CVR ENERGY INC
Form 10-Q
August 08, 2011

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

Form 10-Q

(Mark One)

þ	**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the quarterly period ended June 30, 2011**
	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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 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 þ No o

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

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o (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 þ

There were 86,573,498 shares of the registrant s common stock outstanding at August 2, 2011.

CVR ENERGY, INC. AND SUBSIDIARIES

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For The Quarter Ended June 30, 2011

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GLOSSARY OF SELECTED TERMS

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

2-1-1 crack spread The approximate gross margin resulting from processing two barrels of crude oil to produce one barrel of gasoline and one barrel of 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 capacity. 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.

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.

corn belt The primary corn producing region of the United States, which includes Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Ohio and Wisconsin.

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

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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: 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.

plant gate price the unit price of fertilizer, in dollars per ton, offered on a delivered basis and excluding shipment costs.

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 inspect, refurbish, repair and maintain the refinery or nitrogen fertilizer plant assets. This process involves the shutdown and inspection of major processing units and occurs every four to five years for the refinery and every two years for the nitrogen fertilizer plant.

UAN An aqueous solution of urea and ammonium nitrate used as a fertilizer.

wheat belt The primary wheat producing region of the United States, which includes Oklahoma, Kansas, North Dakota, South Dakota and Texas.

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 between 30 and 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, 2011 (unaudited)	December 31, 2010
	(in thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 747,977	$ 200,049
Accounts receivable, net of allowance for doubtful accounts of $886 and $722, respectively	98,152	80,169
Inventories	315,946	247,172
Prepaid expenses and other current assets	44,923	28,616
Deferred income taxes	15,282	43,351
Total current assets	1,222,280	599,357
Property, plant, and equipment, net of accumulated depreciation	1,061,342	1,081,312
Intangible assets, net	328	344
Goodwill	40,969	40,969
Deferred financing costs, net	16,444	10,601
Insurance receivable	3,856	3,570
Other long-term assets	4,687	4,031
Total assets	$ 2,349,906	$ 1,740,184
LIABILITIES AND EQUITY		
Current liabilities:		
Note payable and capital lease obligations	$ 186	$ 8,014
Accounts payable	165,648	155,220
Personnel accruals	13,954	29,151
Accrued taxes other than income taxes	20,763	21,266
Income taxes payable	38,122	7,983
Deferred revenue	2,988	18,685
Other current liabilities	29,235	25,396
Total current liabilities	270,896	265,715
Long-term liabilities:		

Long-term debt, net of current portion	591,535	468,954
Accrued environmental liabilities, net of current portion	1,797	2,552
Deferred income taxes	348,099	298,943
Other long-term liabilities	17,725	3,847
Total long-term liabilities	959,156	774,296
Commitments and contingencies		
Equity:		
CVR stockholders equity:		
Common Stock $0.01 par value per share, 350,000,000 shares authorized, 86,447,041 and 86,435,672 shares issued, respectively	865	864
Additional paid-in-capital	580,915	467,871
Retained earnings	391,732	221,079
Treasury stock, 12,792 and 21,891 shares, respectively, at cost	(111)	(243)
Accumulated other comprehensive income, net of tax	1	2
Total CVR stockholders equity	973,402	689,573
Noncontrolling interest	146,452	10,600
Total equity	1,119,854	700,173
Total liabilities and equity	$ 2,349,906	$ 1,740,184

See accompanying notes to the condensed consolidated financial statements.

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CVR Energy, Inc. and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(unaudited) (in thousands, except share data)			
Net sales	$ 1,447,716	$ 1,005,898	$ 2,614,981	$ 1,900,410
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	1,123,375	891,652	2,060,197	1,694,542
Direct operating expenses (exclusive of depreciation and amortization)	66,207	62,479	134,533	123,041
Insurance recovery business interruption			(2,870)	
Selling, general and administrative expenses (exclusive of depreciation and amortization)	18,171	10,793	51,433	32,187
Net costs associated with flood			108	
Depreciation and amortization	22,043	21,553	44,054	42,813
Total operating costs and expenses	1,229,796	986,477	2,287,455	1,892,583
Operating income	217,920	19,421	327,526	7,827
Other income (expense):				
Interest expense and other financing costs	(14,205)	(12,766)	(27,395)	(22,688)
Interest income	211	643	485	1,059
Gain (loss) on derivatives, net	6,932	7,339	(15,174)	8,829
Loss on extinguishment of debt	(170)	(14,552)	(2,078)	(15,052)
Other income, net	246	642	477	684
Total other income (expense)	(6,986)	(18,694)	(43,685)	(27,168)
Income (loss) before income tax expense (benefit)	210,934	727	283,841	(19,341)
Income tax expense (benefit)	76,738	(425)	103,857	(8,130)
Net income (loss)	134,196	1,152	179,984	(11,211)
Less: Net income attributable to noncontrolling interest	9,331		9,331	
Net income (loss) attributable to CVR Energy stockholders	$ 124,865	$ 1,152	$ 170,653	$ (11,211)
Basic earnings (loss) per share attributable to CVR Energy stockholders	$ 1.44	$ 0.01	$ 1.97	$ (0.13)
	$ 1.42	$ 0.01	$ 1.94	$ (0.13)

Diluted earnings (loss) per share attributable to CVR Energy stockholders				
Weighted-average common shares outstanding:				
Basic	86,422,881	86,336,125	86,418,356	86,332,700
Diluted	87,789,351	86,506,590	87,786,288	86,332,700

See accompanying notes to the condensed consolidated financial statements.

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CVR Energy, Inc. and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2011	2010
	(unaudited) (in thousands)	
Cash flows from operating activities:		
Net income (loss)	$ 179,984	$ (11,211)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	44,054	42,813
Provision for doubtful accounts	164	(487)
Amortization of deferred financing costs	2,084	1,517
Amortization of original issue discount	255	110
Deferred income taxes	8,122	4,662
Loss on disposition of assets	2,177	1,661
Loss on extinguishment of debt	2,078	15,052
Share-based compensation	21,220	4,434
Unrealized (gain) loss on derivatives	(3,190)	(4,734)
Changes in assets and liabilities:		
Accounts receivable	(18,147)	(38,235)
Inventories	(68,774)	23,216
Prepaid expenses and other current assets	(13,847)	(10,196)
Insurance receivable	(8,969)	
Business interruption insurance proceeds	2,870	
Other long-term assets	(970)	102
Accounts payable	5,187	12,660
Accrued income taxes	30,139	5,248
Deferred revenue	(15,697)	(9,156)
Other current liabilities	(19,226)	8,339
Accrued environmental liabilities	(755)	16
Other long-term liabilities	13,878	(145)
Net cash provided by operating activities	162,637	45,666
Cash flows from investing activities:		
Capital expenditures	(20,979)	(16,826)
Proceeds from the sale of assets	33	
Insurance proceeds from UAN reactor rupture	225	
Net cash used in investing activities	(20,721)	(16,826)
Cash flows from financing activities:		
Revolving debt payments		(60,000)
Revolving debt borrowings		60,000

Proceeds net of original issue discount on issuance of senior notes		485,853
Principal payments on term debt	(2,700)	(479,503)
Payment of financing costs	(10,498)	(8,737)
Payment of capital lease obligation	(4,855)	(40)
Purchase of managing general partner interest and incentive distribution rights	(26,001)	
Proceeds from issuance of CVR Partners long-term debt	125,000	
Proceeds from CVR Partners initial public offering, net of offering costs	325,136	
Payment of treasury stock	(70)	(49)
Net cash provided by (used in) financing activities	406,012	(2,476)
Net increase in cash and cash equivalents	547,928	26,364
Cash and cash equivalents, beginning of period	200,049	36,905
Cash and cash equivalents, end of period	$ 747,977	$ 63,269
Supplemental disclosures:		
Cash paid for income taxes, net of refunds (received)	$ 47,846	$ (18,040)
Cash paid for interest, net of capitalized interest of $939 and $1,647 in 2011 and 2010, respectively	$ 24,333	$ 20,132
Cash funding of margin account for other derivative activities, net of withdrawals (received)	$ (2,909)	$ 2,706
Non-cash investing and financing activities:		
Accrual of construction in progress additions	$ 4,985	$ (1,346)
Reduction of senior notes for underwriting discount and financing costs	$	$ 10,127

See accompanying notes to the condensed consolidated financial statements.

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CVR Energy, Inc. and Subsidiaries

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Common Stockholders								
	Shares Issued	**$0.01 Par Value Common Stock**	**Additional Paid-In Capital**	**Retained Earnings**	**Treasury Stock**	**Accumulated Other Comprehensive Income**	**Total CVR Stockholders' Equity**	**Noncontrolling Interest**	**Total Equit**
	(unaudited) (in thousands, except share data)								
nce at December 31,	86,435,672	$ 864	$ 467,871	$ 221,079	$ (243)	$ 2	$ 689,573	$ 10,600	$ 700,
ct from the issuance /R Partners common to the public			118,213				118,213	136,893	255,
hase of Managing ral Partnership est and incentive bution rights			(15,401)				(15,401)	(10,600)	(26,
e-based compensation			10,434				10,434	228	10,
nce of common stock rectors	3,036								
ng of non-vested awards	8,333	1					1		
nce of stock from ury			(202)		202				
hase of treasury stock					(70)		(70)		
prehensive income:									
ncome				170,653			170,653	9,331	179,
r comprehensive ne, net of tax:									
alized gains (losses) ailable-for sale ities, net of tax						(1)	(1)		
prehensive income							170,652	9,331	179,
nce at June 30, 2011	86,447,041	$ 865	$ 580,915	$ 391,732	$ (111)	$ 1	$ 973,402	$ 146,452	$ 1,119,

See accompanying notes to the condensed consolidated financial statements.

CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2011
(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.

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 wholly-owned subsidiaries, owns the general partner and 69.8% of the common units of CVR Partners, LP, a publicly-traded partnership which 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.

CVR s common stock is listed on the New York Stock Exchange under the symbol CVI. As of December 31, 2010, approximately 40% 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 Kels Funds). On February 8, 2011, GS and Kelso completed a registered public offering, whereby GS sold into the public market its remaining ownership interests in CVR and Kelso substantially reduced its interest in the Company. On May 26, 2011, Kelso completed a registered public offering, whereby Kelso sold into the public market its remaining ownership interests in CVR Energy.

Nitrogen Fertilizer Limited Partnership

In conjunction with the consummation of CVR s initial public offering in 2007, CVR transferred Coffeyville Resources Nitrogen Fertilizers, 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 (LP interest, represented by special LP units). This transfer was not considered a business combination as it was a transfer of assets among entities under common control and, accordingly, balances were transferred at their historical cost. CVR concurrently sold the managing GP interest, including the associated incentive distribution rights (IDRs), to Coffeyville Acquisition III LLC (CALLC III), an entity owned by its then 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 $10.6 million. This interest has been classified as a noncontrolling interest included as a separate component of equity in the Condensed Consolidated Balance Sheets at December 31, 2010. In connection with the April 2011 initial public offering of the Partnership (the Offering), as discussed in further detail below, the IDRs were purchased by the Partnership and the IDRs were subsequently extinguished. In addition, the noncontrolling interest representing the managing GP interest was purchased by Coffeyville Resources, LLC (CRLLC), a subsidiary of CVR. The payment for the IDRs was paid to the owners of CALLC III, which included the Goldman Sachs Funds, the Kelso Funds and members of CVR senior management. As a result of the Offering, the Company recorded a noncontrolling interest for the common units sold into the public market which represented approximately a 30.2% interest in the Partnership at the time of the Offering. The Company s noncontrolling interest reflected on the consolidated balance sheet of CVR will be impacted by the net income of, and distributions from the Partnership.

On April 13, 2011, the Partnership completed its initial public offering (the Offering) of 22,080,000 common units priced at $16.00 per unit (such amount includes common units issued pursuant to the exercise

CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the underwriters over-allotment option). The common units, which are listed on the New York Stock Exchange, began trading on April 8, 2011 under the symbol UAN .

At June 30, 2011, the Partnership had 73,002,956 common units outstanding, consisting of 22,082,956 common units owned by the public, representing 30.2% of the total Partnership units and 50,920,000 common units owned by CRLLC, representing 69.8% of the total Partnership units.

