interest rate swap not included in interest expense	9.3	12.1
Major scheduled turnaround expense	0.2	3.4
Unrealized (gain) or loss on derivatives, net	(4.7)	(241.9)
Non-cash compensation expense for equity awards	2.0	0.1
(Gain) or loss on disposition of fixed assets	0.3	4.3
Unusual or nonrecurring charges	4.6	(1.1)
Property tax — increases due to expiration of abatement	11.4	12.5
FIFO impact (favorable) unfavorable	(15.7)	103.9
Goodwill impairment	—	42.8
CRLLC consolidated adjusted EBITDA	$ 135.9	$ 354.6

Capital Spending

Our total capital expenditures for the three months ended June 30, 2010 totaled $5.4 million, of which approximately $4.1 million was spent for the petroleum business, $0.8 million for the nitrogen fertilizer business and $0.5 million for corporate purposes. For the six months ended June 30, 2010 capital expenditures totaled $16.8 million, of which approximately $13.2 million was spent for the petroleum business, $2.0 million for the nitrogen fertilizer business and $1.6 million for corporate purposes. We divide our capital spending needs into two categories: non-discretionary and discretionary. Non-discretionary capital spending is required to maintain safe and reliable operations or to comply with environmental, health and safety regulations. 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.

Compliance with the Tier II Motor Vehicle Emission Standards Final Rule required us to spend approximately $2.8 million and $9.6 million for the three and six months ended June 30, 2010 and we estimate that compliance will require us to spend approximately $14.0 million in 2010.

Our most recent approved 2010 forecast for consolidated capital expenditures is approximately $53.9 million. In addition, we expect to incur total major scheduled turnaround expenses of approximately $3.8 million for the nitrogen fertilizer business which will occur during the fourth quarter of 2010.

Our planned capital expenditures for 2010 are subject to change due to unanticipated increases in the cost, scope and completion time for our capital projects. For example, we may experience increases in labor and/or equipment costs necessary to comply with government regulations or to complete projects that sustain or improve the profitability of our refinery or nitrogen fertilizer plant. Capital spending for the nitrogen fertilizer business has been and will be determined by the managing general partner of the Partnership.

Cash Flows

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

	Six Months Ended June 30,	
	2010	2009
	(unaudited)	
Net cash provided by (used in):		
Operating activities	$ 45.7	$ 91.5
Investing activities	(16.8)	(24.6)
Financing activities	(2.5)	(2.5)
Net increase in cash and cash equivalents	$ 26.4	$ 64.4

Cash Flows Provided by Operating Activities

Net cash flows provided by operating activities for the six months ended June 30, 2010 was $45.7 million. The positive cash flow from operating activities generated over this period was partially driven by a decrease of inventory, increase in accounts payable and decrease of income tax receivable partially offset by cash outflows for other working capital purposes as well as a net loss for the six months ended June 30, 2010. 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. Trade working capital for the six months ended June 30, 2010 resulted in a cash outflow of $2.4 million, primarily attributable to an increase in accounts receivable ($38.2 million) offset by a decrease of inventories ($23.2 million) and an increase in accounts payable of $11.4 million. Other working capital activities resulted in a net cash outflow of $5.8 million. This outflow was primarily driven by monthly payments totaling $7.5 million related to our insurance premium financing arrangement offset by the receipt of income tax refunds and related interest of approximately $18.1 million. Also impacting other working capital included a $9.2 million decrease in deferred revenue, a $7.6 million increase in personnel accruals and a $5.8 million decrease in other current liabilities.

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. 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. 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.

Cash Flows Used in Investing Activities

Net cash used in investing activities for the six months ended June 30, 2010 was $16.8 million compared to $24.6 million for the six months ended June 30, 2009. The decrease in investing activities for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 was the result of decreased capital expenditures primarily related to the nitrogen fertilizer business. For the six months ended June 30, 2010 capital expenditures for the nitrogen fertilizer business totaled approximately $2.0 million compared to $9.6 million for the six months ended June 30, 2009. This decrease was coupled with a decrease of $0.8 million in petroleum capital expenditures for the comparable periods. For the six months ended June 30, 2010 petroleum capital expenditures totaled approximately $13.2 million compared to $14.0 million for the six months ended June 30, 2009.