The gross proceeds to the Partnership from the Offering (including the gross proceeds from the exercise of the underwriter s over-allotment option) were approximately $353.3 million before giving effect to underwriting discounts and commissions and offering expenses. In connection with the Offering, the Partnership paid approximately $24.7 million in underwriting fees and incurred approximately $4.4 million of other offering costs. Approximately $5.7 million of the underwriting fee was paid to an affiliate of GS, which was acting as a joint book-running manager for the Offering. Until completion of CVR s February 2011 secondary offering, an affiliate of GS was a stockholder and related party of the Company. As a result of the Offering and as of the date of this Report, CVR indirectly owns 69.8% of the Partnership s outstanding common units and 100% of the Partnership s general partner, CVR GP, LLC, which only holds a non-economic interest.

In connection with the Offering, the Partnership s limited partner interests were converted into common units, the Partnership s special general partner interests were converted into common units, and the Partnership s special general partner was merged with and into CRLLC, with CRLLC continuing as the surviving entity. In addition, as discussed above, the managing general partner sold its IDRs to the Partnership for $26.0 million, these interests were extinguished, and CALLC III sold the managing general partner to CRLLC for a nominal amount. As a result of the Offering, the Partnership has two types of partnership interests outstanding:

- common units representing limited partner interests; and

- a general partner interest, which is not entitled to any distributions, and which is held by the Partnership s general partner.

The proceeds from the Offering were utilized as follows:

- approximately $18.4 million was distributed to CRLLC to satisfy the Partnership s obligation to reimburse it for certain capital expenditures made on behalf of the nitrogen fertilizer business prior to October 24, 2007;

- approximately $117.1 million was distributed to CRLLC through a special distribution in order to, among other things, fund the offer to purchase CRLLC s senior secured notes required upon the consummation of the Offering;

- $26.0 million was used by the Partnership to purchase and extinguish the IDR s owned by the general partner;

- approximately $4.8 million was used to pay financing fees and associated legal and professional fees resulting from the Partnership s new credit facility; and

- the balance of the proceeds are being utilized by the Partnership for general partnership purposes, including the funding of the UAN expansion that is expected to require an investment of approximately $135.0 million, of which approximately $31.0 million had been spent as of the Offering date.

The Partnership intends to make quarterly cash distributions of all available cash generated each quarter beginning with the quarter ended June 30, 2011, covering the period from the closing of the Offering through June 30, 2011 to common unitholders. The available cash for each quarter will be determined by the board of directors of the Partnership s general partner. The partnership agreement does not require that the Partnership

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CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

make cash distributions on a quarterly or other basis. In connection with the Offering, the board of directors of the general partner adopted a distribution policy, which it may change at any time.

The Partnership is operated by CVR s senior management (together with other officers of the general partner) pursuant to a services agreement among CVR, the general partner and the Partnership. The Partnership s general partner, CVR GP, LLC, manages the operations and activities of the Partnership, subject to the terms and conditions specified in the partnership agreement. The operations of the general partner in its capacity as general partner are managed by its board of directors. Actions by the general partner that are made in its individual capacity will be made by CRLLC as the sole member of the general partner and not by the board of directors of the general partner. The general partner is not elected by the common unitholders and is not subject to re-election on a regular basis. The officers of the general partner manage the day-to-day affairs of the business of the Partnership. CVR, the Partnership, their respective subsidiaries and the general partner are parties to a number of agreements to regulate certain business relations between them. Certain of these agreements were amended in connection with the Offering.

Basis of Consolidation

Prior to the Offering of the Partnership, management had determined that the Partnership was a variable interest entity (VIE) and as such evaluated the qualitative criteria under Accounting Standards Codification (ASC) Topic 810-10 *Consolidations-Variable Interest Entities* (ASC 810-10), to make a determination whether CVR Partners should be consolidated on the Company s financial statements. ASC 810-10 requires the primary beneficiary of a variable interest entity s activities to consolidate the VIE. The primary beneficiary is identified as the enterprise that has a) the power to direct the activities of the VIE that most significantly impact the entity s economic performance and b) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. The standard requires an ongoing analysis to determine whether the variable interest gives rise to a controlling financial interest in the VIE.

Subsequent to the Offering of the Partnership, the Partnership is no longer considered a VIE. The consolidation of the Partnership is based upon the fact that the general partner is owned by CRLLC, a wholly-owned subsidiary of CVR; and, therefore, CVR has the ability to control the activities of the Partnership. Additionally, the Partnership s general partner manages the operations and activities of the Partnership, subject to the terms and conditions specified in the partnership agreement. The operations of the general partner in its capacity as general partner are managed by its board of directors. Actions by the general partner that are made in its individual capacity will be made by CRLLC as the sole member of the general partner and not by the board of directors of the general partner. The general partner is not elected by the common unitholders of the Partnership and is not subject to re-election on a regular basis. The officers of the general partner manage the day-to-day affairs of the business. All but one of the officers of the general partner are also officers of CVR. Based upon the general partnership s role and rights as afforded by the partnership agreement and the limited rights afforded to the limited partners the consolidated financial statements of CVR will include the assets, liabilities, cash flows, revenues and expenses of the Partnership.

The limited rights of the common unitholders of the Partnership are demonstrated by the fact that the common unitholders have no right to elect the general partner or the general partner s directors on an annual or other continuing basis. The general partner can only be removed by a vote of the holders of at least 662/3% of the outstanding common units, including any common units owned by the general partner and its affiliates (including CRLLC, a wholly-owned subsidiary of CVR) voting together as a single class.

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

CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the Securities and Exchange Commission (SEC). The condensed 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, 2010 audited consolidated financial statements and notes thereto included in CVR s Annual Report on Form 10-K for the year ended December 31, 2010, which was filed with the SEC on March 7, 2011.

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, 2011 and December 31, 2010, the results of operations of the Company for the three and six months ended June 30, 2011 and 2010, and cash flows for the six months ended June 30, 2011 and 2010.

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, 2011 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, if any, that would require an adjustment or would require disclosure to the Company s condensed consolidated financial statements through the date of issuance of these condensed consolidated financial statements.

(2) Recent Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, *Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,* (ASU 2011-04). ASU 2011-04 changes the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements to ensure consistency between U.S. GAAP and International Financial Reporting Standards (IFRS). ASU 2011-04 also expands the disclosures for fair value measurements that are estimated using significant unobservable (Level 3) inputs. This new guidance is to be applied prospectively. ASU 2011-04 will be effective for interim and annual periods beginning after December 15, 2011, with early adoption permitted. The Company believes that the adoption of this standard will not materially expand its consolidated financial statement footnote disclosures.

In June 2011, the FASB issued ASU No. 2011-05, *Comprehensive Income (ASC Topic 220): Presentation of Comprehensive Income*, (ASU 2011-05) which amends current comprehensive income guidance. This ASU eliminates the option to present the components of other comprehensive income as part of the statement of shareholders equity. Instead, the Company must report comprehensive income in either a single continuous statement of comprehensive income which contains two sections, net income and other comprehensive income, or in two separate but consecutive statements. ASU 2011-05 will be effective for interim and annual periods beginning after December 15, 2011, with early adoption permitted. The adoption of ASU 2011-05 will not have a material impact on the Company s consolidated financial statements.

(3) Share-Based Compensation

Prior to CVR s initial public offering in October 2007, CVR s subsidiaries were held and operated by Coffeyville Acquisition LLC (CALLC) and its subsidiaries. Management of CVR held an equity interest in

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 in October 2007, CALLC was split into two entities: CALLC and Coffeyville Acquisition II LLC (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.

The fair value of the CALLC III override units for the three months ended June 30, 2011 was derived based upon the value, resulting from the proceeds received by the general partner upon the purchase of the IDR s by the Partnership. These proceeds were subsequently distributed to the owners of CALLC III which includes the override unitholders. This value was utilized to determine the related compensation expense for the unvested units. For the three and six months ended June 30, 2010, the estimated fair value of the override units of CALLC III were determined using a probability-weighted expected return method which utilized CALLC III s cash flow projections, which were considered representative of the nature of interests held by CALLC III in the Partnership.

In February 2011, CALLC and CALLC II sold into the public market 11,759,023 shares and 15,113,254 shares, respectively, of CVR s common stock, pursuant to a registered public offering. As a result of this offering, CALLC reduced its beneficial ownership in the Company to approximately 9% of its outstanding shares and CALLC II was no longer a stockholder of the Company. Subsequent to CALLC II s divestiture of its ownership interest in the Company, no additional share-based compensation expense was incurred with respect to override units and phantom units associated with CALLC II.

In May 2011, CALLC sold into the public market 7,998,179 shares of CVR s common stock, pursuant to a registered public offering. As a result, CALLC is no longer a stockholder of the Company. Subsequent to CALLC s divestiture of its ownership interest in the Company, no additional share-based compensation expense will be incurred with respect to override units and phantom units associated with CALLC.

The fair value of the override units of CALLC was derived based upon the value resulting from the proceeds received associated with CALLC s divestiture of its ownership in CVR. This value was utilized to determine the related compensation expense for the unvested units. The probability-weighted expected return method was also used to determine the estimated fair value of the override units of CALLC and CALLC II for the three and six months ended June 30, 2010. 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

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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 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, 2011	2010	Compensation Expense Increase (Decrease) for the Six Months Ended June 30, 2011	2010
Override Operating Units(a)	$ 11.31	919,630	June 2005	$	$ (78)	$	$ 338
Override Operating Units(b)	$ 34.72	72,492	December 2006		(2)		13
Override Value Units(c)	$ 11.31	1,839,265	June 2005	(27)	(1,184)	4,960	1,997
Override Value Units(d)	$ 34.72	144,966	December 2006	(64)	(13)	451	80
Override Units(e)	$ 10.00	138,281	October 2007				
Override Units(f)	$ 10.00	642,219	February 2008	49	1	184	3
			Total	$ (42)	$ (1,276)	$ 5,595	$ 2,431

Due to the divestiture of all ownership in CVR by CALLC and CALLC II and due to the purchase of IDRs from the general partner and the distribution to CALLC III, there is no associated unrecognized compensation expense as of June 30, 2011.

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, 2010	(b) Override Operating Units June 30, 2010
Estimated forfeiture rate	None	None
CVR closing stock price	$ 7.52	$ 7.52
Estimated weighted-average fair value (per unit)	$ 13.02	$ 2.06

Marketability and minority interest discounts	20.0%	20.0%
Volatility	54.5%	54.5%

As of June 30, 2010, all of the recipients of the override operating units 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, 2010	**(d) Override Value Units June 30, 2010**
Estimated forfeiture rate	None	None
Derived service period	6 years	6 years
CVR closing stock price	$ 7.52	$ 7.52
Estimated weighted-average fair value (per unit)	$ 7.12	$ 2.05
Marketability and minority interest discounts	20.0%	20.0%
Volatility	54.5%	54.5%

(e) *Override Units* Using a binomial and a probability-weighted expected return method which utilized CALLC III s cash flow projections and included expected future earnings and the anticipated timing of IDRs,

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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 had 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, 2011 these units were fully vested.

(f) *Override Units* Using a probability-weighted expected return method which utilized CALLC III s cash flow projections and included 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 had 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
Estimated forfeiture rate	None
Derived Service Period	Based on forfeiture schedule
Estimated fair value (per unit)	$0.08
Marketability and minority interest discount	20.0%
Volatility	59.7%

Phantom Unit Appreciation 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 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 plans expire on July 25, 2015, or at the discretion of CVR.

The expense associated with these awards is based on the current fair value of the awards which historically has been 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.

CVR has recorded approximately $0 and approximately $18.7 million in personnel accruals as of June 30, 2011 and December 31, 2010, respectively. Compensation expense for the three months ended June 30, 2011 related to the Phantom Unit Plans was reversed by approximately $0.7 million. Compensation expense for the three months ended June 30, 2010 related to the Phantom Unit Plans was reversed by approximately $1.8 million. Compensation expense for the six months ended June 30, 2011 and 2010 related to the Phantom Unit Plans was approximately $10.6 million and $1.6 million, respectively.

As described above, in February 2011, CALLC and CALLC II completed a sale of CVR common stock into the public market pursuant to a registered public offering. As a result of this offering, the Company made a payment to phantom unitholders of approximately $20.1 million in the first quarter of 2011. As described above, in May 2011, CALLC completed an additional sale of CVR common stock into the public market pursuant to a registered public offering. As a result of this offering, the Company made a payment to phantom unitholders of approximately $9.2 million in the second quarter of 2011.

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Due to the divestiture of all ownership of CVR by CALLC and CALLC II and the associated payments to the holders of service and phantom performance points, there is no unrecognized compensation expense at June 30, 2011.