Cash Flows Used in Financing Activities

Net cash used in financing activities for the six months ended June 30, 2010 was $2.5 million as compared to net cash used in financing activities of $2.5 million for the six months ended June 30, 2009. During the six months ended June 30, 2010, we paid a $1.2 million scheduled principal payment in January 2010 on long-term debt and then made two voluntary unscheduled principal payments totaling $25.0 million in the first quarter of 2010 related to our long-term debt. On April 6, 2010 we paid off the remaining $453.3 million balance of our outstanding long-term debt. This payoff was the result of the issuances of Notes that resulted in net proceeds of $485.9 million. In addition, we paid $8.7 million of financing costs in connection with the fourth amendment to our first priority credit facility and issuance of the Notes. During the six months ended June 30, 2009, we paid $2.4 million of scheduled principal payments on our long-term debt.

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, 2010 relating to the Notes, operating leases, capital lease obligations, unconditional purchase obligations and other specified capital and commercial commitments for the period following June 30, 2010 and thereafter. As of June 30, 2010, no amounts were outstanding under the $150.0 million first priority credit facility. The following table assumes no borrowings are made under the first priority credit facility.

	Payments Due by Period						
	Total	2010	2011	2012	2013	2014	Thereafter
				(unaudited) (in millions)			
Contractual Obligations							
Notes(1)	$ 500.0	$ —	$ —	$ —	$ —	$ —	$ 500.0
Operating leases(2)	21.1	2.7	5.6	5.6	3.0	2.2	2.0
Capital lease obligations(3)	5.2	0.2	4.9	0.1	—	—	—
Unconditional purchase obligations(4)(5)	283.1	16.5	30.3	27.6	27.7	27.7	153.3
Environmental liabilities(6)	5.2	1.6	0.4	0.4	0.3	0.4	2.1
Interest payments(7)	295.1	23.9	49.2	49.4	49.2	49.2	74.2
Total	$ 1,109.7	$ 44.9	$ 90.4	$ 83.1	$ 80.2	$ 79.5	$ 731.6
Other Commercial Commitments							
Standby letters of credit(8)	$ 30.8	$ —	$ —	$ —	$ —	$ —	$ —

(1) As described above the Company issued the Notes in an aggregate principal amount of $500.0 million on April 6, 2010. The First Lien Notes and Second Lien Notes bear an interest rate of 9.0% and 10.875% per year, payable semi-annually, respectively. The First Lien Notes mature on April 1, 2015, unless earlier redeemed or repurchased by the Issuers. The Second Lien Notes mature on April 1, 2017, unless earlier redeemed or repurchased by the Issuers.

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

(3) The amount includes commitments under capital lease arrangements for real and personal property used for corporate purposes.

(4) The amount includes (a) commitments under several agreements in our petroleum operations related to pipeline usage, petroleum products storage and petroleum transportation and (b) commitments under an electric supply agreement with the city of Coffeyville.

(5) This amount excludes approximately $510.0 million potentially payable under petroleum transportation service agreements between Coffeyville Resources Refining & Marketing, LLC ("CRRM") and TransCanada, pursuant to which CRRM would receive transportation of at least 25,000 barrels per day of crude oil with a delivery point at Cushing, Oklahoma for a term of 10 years on a new pipeline system being constructed by TransCanada. This $510.0 million 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. CRRM filed a Statement of Claim in the Court of the Queen's Bench of Alberta, Judicial District of Calgary, on September 15, 2009, 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 (a) our estimated payments required by federal and/or state environmental agencies related to RCRA at our sites in Coffeyville and Phillipsburg, Kansas and (b) 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.

(7) Interest payments are based on stated interest rates for the respective Notes. Interest is payable on the Notes semi-annually on April 1 and October 1 of each year commencing on October 1, 2010.

(8) Standby letters of credit include $0.2 million of letters of credit issued in connection with environmental liabilities and $30.6 million in letters of credit to secure transportation services for crude oil.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of June 30, 2010.

Recent Accounting Pronouncements

In January 2010, the FASB issued Accounting Standards Update ("ASU") No. 2010-06, "Improving Disclosures about Fair Value Measurements" an amendment to Accounting Standards Codification ("ASC") Topic 820, "Fair Value Measurements and Disclosures." This amendment requires an entity to: (i) disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers, (ii) present separate information for Level 3 activity pertaining to gross purchases, sales, issuances, and settlements and (iii) enhance disclosures of assets and liabilities subject to fair value measurements. The provisions of ASU No. 2010-06 are effective for us for interim and annual reporting beginning after December 15, 2009, with one new disclosure effective after December 15, 2010. We adopted this ASU as of January 1, 2010. The adoption of this standard did not impact our financial position or results of operations.

In June 2009, the FASB issued an amendment to a previously issued standard regarding consolidation of variable interest entities. This amendment was intended to improve financial reporting by enterprises involved with variable interest entities. Overall, the amendment revises the test for determining the primary beneficiary of a variable interest entity from a primarily quantitative analysis to a qualitative analysis. The provisions of the amendment are 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. We adopted this standard as of January 1, 2010. The adoption of this standard did not impact our financial position or results of operations.

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, 2009. 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, 2010 does not differ materially from that discussed under Part II — Item 6A of our Annual Report on Form 10-K for the year ended December 31, 2009. 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.

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, 2010 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, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. *Legal Proceedings*

See Note 11 (“Commitments and Contingent Liabilities”) to Part I, Item I of this Form 10-Q, which is incorporated by reference into this Part II, Item 1, for a description of the Samson and related Sem litigation, TransCanada litigation and Sem preference claim contained in “Litigation” and for a description of the Consent Decree contained in “Environmental, Health, and Safety (“EHS”) Matters.”

Item 1A. *Risk Factors*

As a result of the enactment of financial reform legislation, we have documented below the potential impact of this legislation. This risk factor supplements the risk factors contained in Part I — Item 1A “Risk Factors” of our Annual Report on Form 10-K for the year ended December 31, 2009. Other than with respect to the risk factor set forth below, there have been no material changes from the risk factors disclosed in the “Risk Factors” section of our Annual Report on Form 10-K for the year ended December 31, 2009 and in our Form 10-Q for the quarter ended March 31, 2010.

The enactment of financial reform legislation could have an adverse impact on our ability to hedge risks associated with our business.

On July 21, 2010, President Obama signed the Wall Street and Consumer Protection Act, which will, among other things, impose new requirements and oversight on derivatives transactions, including new clearing and margin requirements. Significant regulations are required to be promulgated by the Commodities Futures Trading Commission (“CFTC”) and the SEC to implement these new requirements. The new requirements, to the extent applicable to the Company, may result in increased costs and cash collateral requirements for the types of commodity derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in crude oil and other inventory prices, and could have an adverse effect on our ability to hedge risks associated with our business.

Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds*

The table below sets forth information regarding repurchases of our common stock during the fiscal quarter ended June 30, 2010. The shares repurchased represent shares of our common stock that employees and directors elected to surrender to the Company to satisfy certain minimum tax withholding and other tax obligations upon the vesting of shares of non-vested stock. The repurchased shares are now held by us as treasury stock. The Company does not consider this to be a share buyback program.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
April 1, 2010 to April 30, 2010	—	—	—	—
May 1, 2010 to May 31, 2010	6,148	$ 8.02	—	—
June 1, 2010 to June 30, 2010	—	—	—	—
Total	6,148	$ 8.02	—	—

Item 6. ***Exhibits***

Number	Exhibit Title
4.1*	Indenture, dated as of April 6, 2010, among Coffeyville Resources, LLC, Coffeyville Finance Inc., the Guarantors (as defined therein) and Wells Fargo Bank, National Association, as Trustee related to $275,000,000 of 9.0% First Lien Senior Secured Notes due 2015 (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K, filed on April 12, 2010 and incorporated herein by reference).
4.1.1*	Form of 9% First Lien Senior Secured Notes due 2015 with attached Form of Notation of Guarantee (filed as Exhibits A1 and E of Exhibit 4.1 hereto, and incorporated herein by reference).
4.2*	Indenture, dated as of April 6, 2010, among Coffeyville Resources, LLC, Coffeyville Finance Inc., the Guarantors (as defined therein) and Wells Fargo Bank, National Association, as Trustee related to $225,000,000 of 10.875% Second Lien Senior Secured Notes due 2017 (filed as Exhibit 1.2 to the Company's Current Report on Form 8-K, filed on April 12, 2010 and incorporated herein by reference).
4.2.1*	Form of 10 7/8% Second Lien Senior Secured Notes due 2017 with attached Form of Notation of Guarantee (filed as Exhibits A1 and E of Exhibit 4.2 hereto, and incorporated herein by reference).
4.3*	Second Lien Pledge and Security Agreement, dated as of April 6, 2010, by and between Coffeyville Resources, LLC, Coffeyville Finance Inc., certain affiliates of Coffeyville Resources, LLC as guarantors and Wells Fargo Bank, National Association, as Collateral Trustee (filed as Exhibit 1.3 to the Company's Current Report on Form 8-K, filed on April 12, 2010 and incorporated herein by reference).
4.4*	Omnibus Amendment Agreement and Consent under the Intercreditor Agreement, dated as of April 6, 2010, by and among Coffeyville Resources, LLC, Coffeyville Finance Inc., Coffeyville Pipeline, Inc., Coffeyville Refining & Marketing, Inc., Coffeyville Nitrogen Fertilizers, Inc., Coffeyville Crude Transportation, Inc., Coffeyville Terminal, Inc., CL JV Holdings, LLC, and certain subsidiaries of the foregoing as Guarantors, the Requisite Lenders, Credit Suisse AG, Cayman Islands Branch, as Administrative Agent, Collateral Agent and Revolving Issuing Bank, J. Aron & Company, as a hedge counterparty and Wells Fargo Bank, National Association, as Collateral Trustee (filed as Exhibit 1.4 to the Company's Current Report on Form 8-K, filed on April 12, 2010 and incorporated herein by reference).
10.1	Fifth Amendment to the Crude Oil Supply Agreement, dated July 19, 2010, between Vitol Inc. and Coffeyville Resources Refining & Marketing, LLC.
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.
*	Previously filed