Using the Company s closing stock price at June 30, 2010, to determine the Company s equity value, through an independent valuation process, the service phantom interest and performance phantom interest were valued as follows:

	June 30, 2010
Service Phantom interest (per point)	$ 12.46
Performance Phantom interest (per point)	$ 6.96

Long-Term Incentive Plan

CVR has a Long-Term Incentive Plan (LTIP) which permits the grant of options, stock appreciation rights, restricted shares, restricted share units, dividend equivalent rights, share awards and performance awards (including performance share units, performance units and performance-based restricted stock). As of June 30, 2011, only restricted shares of CVR common stock and stock options had been granted under the LTIP. Individuals who are eligible to receive awards and grants under the LTIP include the Company s employees, officers, consultants, advisors and directors.

Stock Options

As of June 30, 2011, there have been a total of 32,350 stock options granted, of which 26,168 have vested. However, 6,301 vested options have expired resulting in a net total of 19,867 outstanding options that have vested. Additionally, 3,149 unvested stock options were forfeited in the second quarter of 2010. There were 1,450 options that vested in the second quarter of 2011. There were no options forfeited or granted in the second quarter of 2011. The fair value of stock options is estimated on the date of grant using the Black-Scholes option pricing model. As of June 30, 2011, there was approximately $1,600 of total unrecognized compensation cost related to stock options which will be fully recognized in the third quarter of 2011 upon vesting.

Restricted Stock

A summary of restricted stock grant activity and changes during the six months ended June 30, 2011 is presented below:

Restricted Stock	Shares	Weighted-Average Grant-Date Fair Value
Outstanding at January 1, 2011 (non-vested)	1,369,182	$ 10.94
Vested	(21,854)	15.25
Granted	13,521	19.97

Forfeited	(3,066)		5.94
Outstanding at June 30, 2011 (non-vested)	1,357,783	$	10.97

Through the LTIP, restricted shares have been granted to employees of the Company. Restricted 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, 2011, there was approximately $8.9 million of total

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

unrecognized compensation cost related to restricted shares to be recognized over a weighted-average period of approximately two years.

Compensation expense recorded for the three months ended June 30, 2011 and 2010 related to the restricted shares and stock options was approximately $2.5 million and $0.2 million, respectively. Compensation expense recorded for the six months ended June 30, 2011 and 2010 related to the restricted shares and stock options was approximately $4.7 million and $0.4 million, respectively.

CVR Partners Long-Term Incentive Plan

In connection with the Offering, the board of directors of the general partner adopted the CVR Partners, LP Long-Term Incentive Plan (CVR Partners LTIP). Individuals who are eligible to receive awards under the CVR Partners LTIP include CVR Partners , its subsidiaries and its parent s employees, officers, consultants and directors. The CVR Partners LTIP provides for the grant of options, unit appreciation rights, distribution equivalent rights, restricted units, phantom units and other unit-based awards, each in respect of common units. The maximum number of common units issuable under the CVR Partners LTIP is 5,000,000.

In connection with the Offering, 23,448 phantom units were granted to certain board members of the Partnership s general partner. These phantom units are expected to vest six months following the grant date. These phantom unit awards granted to the directors of the general partner are considered non-employee equity-based awards since the directors are not elected by unitholders. These phantom unit director awards are required to be marked-to-market each reporting period until they are vested.

In June 2011, 50,659 phantom units were granted to an employee of the general partner. These phantom units are expected to vest over three years on the basis of one-third of the award each year. As this phantom award, which is an equity-based award, was granted to an employee of a subsidiary of the Company, it was valued at the closing unit price of the Partnership s common units on the date of grant and will be amortized to compensation expense on a straight-line basis over the vesting period of the award.

In June 2011, 2,956 fully vested common units were granted to certain board members of the general partner. The fair value of these awards was calculated using the closing price of the Partnership s common units on the date of grant. This amount was fully expensed at the time of grant.

Compensation expense recorded for the three months ended June 30, 2011 and 2010, related to the awards under the CVR Partners LTIP was approximately $0.3 million and $0, respectively. Compensation expense recorded for the six months ended June 30, 2011 and 2010, related to the awards under the CVR Partners LTIP was approximately $0.3 million and $0, respectively. Compensation expense associated with the awards under the CVR Partners LTIP has been recorded in selling, general and administrative expenses (exclusive of depreciation and amortization).

As of June 30, 2011, there were 4,922,937 common units available for issuance under the CVR Partners LTIP. Unrecognized compensation expense associated with the unvested phantom units at June 30, 2011 was approximately $1.2 million.

(4) Inventories

Inventories consist primarily of domestic and foreign 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

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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:

	June 30, 2011	December 31, 2010
	(in thousands)	
Finished goods	$ 129,881	$ 110,788
Raw materials and precious metals	135,619	89,333
In-process inventories	24,473	22,931
Parts and supplies	25,973	24,120
	$ 315,946	$ 247,172

(5) Property, Plant, and Equipment

A summary of costs for property, plant, and equipment is as follows:

	June 30, 2011	December 31, 2010
	(in thousands)	
Land and improvements	$ 19,819	$ 19,228
Buildings	27,087	25,663
Machinery and equipment	1,366,202	1,363,877
Automotive equipment	11,396	8,747
Furniture and fixtures	9,703	9,279
Leasehold improvements	1,361	1,253
Construction in progress	59,260	42,674
	1,494,828	1,470,721
Accumulated depreciation	(433,486)	(389,409)
	$ 1,061,342	$ 1,081,312

Capitalized interest recognized as a reduction in interest expense for the three months ended June 30, 2011 and 2010 totaled approximately $0.8 million in both periods. Capitalized interest recognized as a reduction in interest expense for the six months ended June 30, 2011 and 2010, totaled approximately $0.9 million and $1.6 million, respectively. Buildings and equipment that are under a capital lease obligation approximated $0.3 million as of June 30, 2011.

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 approximately $0.6 million and $0.7 million for the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, cost of product sold excludes depreciation and amortization of approximately $1.3 million and $1.5 million, respectively.

Direct operating expenses (exclusive of depreciation and amortization) includes direct costs of labor, maintenance and services, energy and utility costs, property taxes, as well as chemicals and catalysts and other direct operating expenses. Direct operating expenses exclude depreciation and amortization of approximately

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$20.9 million and $20.3 million for the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, direct operating expenses exclude depreciation and amortization of approximately $41.8 million and $40.3 million, respectively.

Selling, general and administrative expenses (exclusive of depreciation and amortization) consist primarily of legal, treasury, accounting, marketing, human resources and costs associated with maintaining the corporate and administrative office in Texas and the administrative office in Kansas. Selling, general and administrative expenses exclude depreciation and amortization of approximately $0.5 million for both of the three months ended June 30, 2011 and 2010. For the six months ended June 30, 2011 and 2010, selling, general and administrative expenses exclude depreciation and amortization of approximately $1.0 million and $1.0 million, respectively.

(7) Note Payable and Capital Lease Obligations

The Company entered into an insurance premium finance agreement in July 2010 to finance a portion of the purchase of its 2010/2011 property insurance policies. The original balance of the note provided by the Company under such agreement was approximately $5.0 million. The Company began to repay this note in equal installments commencing October 1, 2010. As of June 30, 2011 and December 31, 2010, the Company owed $0 and approximately $3.1 million, respectively, related to this note.

From time to time, the Company enters lease agreements for purposes of acquiring assets used in the normal course of business. The majority of the Company s leases are accounted for as operating leases. During 2010, the Company entered two lease agreements for information technology equipment that are accounted for as capital leases. The initial capital lease obligation of these agreements totaled approximately $0.4 million. The two capital leases entered into during 2010 have terms of 12 and 36 months. As of June 30, 2011, the outstanding capital lease obligation associated with these leases totaled $0.2 million.

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. The Company was obligated to make quarterly lease payments that totaled approximately $0.1 million annually. The Company also had the option to purchase the property during the term of the lease, including the renewal periods. The capital lease obligation was approximately $4.6 million as of December 31, 2010. In March 2011, the Company exercised its purchase option and paid approximately $4.7 million to satisfy the lease obligation.

(8) Insurance Claims

Nitrogen Fertilizer Incident

On September 30, 2010, the nitrogen fertilizer plant experienced an interruption in operations due to a rupture of a high-pressure UAN vessel. All operations at the nitrogen fertilizer facility were immediately shut down. No one was injured in the incident. Repairs to the facility as a result of the rupture were substantially complete as of December 31, 2010.

Total gross costs recorded as of June 30, 2011 due to the incident were approximately $11.1 million for repairs and maintenance and other associated costs. Approximately $0.2 million of these costs was recognized during the three months ended June 30, 2011. Approximately $0.6 million of these costs was recognized during the six months ended June 30, 2011. The repairs and maintenance costs incurred are included in direct operating expenses (exclusive of depreciation and amortization). Of the costs incurred approximately $4.5 million was capitalized.

The Company maintains property damage insurance policies which have an associated deductible of $2.5 million. The Company anticipates that substantially all of the repair costs in excess of the $2.5 million

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deductible should be covered by insurance. These insurance policies also provide coverage for interruption to the business, including lost profits, and reimbursement for other expenses and costs the Company has incurred relating to the damage and losses suffered for business interruption. This coverage, however, only applies to losses incurred after a business interruption of 45 days. In connection with the incident, the Company recorded an insurance receivable of approximately $4.5 million, of which approximately $4.3 million of insurance proceeds was received in December 2010 and the remaining approximately $0.2 million was received in January 2011. The recording of the insurance receivable resulted in a reduction of direct operating expenses (exclusive of depreciation and amortization).

In the first quarter of 2011, the Company submitted a partial business interruption claim for damages and losses, as afforded by its insurance policies. The Company s insurance carriers agreed to make interim payments totaling approximately $2.9 million. Insurance proceeds were received totaling approximately $2.3 million related to the business interruption claim through March 31, 2011 and the Company received the remaining approximate $0.6 million in April 2011. The proceeds associated with the business interruption claim are included on the Condensed Consolidated Statements of Operations under Insurance recovery business interruption.

Refinery Incidents

On December 28, 2010 the crude oil refinery experienced an equipment malfunction and small fire in connection with its fluid catalytic cracking unit (FCCU), which led to reduced crude throughput. The refinery returned to full operations on January 26, 2011. This interruption adversely impacted the production of refined products for the petroleum business in the first quarter of 2011. Total gross repair and other costs recorded related to the incident as of June 30, 2011 were approximately $8.1 million. No costs were recorded during the three months ended June 30, 2011. As documented above, the Company maintains property damage insurance policies which have an associated deductible of $2.5 million. The Company anticipates that substantially all of the costs in excess of the deductible should be covered by insurance. As of June 30, 2011, the Company has recorded an insurance receivable related to the incident of approximately $5.2 million. The insurance receivable is included in other current assets in the Condensed Consolidated Balance Sheet. The recording of the insurance receivable resulted in a reduction of direct operating expenses (exclusive of depreciation and amortization).

The crude oil refinery experienced a small fire at its continuous catalytic reformer (CCR) in May 2011. Total gross repair and other costs recorded related to the incident for the three months ended June 30, 2011 approximated $3.1 million. The Company anticipates that substantially all of the costs in excess of the $2.5 million deductible should be covered by insurance under its property damage insurance policy. As of June 30, 2011, the Company has recorded an insurance receivable of approximately $0.6 million. The insurance receivable is included in other current assets in the Condensed Consolidated Balance Sheet. The recording of the insurance receivable resulted in a reduction of direct operating expenses (exclusive of depreciation and amortization).

(9) Income Taxes

The Company recognizes liabilities, interest and penalties for potential tax issues based on its estimate of whether, and the extent to which, additional taxes may be due as determined under ASC Topic 740 *Income Taxes*. In the second quarter of 2011, the Company recorded approximately $17.5 million associated with uncertain tax positions. As of June 30, 2011, the Company had unrecognized tax benefits of approximately $0.2 million which, if recognized, would impact the Company s effective tax rate. Unrecognized tax benefits that are not expected to be settled within the next twelve months are included in other long-term liabilities in the condensed consolidated balance sheet; unrecognized tax benefits that are expected to be settled within the next twelve months are included in income taxes payable. The Company has not accrued any amounts for

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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. At June 30, 2011, the Company s tax filings are generally open to examination in the United States for the tax years ended December 31, 2008 through December 31, 2010 and in various individual states for the tax years ended December 31, 2007 through December 31, 2010.

The Company s effective tax rate for the three and six months ended June 30, 2011 was 36.38% and 36.59%, 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, 2011 is lower than the statutory rate primarily due to the reduction of income subject to tax associated with the noncontrolling ownership interest of CVR Partners, LP s earnings beginning April 13, 2011, as well as benefits for domestic production activities. The Company s effective tax rate for the three and six months ended June 30, 2010 was (58.5%) and 42%, respectively. The Company s 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 effected interest income with the pre-tax income and loss levels increased the effected tax rate of the tax benefit recorded for the periods in 2010.

(10) Earnings Per Share

Basic and diluted earnings per share are computed by dividing net income (loss) attributable to CVR Energy stockholders 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,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands, except share data)			
Net income (loss) attributable to CVR Energy stockholders	$ 124,865	$ 1,152	$ 170,653	$ (11,211)
Weighted-average common shares outstanding	86,422,881	86,336,125	86,418,356	86,332,700
Effect of dilutive securities:				
Non-vested common stock	1,362,167	170,465	1,364,131	
Stock options	4,303		3,801	
Weighted-average common shares outstanding assuming dilution	87,789,351	86,506,590	87,786,288	86,332,700
Basic earnings (loss) per share	$ 1.44	$ 0.01	$ 1.97	$ (0.13)
Diluted earnings (loss) per share	$ 1.42	$ 0.01	$ 1.94	$ (0.13)

Outstanding stock options totaling 19,099 and 29,201 common shares were excluded from the diluted earnings per share calculation for the six months ended June 30, 2011 and 2010, respectively, as they were antidilutive. Outstanding stock options totaling 18,597 and 29,201 common shares were excluded from the diluted earnings per share calculation for the three months ended June 30, 2011 and 2010, respectively, as they were antidilutive. For the six months ended June 30, 2010, 173,715 shares of restricted common stock were excluded from the diluted earnings (loss) per share calculation, as they were antidilutive.

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(11) Commitments and Contingencies

Leases and Unconditional Purchase Obligations

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

	Operating Leases	Unconditional Purchase Obligations(1)
	(in thousands)	
Six months ending December 31, 2011	$ 3,462	$ 45,142
Year ending December 31, 2012	7,172	87,560
Year ending December 31, 2013	5,433	87,632
Year ending December 31, 2014	3,234	87,712
Year ending December 31, 2015	1,849	82,018
Thereafter	1,298	414,402
	$ 22,448	$ 804,466

(1) This amount includes approximately $529.4 million payable ratably over ten years pursuant to petroleum transportation service agreements between CRRM and TransCanada Keystone Pipeline, LP (TransCanada). Under the agreements, Coffeyville Resources Refining and Marketing (CRRM) receives 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 TransCanada s Keystone pipeline system. On September 15, 2009, the Company filed a Statement of Claim in the Court of the Queen s Bench of Alberta, Judicial District of Calgary, to dispute the validity of the petroleum transportation service agreements. The Company and TransCanada settled this claim in March 2011. CRRM began receiving crude oil under the agreements on the terms discussed above in the first quarter of 2011.

The Company leases various equipment, including rail cars, and real properties under long-term operating leases, expiring at various dates. For the three months ended June 30, 2011 and 2010, lease expense totaled approximately $1.3 million and $1.4 million, respectively. For the six months ended June 30, 2011 and 2010, lease expense totaled approximately $2.6 million and $2.6 million, 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, storage, utilities 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. These provisions are reviewed at least quarterly and adjusted to reflect the impacts of negotiations, settlements, rulings, advice of legal counsel, and other information and events pertaining to a particular case. 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.

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 state court in Oklahoma and Kansas. All of the lawsuits filed in state court were removed to federal court. All of the lawsuits (except for the New Mexico suits, which remained in federal court in New Mexico) were then transferred to the Bankruptcy Court for the United States District Court for the District of Delaware, where the Sem Group bankruptcy resides. In March 2011, CRRM was dismissed without prejudice from the New Mexico suits. All of the lawsuits allege that Samson or 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 Samson 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 is 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. On January 26, 2011, CRRM and J. Aron entered into an agreement whereby J. Aron agreed to indemnify and defend CRRM from any damage, out-of-pocket expense or loss in connection with any crude oil involved in the lawsuits which CRRM purchased through J. Aron, and J. Aron agreed to reimburse CRRM s prior attorney fees and out-of-pocket expenses in connection with the lawsuits.

CRNF received a ten year property tax abatement from Montgomery County, Kansas in connection with its construction that expired on December 31, 2007. In connection with the expiration of the abatement, the county reassessed CRNF s nitrogen fertilizer plant and classified the nitrogen fertilizer plant as almost entirely real property instead of almost entirely personal property. The reassessment has resulted in an increase to annual property tax expense for CRNF by an average of approximately $11.7 million per year for the year ended December 31, 2010, and approximately $10.7 million for the years ended December 31, 2009 and 2008, respectively. CRNF does not agree with the county s classification of the nitrogen fertilizer plant and CRNF is currently disputing it before the Kansas Court of Tax Appeals (COTA). However, CRNF has fully accrued and paid the property taxes the county claims are owed for the years ended December 31, 2010, 2009 and 2008 and has estimated and accrued for property taxes for the first six months of 2011. These amounts are reflected as a direct operating expense in the Condensed Consolidated Statements of Operations. An evidentiary hearing before COTA occurred during the first quarter of 2011 regarding the property tax claims for the year ended December 31, 2008. CRNF believes it is possible that COTA may issue a ruling sometime during 2011. However, the timing of a ruling in the case is uncertain, and there can be no assurance CRNF will receive a ruling in 2011. If CRNF is successful in having the nitrogen fertilizer plant reclassified as personal property, in whole or in part, a portion of the accrued and paid expenses would be refunded to CRNF, which could have a material positive effect on CRNF s and the Company s results of operations. If CRNF is not successful in having the nitrogen fertilizer plant reclassified as personal property, in whole or in part, CRNF expects that it will continue to pay property taxes at elevated rates.

On July 25, 2011, Mid-America Pipeline Company, LLC (MAPL) filed an application with the Kansas Corporation Commission (KCC) for the purpose of establishing rates (New Rates) effective October 1, 2011 for pipeline transportation service on MAPL s liquids pipelines running between Conway, Kansas and Coffeyville, Kansas (Inbound Line) and between Coffeyville, Kansas and El Dorado, Kansas (Outbound Line). CRRM currently ships refined fuels on the Outbound Line pursuant to transportation rates established by a pipeline capacity lease with MAPL which expires September 30, 2011 and CRRM currently ships natural gas liquids on the Inbound Line pursuant to a pipeage contract which also expires September 30, 2011. Although CRRM intends to vigorously contest the New Rates at the KCC, if MAPL is successful in obtaining

CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the entirety of its proposed rate increase, under CRRM s historic pipeline usage patterns, the New Rates would result in a total annual increase of approximately $14.75 million for CRRM s use of the Inbound and the Outbound Lines.

See note (1) to the table at the beginning of this Note 11 (Commitments and Contingencies) 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 the 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 $4.4 million (plus punitive damages). In August 2008, those claimants filed suit against the Company in the United States District Court for the District of Kansas in Wichita (the 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 $3.2 million (plus punitive damages) for three additional plaintiffs as a result of the July 1, 2007 crude oil discharge. In August 2010, the Company settled claims with eight of the plaintiffs from the Angleton Case, and in May and June 2011, the Company settled six more claims in the Angleton and companion case. The settlements did not have a material adverse effect on the consolidated financial statements. The Company believes that the resolution of the remaining 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 United States Environmental Protection Agency (EPA) on July 10, 2007. As set forth in the Consent Order, the EPA concluded that the discharge of crude oil from the Company s refinery caused an imminent and substantial threat to the public health and welfare. Pursuant to the Consent Order, the Company agreed to perform specified remedial actions to respond to the discharge of crude oil from the Company s refinery. The substantial majority of all required remedial actions were completed by January 31, 2009. The Company prepared and provided its final report to the EPA in January 2011 to satisfy the final requirement of the Consent Order. In April 2011, the EPA provided the Company with a notice of completion indicating that the Company has no continuing obligations under the Consent Order, while reserving its rights to recover oversight costs and penalties.

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. On October 25, 2010, the Company received a letter from the United States Coast Guard on behalf of the EPA claiming approximately $1.8 million in oversight cost reimbursement. The Company has responded by asserting defenses to the Coast Guard s claim for oversight costs. The EPA has indicated that it intends to seek to recover a civil penalty related to the oil spill, but no demand has been made. The Company intends to assert the same defenses to liability for any civil penalty that may be made.

The Company is seeking insurance coverage for this release and for the ultimate costs for remediation and third-party property damage claims. On July 10, 2008, the Company filed a lawsuit in the United States District Court for the District of Kansas against certain of the Company s environmental insurance carriers requesting insurance coverage indemnification for the June/July 2007 flood and crude oil discharge losses. Each insurer reserved its rights under various policy exclusions and limitations and cited potential coverage defenses. Although the Court has now issued summary judgment opinions that eliminate the majority of the insurance defendants reservations and defenses, 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 $25.0 million of insurance proceeds under its primary

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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.

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). As of June 30, 2011 and December 31, 2010, environmental accruals of $2.6 million and $4.1 million, respectively, were reflected in the Condensed Consolidated Balance Sheets for probable and estimated costs for remediation of environmental contamination under the RCRA Administrative Orders, for which approximately $0.9 million and approximately $1.5 million, respectively, are included in other current liabilities. The Company s accruals were determined based on an estimate of payment costs through 2031, for which the scope of remediation was arranged with the EPA, and were discounted at the appropriate risk free rates at June 30, 2011 and December 31, 2010, respectively. The accruals include estimated closure and post-closure costs of $0.9 million and approximately $0.9 million for two landfills at June 30, 2011 and December 31, 2010, respectively. The estimated future payments for these required obligations are as follows:

Year Ending December 31,	**Amount (in thousands)**
Six months ending December 31, 2011	$ 532
2012	642
2013	196
2014	196
2015	196
Thereafter	1,276
Undiscounted total	3,038

Less amounts representing interest at 2.69%		388
Accrued environmental liabilities at June 30, 2011	$	2,650

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.

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. Capital expenditures to comply with the rule are expected to be approximately $10.0 million.

CRRM is subject to the Renewable Fuel Standard (RFS) which requires refiners to blend renewable fuels in with their transportation fuels or purchase renewable energy credits in lieu of blending. The EPA is required to determine and publish the applicable annual renewable fuel percentage standards for each compliance year by November 30 for the previous year. The percentage standards represent the ratio of renewable fuel volume to gasoline and diesel volume. Thus, in 2011, about 8% of all fuel used will be renewable fuel. In 2012, the EPA has proposed to raise the renewable fuel percentage standards to about 9%. Due to mandates in the RFS 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 to the extent that these increased costs cannot be passed on to the consumers. CRRM s small refiner status under the original RFS expired on December 31, 2010. Beginning on January 1, 2011, CRRM was required to blend renewable fuels into its gasoline and diesel fuel or purchase renewable energy credits, known as Renewable Identification Numbers (RINs) in lieu of blending. For the three and six months ended June 30, 2011, CRRM incurred approximately $5.0 million and $8.5 million, respectively, of expense associated with the required mandate which was included in cost of product sold in the Condensed Consolidated Statements of Operations. To achieve compliance with the renewable fuel standard for the remainder of 2011, CRRM will blend renewable fuels into its refined products whenever possible and will also purchase RINs to bridge any shortfall created by a deficiency in renewable fuel blended production.

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 crude oil refinery and Phillipsburg terminal facilities. As a result of CRRM s 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 remaining costs of complying with the Consent Decree are expected to be approximately $49.0 million, of which approximately $47.0 million is expected to be capital expenditures which does not include the cleanup obligations for historic contamination at the site that are being addressed pursuant to administrative orders issued under 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 fifteen 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 agreed to offset any incremental emissions resulting from the delay by providing additional controls to existing emission sources over a set timeframe.