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.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, 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 6, 2010

By: /s/ Edward Morgan
Chief Financial Officer
(Principal Financial Officer)

August 6, 2010

FIFTH AMENDMENT TO
CRUDE OIL SUPPLY AGREEMENT

THIS FIFTH AMENDMENT TO CRUDE OIL SUPPLY AGREEMENT (this **"Amendment"**) is entered into effective as of July 19, 2010 (the **"Effective Date"**), between Vitol Inc. (**"Vitol"**) and Coffeyville Resources Refining & Marketing, LLC (**"Coffeyville"**).

WHEREAS, Vitol and Coffeyville are parties to a Crude Oil Supply Agreement dated December 2, 2008, as amended pursuant to that certain First Amendment to Crude Oil Supply Agreement dated effective January 1, 2009, that certain Second Amendment to Crude Oil Supply Agreement dated effective July 7, 2009, that certain Third Amendment to Crude Oil Supply Agreement dated effective January 1, 2010, that certain Fourth Amendment to Crude Oil Supply Agreement dated effective January 25, 2010 and as clarified pursuant to that certain Memorandum of Clarification dated December 31, 2008 (such agreement, as amended and clarified, the **"Supply Agreement"**); and

WHEREAS, Vitol and Coffeyville have agreed to further amend certain terms and conditions of the Supply Agreement;

NOW, THEREFORE, in consideration of the premises and the respective promises, conditions, terms and agreements contained herein, and other good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, Vitol and Coffeyville do hereby agree as follows:

1. *Initial Term*. Section 4.1 of the Supply Agreement is amended and restated in its entirety as follows:

   "4.1 *Initial Term*. This Agreement shall become effective on the Effective Date and shall continue until December 31, 2012 (the **"Initial Term"**), unless terminated earlier pursuant to the terms of this Agreement."

2. The definitions contained in the Supply Agreement will have the same meaning in this Amendment unless otherwise stated in this Amendment.

3. Except as otherwise stated in this Amendment, all terms and conditions of the Supply Agreement will remain in full force and effect.

4. This Amendment may be executed by the Parties in separate counterparts and initially delivered by facsimile transmission or otherwise, with original signature pages to follow, and all such counterparts will together constitute one and the same instrument.

5. This Amendment will be governed by, construed and enforced under the laws of the State of New York without giving effect to its conflicts of laws principles.

[Signature Page to Follow]

IN WITNESS WHEREOF, each Party has caused this Amendment to be executed by its duly authorized representative, effective as of the Effective Date.

Vitol Inc.

By: /s/ M.A. Loya
Title: President

Date: 13 July 2010

Coffeyville Resources Refining & Marketing, LLC

By: /s/ John J. Lipinski
Title: CEO

Date: 7/19/10

Exhibit 31.1

Certification by Chief Executive Officer Pursuant to
Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934,
As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, John J. Lipinski, certify that:

1. I have reviewed this report on Form 10-Q of CVR Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ John J. Lipinski
John J. Lipinski
Chief Executive Officer

Date: August 6, 2010

Exhibit 31.2

Certification of Chief Financial Officer Pursuant to
Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934,
As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Edward Morgan, certify that:

1. I have reviewed this report on Form 10-Q of CVR Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ Edward Morgan
Edward Morgan
Chief Financial Officer

Date: August 6, 2010

Exhibit 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

In connection with the filing of the Quarterly Report of CVR Energy, Inc., a Delaware corporation (the "Company") on Form 10-Q for the fiscal quarter ended June 30, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John J. Lipinski, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge and belief:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Report.

By: /s/ John J. Lipinski
John J. Lipinski
Chief Executive Officer

Dated: August 6, 2010

Exhibit 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

In connection with the filing of the Quarterly Report of CVR Energy, Inc., a Delaware corporation (the "Company") on Form 10-Q for the fiscal quarter ended June 30, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Edward Morgan, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge and belief:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Report.

By: /s/ Edward Morgan
Edward Morgan
Chief Financial Officer

Dated: August 6, 2010