In the meantime, CRRM has been negotiating with the EPA and KDHE to replace the current Consent Decree, including the fifteen month extension, with a global settlement under the National Petroleum Refining Initiative. Over the course of the last decade, the EPA has embarked on a 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 refineries entering into consent decrees imposing civil penalties and requiring substantial expenditures for pollution control and enhanced operating procedures. The EPA has

CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

indicated that it will seek to have all refiners enter into global settlements pertaining to all marquee issues. The current Consent Decree covers some, but not all, of the marquee issues. The Company has been negotiating with the EPA to expand the existing Consent Decree obligations to include all of the marquee issues under the Petroleum Refining Initiative, and the parties have reached an agreement in principle on most of the issues, including an agreement to further extend the deadline for the installation of controls on the FCCU. Under the global settlement, the Company may be required to pay a civil penalty, but the incremental capital expenditures would not be material and would be limited primarily to the retrofit and replacement of heaters and boilers over a five to seven year timeframe.

On February 24, 2010, the Company received a letter from the United States Department of Justice on behalf of the EPA seeking an approximately $0.9 million civil penalty related to alleged late and incomplete reporting of air releases in violation of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and the Emergency Planning and Community Right-to-Know Act (EPCRA). The Company has reviewed and is contesting the EPA s allegation. CRRM has entered into a tolling agreement concerning EPA s claims. The tolling agreement in 2010 was amended to include the EPA s allegations related to CRRM s compliance with the Clean Air Act s Risk Management Program (RMP). EPA has investigated CRRM s operation for compliance with the RMP program, but has not made any claims against CRRM.

From time to time, the EPA has conducted inspections and issued information requests to CRNF with respect to the Company s compliance with the RMP and the release reporting requirements under CERCLA and the EPCRA. These previous investigations have resulted in the issuance of preliminary findings regarding CRNF s compliance status. In the fourth quarter of 2010, following CRNF s reported release of ammonia from its cooling water system and the rupture of its UAN vessel (which released ammonia and other regulated substances), the EPA conducted its most recent inspection and issued an additional request for information to CRNF. The EPA has not made any formal claims against the Company and the Company has not accrued for any liability associated with the investigations or releases.

Environmental expenditures are capitalized when such expenditures are expected to result in future economic benefits. For the three months ended June 30, 2011 and 2010, capital expenditures were approximately $0.9 million and $3.3 million, respectively. For the six months ended June 30, 2011 and 2010, capital expenditures were approximately $2.5 million and $11.0 million, respectively. These expenditures were incurred to improve the environmental compliance and efficiency of the 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.

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(12) Long-Term Debt

Long-term debt was as follows:

	June 30, 2011	December 31, 2010
	(in thousands)	
9.0% Senior Secured Notes, due 2015, net of unamortized discount of $958 and $1,065 as of June 30, 2011 and December 31, 2010, respectively	$ 246,092	$ 246,435
10.875% Senior Secured Notes, due 2017, net of unamortized discount of $2,307 and $2,481 as of June 30, 2011 and December 31, 2010, respectively	220,443	222,519
CRNF credit facility	125,000	
Long-term debt	$ 591,535	$ 468,954

Senior Secured Notes

On April 6, 2010, CRLLC and its wholly-owned subsidiary, Coffeyville Finance Inc. (together the Issuers), completed a private offering 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). 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. The associated original issue discount of the Notes is amortized to interest expense and other financing costs over the respective term of the Notes. On December 30, 2010, CRLLC made a voluntary unscheduled principal payment of $27.5 million on the First Lien Notes that resulted in a premium payment of 3.0% and a partial write-off of previously deferred financing costs and unamortized original issue discount. On May 16, 2011, CRLLC repurchased $2.7 million of the Notes at a purchase price of 103% of the outstanding principal amount, which resulted in a premium payment of 3.0% and a partial write-off of previously deferred financing costs and unamortized issue discount. At June 30, 2011, the estimated fair value of the First and Second Lien Notes was approximately $266.0 million and $250.0 million, 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, with the exception of the Partnership and CRNF. In connection with the closing of the Partnership s initial public offering in April 2011, the Partnership and CRNF were released from their guarantees of the 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.

Senior Notes Tender Offer

The completion of the initial public offering of the Partnership in April 2011 triggered a Fertilizer Business Event (as defined in the indentures governing the Notes). As a result, CRLLC and Coffeyville Finance Inc. were required to offer to purchase a portion of the Notes from holders at a purchase price equal to 103.0% of the principal amount plus accrued and unpaid interest. A Fertilizer Business Event Offer was made on April 14, 2011 to purchase up to $100.0 million of the First Lien Notes and the Second Lien Notes, as required by the indentures governing the Notes. Holders of the Notes had until May 16, 2011 to properly tender Notes they wished to have repurchased. Approximately $2.7 million of the Notes were repurchased, including approximately $0.5 million of First Lien Notes and $2.2 million of Second Lien Notes.

CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ABL Credit Facility

On February 22, 2011, CRLLC and certain other subsidiaries of CVR entered into a $250.0 million asset-backed revolving credit agreement (ABL credit facility) with a group of lenders including Deutsche Bank Trust Company Americas as collateral and administrative agent. The ABL credit facility, which is scheduled to mature in August 2015, replaced the $150.0 million first priority revolving credit facility which was terminated. The ABL credit facility will be used to finance ongoing working capital, capital expenditures, letter of credit issuances and general needs of the Company and includes, among other things, a letter of credit sublimit equal to 90% of the total facility commitment and an accordion feature which permits an increase in borrowings of up to $250.0 million (in the aggregate), subject to receipt of additional lender commitments. As of June 30, 2011, CRLLC had availability under the ABL credit facility of $218.4 million and had letters of credit outstanding of approximately $31.6 million. There were no borrowings outstanding under the ABL credit facility as of June 30, 2011.

Borrowings under the facility bear interest based on a pricing grid determined by the previous quarter s excess availability. The pricing for LIBOR loans under the ABL credit facility can range from LIBOR plus 2.75% to LIBOR plus 3.0%, for base rate loans, the prime rate plus 1.75% to prime rate plus 2.0%. Availability under the ABL credit facility is determined by a borrowing base formula supported primarily by cash and cash equivalents, certain accounts receivable and inventory.

The ABL credit facility contains customary covenants for a financing of this type that limit, subject to certain exceptions, the incurrence of additional indebtedness, the creation of liens on assets, the ability to dispose of assets, the ability to make restricted payments, investments or acquisitions, sale-leaseback transactions and affiliate transactions. The ABL credit facility also contains a fixed charge coverage ratio financial covenant that is triggered when borrowing base excess availability is less than certain thresholds, as defined under the facility. As of June 30, 2011, CRLLC was in compliance with the covenants of the ABL credit facility.

In connection with the ABL credit facility, through June 30, 2011, CRLLC has incurred lender and other third party costs of approximately $5.9 million. These costs were deferred and are being amortized to interest expense and other financing costs using a straight-line method over the term of the facility. In connection with termination of the first priority credit facility, a portion of the unamortized deferred financing costs associated with the facility, totaling approximately $1.9 million, was written off in the first quarter of 2011. In accordance with guidance provided by the FASB regarding the modification of revolving debt arrangements, the remaining approximately $0.8 million of unamortized deferred financing costs associated with the first priority credit facility will continue to be amortized over the term of the ABL credit facility.

Included in other current liabilities on the Condensed Consolidated Balance Sheets is accrued interest payable totaling approximately $12.9 million and $12.2 million as of June 30, 2011 and December 31, 2010, respectively. As of June 30, 2011, of the accrued interest payable, approximately $11.6 million is related to the Notes. As of December 31, 2010, of the accrued interest payable, approximately $11.8 million is related to the Notes and the first priority credit facility borrowing arrangement.

In connection with the closing of the Partnership s initial public offering in April 2011, the Partnership and CRNF were released as guarantors of the ABL credit facility.

CRNF Credit Facility

On April 13, 2011, CRNF, as borrower, and the Partnership, as guarantor, entered into a new credit facility with a group of lenders including Goldman Sachs Lending Partners LLC, as administrative and collateral agent. The credit facility includes a term loan facility of $125.0 million and a revolving credit facility of $25.0 million with an uncommitted incremental facility of up to $50.0 million. No amounts were outstanding under the revolving credit facility at June 30, 2011. There is no scheduled amortization of the credit facility with it being due and payable in full at its April 2016 maturity. The Partnership, upon the

CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

closing of the credit facility, made a special distribution of approximately $87.2 million to CRLLC, in order to, among other things, fund the offer to purchase CRLLC s senior secured notes required upon consummation of the Offering. The credit facility will be used to finance on-going working capital, capital expenditures, letters of credit issuances and general needs of CRNF.

Borrowings under the credit facility bear interest based on a pricing grid determined by the trailing four quarter leverage ratio. The initial pricing for Eurodollar rate loans under the credit facility is the Eurodollar rate plus a margin of 3.75% or, for base rate loans, the prime rate plus 2.75%. Under its terms, the lenders under the credit facility were granted a perfected, first priority security interest (subject to certain customary exceptions) in substantially all of the assets of CRNF and the Partnership.

The credit facility requires CRNF to maintain a minimum interest coverage ratio and a maximum leverage ratio and contains customary covenants for a financing of this type that limit, subject to certain exceptions, the incurrence of additional indebtedness or guarantees, the creation of liens on assets, the ability to dispose of assets, the ability to make restricted payments, investments and acquisitions, sale-leaseback transactions and affiliate transactions. The credit facility provides that the Partnership can make distributions to holders of its common units provided, among other things, it is in compliance with the leverage ratio and interest coverage ratio on a pro forma basis after giving effect to any distribution and there is no default or event of default under the credit facility. As of June 30, 2011, CRNF was in compliance with the covenants of the credit facility.

In connection with the credit facility, through June 30, 2011, CRNF has incurred lender and other third party costs of approximately $4.9 million. The costs associated with the credit facility have been deferred and are being amortized over the term of the credit facility as interest expense using the effective-interest amortization method for the term loan facility and the straight-line method for the revolving credit facility.

(13) Fair Value Measurements

In accordance with ASC Topic 820 *Fair Value Measurements and Disclosures* (ASC 820), the Company utilizes the market approach to measure fair value for its financial assets and liabilities. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

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)

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the assets and liabilities measured at fair value on a recurring basis, by input level, as of June 30, 2011 and December 31, 2010:

	June 30, 2011 (in thousands)			
	Level 1	Level 2	Level 3	Total
Location and Description				
Cash equivalents (money market account)	$ 621,063	$	$	$ 621,063
Other current assets (marketable securities)	25			25
Total Assets	$ 621,088	$	$	$ 621,088
Other current liabilities (Other derivative agreements)		(853)		(853)
Total Liabilities	$	$ (853)	$	$ (853)

	December 31, 2010 (in thousands)			
	Level 1	Level 2	Level 3	Total
Location and Description				
Cash equivalents (money market account)	$ 70,052	$	$	$ 70,052
Other current assets (marketable securities)	26			26
Total Assets	$ 70,078	$	$	$ 70,078
Other current liabilities (Other derivative agreements)		(4,043)		(4,043)
Total Liabilities	$	$ (4,043)	$	$ (4,043)

As of June 30, 2011, the only financial assets and liabilities that are measured at fair value on a recurring basis are the Company s money market accounts, available-for-sale marketable securities and derivative instruments. Additionally, the fair value of the Company s Notes is disclosed in Note 12 (Long-Term Debt). 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, 2011.

The Company s investments in marketable securities are classified as available-for-sale, and as a result, are reported at fair market value using quoted market prices. These marketable securities totaled approximately $25,000 as of

June 30, 2011 and are included in other current assets on the Condensed Consolidated Balance Sheet. Unrealized gains or losses, net of related income tax are reported as a component of accumulated other comprehensive income. For the six months ended June 30, 2011, the unrealized gain, net of tax, associated with these marketable securities was nominal.

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(14) Derivative Financial Instruments

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Realized gain (loss) on other derivative agreements	$ 484	$ 6,872	$ (18,364)	$ 6,956
Unrealized gain (loss) on other derivative agreements	6,448	468	3,190	1,904
Realized gain (loss) on interest rate swap agreements		(1,086)		(2,861)
Unrealized gain (loss) on interest rate swap agreements		1,085		2,830
Total gain (loss) on derivatives, net	$ 6,932	$ 7,339	$ (15,174)	$ 8,829

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 from time to time enters into various commodity derivative transactions. The Company, as further described below, entered into an interest rate swap as required by its long-term debt agreements. The interest rate swap was for the purpose of managing interest rate risk until June 30, 2010.

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.

CVR maintains a margin account to facilitate other commodity derivative activities. A portion of this account may include funds available for withdrawal. These funds are included in cash and cash equivalents within the Condensed Consolidated Balance Sheets. The maintenance margin balance is included within other current assets within the Condensed Consolidated Balance Sheets. Dependant upon the position of the open commodity derivatives, the amounts are accounted for as an other current asset or an other current liability within the Condensed Consolidated Balance Sheets. From time to time, CVR may be required to deposit additional funds into this margin account.

Interest Rate Swap CRLLC

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 $180.0 million from March 31, 2009 until March 31, 2010 and approximately $110.0 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 were 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.

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CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Interest Rate Swap CRNF

On June 30 and July 1, 2011, CRNF entered into two floating-to-fixed interest rate swap agreements for the purpose of hedging the interest rate risk associated with a portion of its $125 million floating rate term debt which matures in April 2016. The aggregate notional amount covered under these agreements totals $62.5 million (split evenly between the two agreement dates) and commences on August 12, 2011 and expires on February 12, 2016. Under the terms of the interest rate swap agreement entered into on June 30, 2011, CRNF will receive a floating rate based on three month LIBOR and pay a fixed rate of 1.94%. Under the terms of the interest rate swap agreement entered into on July 1, 2011, CRNF will receive a floating rate based on three month LIBOR and pay a fixed rate of 1.975%. Both swap agreements will be settled every 90 days. The effect of these swap agreements is to lock in a fixed rate of interest of approximately 1.96% plus the applicable margin paid to lenders over three-month LIBOR as governed by the CRNF credit agreement. If the swaps were in effect at June 30, 2011, the effective rate would be approximately 5.71% based on the current applicable margin of 3.75% over three-month LIBOR. The agreements were designated as cash flow hedges at inception and accordingly, the effective portion of the gain or loss on the swap will be initially reported as a component of accumulated other comprehensive income (loss) (AOCI), and subsequently reclassified into interest expense when the interest rate swap transaction affects earnings. The ineffective portion of the gain or loss will be recognized immediately in current interest expense.

(15) Related Party Transactions

Until February 2011, the Goldman Sachs Funds and Kelso Funds owned approximately 40% of CVR. On February 8, 2011, GS and Kelso completed a registered public offering, whereby GS sold into the public market its remaining ownership interest in CVR and Kelso substantially reduced its interest in the Company. On May 26, 2011, Kelso completed a registered public offering in which Kelso sold into the market its remaining ownership interest in CVR. As a result of these sales, the Goldman Sachs Funds and Kelso Funds are no longer stockholders of the Company.

Interest Rate Swap

On June 30, 2005, the Company entered into three Interest Rate Swap agreements with J. Aron. These swap agreements expired on June 30, 2010. As such, there was no financial statement impact for the three and six months ended June 30, 2011. Net losses totaling $0 and $0 were recognized related to these swap agreements for the three months ended June 30, 2011 and 2010, respectively, and were reflected in gain (loss) on derivatives, net in the Condensed Consolidated Statements of Operations. Net losses totaling $0 and $16,000 were recognized related to these swap agreements for the six months ended June 30, 2011 and 2010, respectively, and were reflected in gain (loss) on derivatives, net in the Condensed Consolidated Statements of Operations. 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, 2011 and December 31, 2010, the balance in the account was approximately $161.1 million and $70.1 million, respectively. For the three months ended June 30, 2011 and 2010, the account earned interest income of approximately $4,000 and $2,000, respectively. For the six months ended June 30, 2011 and 2010, the account earned interest income of approximately $9,000 and $2,000, 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 approximately $0.9 million for its services as lead bookrunner.

CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the three and six months ended June 30, 2011, the Company recognized approximately $0.3 and $0.5 million, 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.

In connection with the Offering of the Partnership, an affiliate of GS received an underwriting fee of approximately $5.7 million for its role as a joint book-running manager. In April 2011, CRNF entered into a credit facility as discussed further in Note 12 (Long-Term Debt) whereby an affiliate of GS was paid fees and expenses of approximately $2.0 million.

(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 Topic 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 in accordance with a pet coke supply agreement. 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 price the Nitrogen Fertilizer Segment pays pursuant to the pet coke supply agreement is based on the lesser of a pet coke price derived from the price received for UAN, or the UAN-based price, and a pet coke price index. The UAN-based price begins with a pet coke price of $25 per ton based on a price per ton for UAN (exclusive of transportation cost), or netback price, of $205 per ton, and adjusts up or down $0.50 per ton for every $1.00 change in the netback price. The UAN-based price has a ceiling of $40 per ton and a floor of $5 per ton. The intercompany transactions are eliminated in the Other Segment. Intercompany sales included in Petroleum Segment net sales were approximately $3.5 million and $1.8 million for the three months ended June 30, 2011 and 2010, respectively. Intercompany sales included in Petroleum Segment net sales were approximately $4.9 million and $2.2 million for the six months ended June 30, 2011 and 2010, respectively.

The Petroleum Segment recorded intercompany cost of product sold (exclusive of depreciation and amortization) for the hydrogen purchases (sales) described below under Nitrogen Fertilizer for the three months ended June 30, 2011 and 2010 of approximately $6.1 million and $(0.6 million), respectively. For the six months ended June 30, 2011 and 2010, the Petroleum Segment recorded intercompany cost of product sold (exclusive of depreciation and amortization) for the hydrogen purchases (sales) of approximately $5.3 million and $(1.1 million), 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 approximately $2.9 million and $0.6 million for the three months ended June 30, 2011 and 2010, respectively. Intercompany cost of product sold (exclusive of depreciation and amortization) for the pet coke transfer described above was approximately $3.6 million and $1.0 million for the six months ended June 30, 2011 and 2010, 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

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CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $0 and approximately $0.7 million for the three and six months ended June 30, 2011, respectively. For the three and six months ended June 30, 2011, the Nitrogen Fertilizer Segment recorded net sales generated from intercompany sales of hydrogen to the Petroleum Segment of approximately $6.1 million. For the three and six months ended June 30, 2010, the Nitrogen Fertilizer Segment recorded costs of product sold (exclusive of depreciation and amortization) from intercompany hydrogen purchases of approximately $0.6 million and $1.1 million, respectively.

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,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Net sales				
Petroleum	$ 1,376,681	$ 951,330	$ 2,487,941	$ 1,808,018
Nitrogen Fertilizer	80,673	56,346	138,050	94,631
Intersegment eliminations	(9,638)	(1,778)	(11,010)	(2,239)
Total	$ 1,447,716	$ 1,005,898	$ 2,614,981	$ 1,900,410
Cost of product sold (exclusive of depreciation and amortization)				
Petroleum	$ 1,122,763	$ 882,150	$ 2,053,046	$ 1,681,101
Nitrogen Fertilizer	9,746	11,880	17,237	16,857
Intersegment eliminations	(9,134)	(2,378)	(10,086)	(3,416)
Total	$ 1,123,375	$ 891,652	$ 2,060,197	$ 1,694,542
Direct operating expenses (exclusive of depreciation and amortization)				
Petroleum	$ 44,054	$ 41,145	$ 89,356	$ 79,534
Nitrogen Fertilizer	22,266	21,334	45,290	43,507
Other	(113)		(113)	
Total	$ 66,207	$ 62,479	$ 134,533	$ 123,041
Insurance recovery business interruption				
Petroleum	$	$	$	$
Nitrogen Fertilizer			(2,870)	

Other								
Total	$		$		$	(2,870)	$	
Net costs associated with flood								
Petroleum	$		$		$	108	$	
Nitrogen Fertilizer								
Other								
Total	$		$		$	108	$	
Depreciation and amortization								
Petroleum	$	16,966	$	16,418	$	33,882	$	32,552
Nitrogen Fertilizer		4,648		4,671		9,285		9,336
Other		429		464		887		925
Total	$	22,043	$	21,553	$	44,054	$	42,813

CVR Energy, Inc. and Subsidiaries

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in thousands)			
Operating income (loss)				
Petroleum	$ 183,537	$ 4,645	$ 289,227	$ (2,449)
Nitrogen Fertilizer	39,346	16,502	56,112	19,470
Other	(4,963)	(1,726)	(17,813)	(9,194)
Total	$ 217,920	$ 19,421	$ 327,526	$ 7,827
Capital expenditures				
Petroleum	$ 8,626	$ 4,141	$ 13,214	$ 13,250
Nitrogen Fertilizer	4,006	753	6,047	1,969
Other	1,010	516	1,718	1,607
Total	$ 13,642	$ 5,410	$ 20,979	$ 16,826

	As of June 30, 2011	As of December 31, 2010
	(in thousands)	
Total assets		
Petroleum	$ 1,136,352	$ 1,049,361
Nitrogen Fertilizer	640,740	452,165
Other	572,814	238,658
Total	$ 2,349,906	$ 1,740,184
Goodwill		
Petroleum	$	$
Nitrogen Fertilizer	40,969	40,969
Other		
Total	$ 40,969	$ 40,969

(17) Subsequent Event

On July 26, 2011, the Partnership announced a cash distribution of $0.407 per common unit for the second quarter of 2011. The distribution was prorated for the period from April 13, 2011 through June 30, 2011. It is anticipated that approximately $9.0 million will be distributed to the public common unitholders. The distribution will be paid on August 12, 2011.

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes and with the statistical information and financial data appearing in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, as well as our Annual Report on Form 10-K for the year ended December 31, 2010. Results of operations for the three and six months ended June 30, 2011 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, 2010 and in our Form 10-Q for the quarter ended March 31, 2011. Such factors include, among others:

- volatile margins in the refining industry;
- exposure to the risks associated with volatile crude oil prices;
- the availability of adequate cash and other sources of liquidity for our capital needs;
- our ability to forecast our future financial condition or results of operations and our future revenues and expenses;
- 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 and potential liabilities arising from environmental laws and regulations;

changes in our credit profile;

the cyclical nature of the nitrogen fertilizer business;

the seasonal nature of our business;

the supply and price levels of essential raw materials;

the risk of a material decline in production at our refinery and nitrogen fertilizer plant;

potential operating hazards from accidents, fire, severe weather, floods or other natural disasters;

the risk associated with governmental policies affecting the agricultural industry;

the volatile nature of ammonia, potential liability for accidents involving ammonia that cause interruption to our businesses, 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;

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

our dependence on significant customers;

the potential loss of the nitrogen fertilizer business transportation cost advantage over its competitors;

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

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

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

our significant indebtedness, including restrictions in our debt agreements; 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 independent refiner and marketer of high value transportation fuels. In addition, we own the general partner and 69.8% of the common units of CVR Partners, LP (the Partnership), a limited partnership which produces nitrogen fertilizers, ammonia and UAN.

Coffeyville Acquisition LLC (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).

As of December 31, 2010, approximately 40% of our outstanding shares were owned by certain funds affiliated with Goldman Sachs & Co. and Kelso & Company, L.P. (GS and Kelso , respectively), through their respective ownership of CALLC II and CALLC. On February 8, 2011, CALLC and CALLC II completed a sale of our common stock into the public market pursuant to a registered public offering. As a result of this offering, GS sold into the public market its remaining ownership interests in CVR Energy and Kelso substantially reduced its interest in the Company. On May 26, 2011, Kelso completed a registered public offering, whereby Kelso sold into the public market its remaining ownership interests in CVR Energy.

On April 13, 2011, the Partnership completed its initial public offering of its common units representing limited partner interests (the Offering). The Partnership sold 22,080,000 common units (such amount includes common units issued pursuant to the exercise of the underwriters over-allotment option) at a price of $16.00 per common unit, resulting in gross proceeds (including the gross proceeds from the exercise of the underwriters over-allotment option) of $353.3 million before giving effect to underwriting discounts and other offering costs. The Partnership s units are listed on the New York Stock Exchange and are traded under the symbol UAN. In connection with the Offering the Partnership paid approximately $24.7 in underwriting fees and incurred approximately $4.4 million of other offering costs. Approximately $5.7 million was paid to an affiliate of GS which was acting as a joint book-running manager. Until the completion of the February 2011 secondary offering (described above), an affiliate of GS was a stockholder and a related party of the Company. As a result of the Offering, CVR indirectly owns 69.8% of the Partnership s outstanding common units and 100% of the Partnership s general partner with its non-economic general partner interest.

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, Kansas and at throughput terminals on Magellan and NuStar Energy, LP s (NuStar) refined products distribution systems and (3) a 145,000 bpd pipeline system that transports crude oil to our refinery with 1.2 million barrels of associated company-owned storage tanks and an additional 2.7 million barrels of leased storage capacity located at Cushing, Oklahoma. The crude oil gathering system is supported by approximately 300 miles of Company owned and leased pipeline.

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.

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 and Keystone pipelines (as discussed more fully in Note 11 to the financial statements) 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 consumed crude cost discount to WTI for the second quarter of 2011 was $(5.04) per barrel compared to $(1.77) per barrel in the second quarter of 2010.

Nitrogen fertilizer business. The nitrogen fertilizer business consists of our interest in the Partnership. We own the general partner and 69.8% of the common units of the Partnership. The nitrogen fertilizer business consists of a nitrogen fertilizer manufacturing facility that is the only operation in North America that utilizes a petroleum coke, or pet coke, gasification process to produce nitrogen fertilizer. The facility includes a 1,225 ton-per-day ammonia unit, a 2,025 ton-per-day UAN unit and a gasifier complex having a capacity of 84 million standard cubic feet per day. The gasifier is a dual-train facility, with each gasifier able to function independently of the other, thereby providing redundancy and improving reliability. The nitrogen fertilizer business upgrades a majority of the ammonia it produces to higher margin UAN fertilizer, an aqueous solution of urea and ammonium nitrate which has historically commanded a premium price over ammonia. In 2010, the nitrogen fertilizer business produced 392,745 tons of ammonia, of which approximately 60% was upgraded into 578,272 tons of UAN.

The primary raw material feedstock utilized in our nitrogen fertilizer production process is pet coke, which is produced during the crude oil refining process. In contrast, substantially all of the nitrogen fertilizer businesses competitors use natural gas as their primary raw material feedstock. Historically, pet coke has been significantly less expensive than natural gas on a per ton of fertilizer produced basis and pet coke prices have been more stable when compared to natural gas prices. By using pet coke as the primary raw material feedstock instead of natural gas, the nitrogen fertilizer business has historically been the lowest cost producer and marketer of ammonia and UAN fertilizers in North America. The nitrogen fertilizer business currently purchases most of its pet coke from CVR pursuant to a long-term agreement having an initial term that ends in 2027, subject to renewal. During the past five years, over 70% of the pet coke utilized by the nitrogen fertilizer plant was produced and supplied by CVR s crude oil refinery.

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 (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 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 liquid product yield is less than total refinery throughput, the crack spread does not account for all of 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 have historically cost less than WTI. We measure the cost advantage of our crude oil slate by calculating the spread between the price of our delivered crude oil and the price of WTI. The spread is referred to as our consumed crude 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 that the actual product specifications used to determine the NYMEX 2-1-1 crack spread 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. Assuming the same rate of consumption for the three months ended June 30, 2011, a $1.00 change of natural gas pricing would have increased or decreased our natural gas costs for the quarter by $0.6 million. Assuming the same rate of consumption for the six months ended June 30, 2011, a $1.00 change in natural gas pricing would have increased or decreased our natural gas costs for the six month period by $1.6 million.

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.

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. The next turnaround for our refinery is being conducted in two separate phases. The first phase will commence and conclude in the fourth quarter of 2011. The second phase of the turnaround will commence and conclude in the first quarter of 2012.

Our refinery experienced an equipment malfunction and small fire in connection with its FCCU on December 28, 2010, which led to reduced crude throughput and repair cost of approximately $1.9 million, net of the insurance receivable recorded for the six months ended June 30, 2011. We used the resulting downtime to perform certain turnaround activities which had otherwise been scheduled for later in 2011, along with opportunistic maintenance, which cost approximately $4.0 million in total. The refinery returned to full operations on January 26, 2011. This interruption adversely impacted the production of refined products for the petroleum business in the first quarter of 2011. We estimate that approximately 1.9 million barrels of crude oil processing were lost in the first quarter of 2011 due to this incident.

Our refinery experienced a small fire at its CCR in May 2011, which led to reduced crude throughput for the second quarter of 2011. Repair costs, net of the insurance receivable, recorded for the second quarter of 2011 approximated $0.6 million. The interruption adversely impacted the production of refined products for the second quarter of 2011.

Nitrogen Fertilizer Business

In the nitrogen fertilizer business, earnings and cash flows from operations are primarily affected by the relationship between nitrogen fertilizer product prices, on-stream factors and direct operating expenses. Unlike its competitors, the nitrogen fertilizer business does not use natural gas as a feedstock and uses a minimal amount of natural gas as an energy source in its operations. As a result, volatile swings in natural gas prices have a minimal impact on its results of operations. Instead, our adjacent refinery supplies the nitrogen fertilizer business with most of the pet coke feedstock it needs pursuant to a long-term pet coke supply agreement 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, among other factors, world grain demand and production levels, changes in world population, the cost and availability of fertilizer transportation infrastructure, weather conditions, the availability of imports, and the extent of government intervention in agriculture markets.

Nitrogen fertilizer prices are also affected by local factors, including 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.

We and other competitors in the U.S. farm belt share a significant transportation cost advantage when compared to our out-of-region competitors in serving the U.S. farm belt agricultural market. In 2010, approximately 45% of the corn planted in the United States was grown within a $35/UAN ton freight train rate of the nitrogen fertilizer plant. We are therefore able to cost-effectively sell substantially all of our products in the higher margin agricultural market, whereas a significant portion of our competitors revenues is derived from the lower margin industrial market. Our location on Union Pacific s main line increases our transportation cost advantage by lowering the costs of bringing our products to customers, assuming freight rates and pipeline tariffs for U.S. Gulf Coast importers as recently in effect. Our products leave the plant either in trucks for direct shipment to customers or in railcars for destinations located principally on the Union

Pacific Railroad, and we do not incur any intermediate transfer, storage, barge freight or pipeline freight charges. We estimate that our plant enjoys a transportation cost advantage of approximately $25 per ton over competitors located in the U.S. Gulf Coast. 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 2010, the nitrogen fertilizer business upgraded approximately 60% 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 a significantly higher percentage of fixed costs than a natural gas-based fertilizer plant. Major fixed operating expenses include electrical energy, employee labor, maintenance, including contract labor, and outside services. These fixed costs have averaged approximately 86% of direct operating expenses over the 24 months ended December 31, 2010.

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 $3.0 million to $5.0 million per turnaround. The nitrogen fertilizer plant underwent a turnaround in the fourth quarter of 2010, at a cost of approximately $3.5 million. The next facility turnaround is currently scheduled for the fourth quarter of 2012.

Agreements Between CVR Energy and the Partnership

In connection with our initial public offering and the transfer of the nitrogen fertilizer business to the Partnership in October 2007, we entered into a number of agreements with the Partnership that govern the business relations between the parties. These include the pet coke supply agreement mentioned above, under which the petroleum business sells pet coke to the nitrogen fertilizer business; a services agreement, in which our management operates the nitrogen fertilizer business; a feedstock and shared services agreement, which governs the provision of feedstocks, including hydrogen, high-pressure steam, nitrogen, instrument air, oxygen and natural gas; a raw water and facilities sharing agreement, which allocates raw water resources between the two businesses; an easement agreement; an environmental agreement; and a lease agreement pursuant to which we lease office space and laboratory space to the Partnership. Certain of these agreements were amended and/or restated in connection with the Offering.

The nitrogen fertilizer business obtains most (over 70% on average during the last five years) of the pet coke it needs from our adjacent crude oil refinery pursuant to the pet coke supply agreement, and procures the remainder on the open market. The price the nitrogen fertilizer business pays pursuant to the pet coke supply agreement is based on the lesser of a pet coke price derived from the price received for UAN, or the UAN-based price, and a pet coke price index. The UAN-based price begins with a pet coke price of $25 per ton based on a price per ton for UAN (exclusive of transportation cost), or netback price, of $205 per ton, and adjusts up or down $0.50 per ton for every $1.00 change in the netback price. The UAN-based price has a ceiling of $40 per ton and a floor of $5 per ton.

Vitol Agreement

On March 30, 2011, CRRM and Vitol Inc. (Vitol) entered into a Crude Oil Supply Agreement (the Vitol Agreement). This agreement replaced the previous supply agreement between CRRM and Vitol dated December 2, 2008, as amended, which was terminated by Vitol and CRRM on March 30, 2011.

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The Vitol Agreement provides that CRRM will continue to obtain all of the crude oil for CRRM s refinery through Vitol, other than the crude oil gathered by us from Kansas, Missouri, North Dakota, Oklahoma, Wyoming and all adjacent states. CRRM and Vitol will continue to work together to identify crude oil and pricing terms that meet CRRM s crude oil requirements. CRRM and/or Vitol will negotiate the costs of each barrel of crude oil that is purchased from third-party crude oil suppliers. Vitol purchases all such crude oil, executes all third-party sourcing transactions and provides transportation and other logistical services for the subject crude oil. Vitol then sells such crude oil and delivers the same to CRRM. Title and risk of loss for all crude oil purchased by CRRM through the Vitol Agreement passes to CRRM upon delivery to the Company s Broome Station, located near Caney, Kansas. CRRM generally pays Vitol a fixed origination fee per barrel over the negotiated cost of each barrel purchased. The Vitol Agreement commenced March 30, 2011 and extends for an initial term ending December 31, 2013, but also allows for automatic renewal for successive one-year terms.

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.

Refinancing and Prior Indebtedness

On February 22, 2011, CRLLC entered into a $250.0 million asset-backed revolving credit agreement (ABL credit facility). The ABL credit facility replaced the first priority credit facility which was terminated. As a result of the termination of the first priority credit facility, we wrote-off a portion of our previously deferred financing costs of approximately $1.9 million. This write-off is reflected on the Condensed Consolidated Statement of Operations as a loss on extinguishment of debt for the six months ended June 30, 2011. In connection with the ABL credit facility, CRLLC incurred approximately $5.9 million of fees that were deferred and are to be amortized over the term of the credit facility on a straight-line basis.

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.

In connection with the fourth amendment, CRLLC incurred lender fees of approximately $4.5 million. These fees were recorded as deferred financing costs in the first quarter of 2010. In addition, CRLLC incurred third party costs of approximately $1.5 million primarily consisting of administrative and legal costs. Of the third party costs incurred, we expensed $1.1 million in 2010 and the remaining $0.4 million was recorded as additional deferred financing costs.

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, reducing our tranche D term loans outstanding principal balance to $453.3 million. In connection with these voluntary prepayments, we paid a 2.0% premium totaling $0.5 million to the lenders under our first priority credit facility. 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 connection with the issuance of the Notes, CRLLC incurred approximately $13.9 million of underwriters and third-party fees. Original issue discount (OID) approximated $4.0 million. On December 30, 2010, CRLLC made a voluntary unscheduled principal payment of $27.5 million on the First Lien Notes that resulted in a premium payment of 3.0% and a partial write-off of previously deferred financing costs and unamortized OID totaling approximately $1.6 million, which was recognized as a loss on extinguishment of debt. On May 16, 2011, CRLLC repurchased $2.7 million of the Notes at a purchase price of 103% of the outstanding principal amount.

On April 13, 2011, CRNF, as borrower, and the Partnership, as guarantor, entered into a new credit facility with a group of lenders. The credit facility includes a term loan facility of $125.0 million and a revolving credit facility of $25.0 million with an uncommitted incremental facility of up to $50.0 million. There is no scheduled amortization and the credit facility matures in April 2016. The Partnership, upon the closing of the credit facility, made a special distribution of approximately $87.2 million to CRLLC, in order to, among other things, fund the offer to purchase CRLLC s senior secured notes required upon consummation of the Offering. The credit facility will be used to finance on-going working capital, capital expenditures, letter of credit issuances and other general needs of CRNF.

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 our 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. Certain override units were fully vested during the second quarter of 2010. Subsequent to the second quarter of 2010, there was no additional expense incurred with respect to these awards. For the three months ended June 30, 2011 and 2010, we decreased compensation expense by $0.8 million and $3.0 million, respectively, as a result of the phantom and override unit share-based compensation awards. For the six months ended June 30, 2011 and 2010, we increased compensation expense by $16.0 million and $4.1 million, respectively, as a result of the phantom and override unit share-based compensation awards. Due to the divestiture of all ownership of CVR by CALLC in the second quarter of 2011, there will be no further share-based compensation expense associated with override units subsequent to the second quarter of 2011. In association with the divestiture of ownership and the distributions to the override unitholders of CALLC, the holders of phantom units received the associated payments in the second quarter of 2011. As a result, there will be no further share-based compensation expense recorded for the Phantom Unit Plans subsequent to the second quarter of 2011.

Through the Company s Long-Term Incentive Plan, shares of non-vested common stock may be awarded to the Company s employees, officers, consultants, advisors and directors. Restricted 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 restricted shares. For the three months ended June 30, 2011 and 2010, we incurred compensation expense of $2.5 million and $0.2 million, respectively, related to restricted share awards. For the six months ended June 30, 2011 and 2010, we incurred compensation expense of $4.7 million and $0.4 million, respectively, related to restricted share awards.

In connection with the Offering, the board of directors of the general partner adopted the CVR Partners, LP Long-Term Incentive Plan (CVR Partners LTIP). Awards were granted out of the CVR Partners LTIP in the second quarter of 2011. Awards granted to employees are valued at the closing unit price of the Partnership s common units on the date of grant and amortized to compensation expense on a straight-line basis over the vesting period of the awards. Awards granted to directors are considered non-employee equity-based awards and are required to be marked-to-market each reporting period until they are vested. For the three and six months ended June 30, 2011, compensation expense of approximately $0.3 million was incurred.

Fertilizer Plant Property Taxes

The nitrogen fertilizer plant received a ten year tax abatement from Montgomery County, Kansas in connection with its construction that expired on December 31, 2007. In connection with the expiration of the abatement, the county reassessed the nitrogen fertilizer plant and classified the nitrogen fertilizer plant as almost entirely real property instead of almost entirely personal property. The reassessment has resulted in an increase to annual property tax liability for the plant by an average of approximately $10.7 million per year for the years ended December 31, 2008 and December 31, 2009, and approximately $11.7 million for the year ended December 31, 2010. We do not agree with the county s classification of the nitrogen fertilizer plant and are currently disputing it before the Kansas Court of Tax Appeals (COTA). However, we have fully accrued and paid the property taxes the county claims are owed for the years ended December 31, 2010, 2009 and 2008 and have estimated and accrued for property taxes for the first six months of 2011. These amounts are reflected as a direct operating expense in the nitrogen fertilizer business financial results. An evidentiary hearing before COTA occurred during the first quarter of 2011 regarding our property tax claims for the year ended December 31, 2008. We believe it is possible that COTA may issue a ruling sometime during 2011. However, the timing of a ruling in the case is uncertain, and there can be no assurance we will receive a ruling in 2011. If we are successful in having the nitrogen fertilizer plant reclassified as personal property, in whole or in part, a portion of the accrued and paid expenses would be refunded to the nitrogen fertilizer business, which could have a material positive effect on its results of operations. If we are not successful in having the nitrogen fertilizer plant reclassified as personal property, in whole or in part, we expect that the nitrogen fertilizer business will continue to pay property taxes at elevated rates.

Noncontrolling Interest

Prior to the Offering, the noncontrolling interests represented the incentive distribution rights (IDRs) of the managing general partner. In connection with the Offering, the IDRs were purchased by the Partnership and were subsequently extinguished, eliminating the associated noncontrolling interest related to the IDRs. As a result of the Offering, CVR recorded a noncontrolling interest for the common units sold into the public market which represented an approximately 30.2% interest in the net book value of the Partnership at the time of the Offering. Effective with the Offering, CVR s noncontrolling interest reflected on the consolidated balance sheet will be impacted by approximately 30.2% of the net income of the Partnership and related distributions for each future reporting period. The revenue and expenses from the Partnership will continue to be consolidated with CVR s statement of operations based upon the fact that the general partner is owned by CRLLC, a wholly-owned subsidiary of CVR; and therefore has the ability to control the activities of the Partnership. However, the percentage of ownership held by the public unitholders will be reflected as net income attributable to noncontrolling interest in our consolidated statement of operations and will reduce consolidated net income to derive net income attributable to CVR.

Publicly Traded Partnership Expenses

We expect that our general and administrative expenses will increase due to the costs of the Partnership operating as a publicly traded company, including costs associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, investor relations activities and registrar and transfer agent fees. We estimate that

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these incremental general and administrative expenses will approximate $3.5 million per year, excluding the costs associated with the initial implementation of the Partnership s Sarbanes-Oxley Section 404 internal controls review and testing. Our historical consolidated financial statements do not reflect the impact of these expenses, which will affect the comparability of our post-offering results with our financial statements from periods prior to the completion of the Offering.

September 2010 UAN Vessel Rupture

On September 30, 2010, our nitrogen fertilizer plant experienced an interruption in operations due to a rupture of a high-pressure UAN vessel. All operations at the nitrogen fertilizer facility were immediately shut down. No one was injured in the incident. The nitrogen fertilizer facility had previously scheduled a major turnaround to begin on October 5, 2010. To minimize disruption and impact to the production schedule, the turnaround was accelerated. The turnaround was completed on October 29, 2010 with the gasification and ammonia units in operation. The fertilizer facility restarted production of UAN on November 16, 2010 and as of December 31, 2010 repairs to the facility as a result of the rupture were substantially complete. Besides adversely impacting UAN sales in the fourth quarter of 2010, the outage caused us to shift delivery of lower priced tons from the fourth quarter of 2010 to the first and second quarters of 2011.

Total gross costs recorded as of June 30, 2011 due to the incident were approximately $11.1 million for repairs and maintenance and other associated costs. We recorded an insurance receivable of $4.5 million under the property damage coverage of which approximately $4.3 million of insurance proceeds were received as of December 31, 2010 and the remaining $0.2 million was received in January 2011. Of the costs incurred, approximately $4.5 million were capitalized. We also recognized income of approximately $2.9 million from insurance proceeds received from our business interruption insurance policy in the first quarter of 2011. We received approximately $2.3 million related to the business interruption claim during the first quarter of 2011 and received the remaining $0.6 million in April 2011.

Distributions to Unitholders

The Partnership has adopted a policy pursuant to which the Partnership will distribute all of the available cash it generates each quarter, beginning with the quarter ending June 30, 2011, covering April 13, 2011 (the closing of the Offering) through June 30, 2011. Available cash for each quarter will be determined by the board of directors of the Partnership s general partner following the end of such quarter. The Partnership expects that available cash for each quarter will generally equal its cash flow from operations for the quarter, less cash needed for maintenance capital expenditures, debt service and other contractual obligations and reserves for future operating or capital needs that the board of directors of its general partner deems necessary or appropriate. Additionally, the Partnership retained cash on hand associated with prepaid sales at the close of the Offering for future distributions to common unitholders based upon the recognition into income of the prepaid sales. The board of directors of the general partner may modify the cash distribution policy at any time, and the partnership agreement does not require the Partnership to make distributions at all.

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Results of Operations

The following tables summarize the financial data and key operating statistics for CVR and our two operating segments for the three and six months ended June 30, 2011 and 2010. 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, 2010, is unaudited.

Consolidated Statement of Operations Data	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(unaudited) (in millions, except share data)			
Net sales	$ 1,447.7	$ 1,005.9	$ 2,615.0	$ 1,900.4
Cost of product sold(1)	1,123.4	891.7	2,060.2	1,694.5
Direct operating expenses(1)	66.2	62.5	134.5	123.1
Insurance recovery business interruption			(2.9)	
Selling, general and administrative expenses(1)	18.2	10.8	51.5	32.2
Net costs associated with flood(2)			0.1	
Depreciation and amortization(3)	22.0	21.5	44.1	42.8
Operating income	$ 217.9	$ 19.4	$ 327.5	$ 7.8
Other income, net	0.5	1.5	1.1	1.9
Interest expense and other financing costs	(14.2)	(12.8)	(27.4)	(22.7)
Gain (loss) on derivatives, net	6.9	7.3	(15.2)	8.8
Loss on extinguishment of debt	(0.2)	(14.6)	(2.1)	(15.1)
Income (loss) before income tax expense (benefit)	$ 210.9	$ 0.8	$ 283.9	$ (19.3)
Income tax expense (benefit)	76.7	(0.4)	103.9	(8.1)
Net income (loss)(4)	$ 134.2	$ 1.2	$ 180.0	$ (11.2)
Less: Net income (loss) attributable to noncontrolling interest	9.3		9.3	
Net income (loss) attributable to CVR Energy stockholders	124.9	1.2	170.7	(11.2)
Basic earnings (loss) per share	$ 1.44	$ 0.01	$ 1.97	$ (0.13)
Diluted earnings (loss) per share	$ 1.42	$ 0.01	$ 1.94	$ (0.13)
Weighted-average common shares outstanding:				
Basic	86,422,881	86,336,125	86,418,356	86,332,700
Diluted	87,789,351	86,506,590	87,786,288	86,332,700

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	As of June 30, 2011 (unaudited)	As of December 31, 2010
	(in millions)	
Balance Sheet Data		
Cash and cash equivalents	$ 748.0	$ 200.0
Working capital	951.4	333.6
Total assets	2,349.9	1,740.2
Total debt, including current portion	591.7	477.0
Total CVR stockholders equity	973.4	689.6
Noncontrolling interest	146.5	10.6

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(unaudited) (in millions)			
Cash Flow Data				
Net cash flow provided by (used in):				
Operating activities	$ 178.6	$ 2.2	$ 162.6	$ 45.7
Investing activities	(13.6)	(5.4)	(20.7)	(16.8)
Financing activities	417.1	28.9	406.0	(2.5)
Other Financial Data				
Capital expenditures for property, plant and equipment	$ 13.7	$ 5.4	$ 21.0	$ 16.8
Depreciation and amortization	$ 22.0	$ 21.5	$ 44.1	$ 42.8

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

(2) 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,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(unaudited) (in millions)			
Depreciation and amortization excluded from cost of product sold	$ 0.6	$ 0.7	$ 1.3	$ 1.5
Depreciation and amortization excluded from direct operating expenses	20.9	20.3	41.8	40.3
Depreciation and amortization excluded from selling, general and administrative expenses	0.5	0.5	1.0	1.0

Total depreciation and amortization	$	22.0	$	21.5	$	44.1	$	42.8

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(3) 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,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(unaudited) (in millions)			
Loss on extinguishment of debt(a)	$ 0.2	$ 14.6	$ 2.1	$ 15.1
Letter of credit expense and interest rate swap not included in interest expense(b)	0.3	1.5	1.0	3.8
Share-based compensation expense(c)	2.1	(2.8)	21.2	4.4
Major scheduled turnaround(d)	1.1	0.2	4.3	0.2

(a) On February 22, 2011, CRLLC entered into a $250.0 million ABL credit facility, as described in further detail below. The ABL credit facility replaced the first priority credit facility which was terminated. In April 2010, CRLLC issued $500.0 million aggregate principal amount of Notes as discussed further below. On May 16, 2011, CRLLC repurchased $2.7 million of the Notes at a purchase price of 103% of the outstanding principal amount. The premium paid to repurchase the Notes is included in the loss on extinguishment of debt. 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.

As a result of the termination of the first priority credit facility we wrote-off a portion of our previously deferred financing costs of approximately $1.9 million. 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.

(b) Consists of fees which are expensed to selling, general and administrative expenses in connection with letters of credit outstanding.

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

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

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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,	
	2011	2010	2011	2010
	(unaudited) (in millions, except as otherwise indicated)			
Petroleum Business Financial Results				
Net sales	$ 1,376.7	$ 951.3	$ 2,487.9	$ 1,808.0
Cost of product sold(1)	1,122.8	882.1	2,053.0	1,681.1
Direct operating expenses(1)(2)	44.0	41.2	89.4	79.5
Net costs associated with flood			0.1	
Depreciation and amortization	17.0	16.4	33.9	32.6
Gross profit(3)	$ 192.9	$ 11.6	$ 311.5	$ 14.8
Plus direct operating expenses(1)	44.0	41.2	89.4	79.5
Plus net costs associated with flood			0.1	
Plus depreciation and amortization	17.0	16.4	33.9	32.6
Refining margin(4)	253.9	69.2	434.9	126.9
Operating income (loss)	$ 183.5	$ 4.6	$ 289.2	$ (2.4)
Adjusted Petroleum EBITDA(5)	$ 208.4	$ 46.5	$ 296.6	$ 45.5
Key Operating Statistics				
Per crude oil throughput barrel:				
Refining margin(4)	$ 25.49	$ 6.70	$ 23.08	$ 6.41
Gross profit(3)	$ 19.36	$ 1.13	$ 16.53	$ 0.75
Direct operating expenses(1)(2)	$ 4.42	$ 3.99	$ 4.74	$ 4.02
Direct operating expenses per barrel sold(1)(6)	$ 4.09	$ 3.63	$ 4.45	$ 3.63
Barrels sold (barrels per day)(6)	118,435	124,486	110,860	121,016

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	Three Months Ended June 30,				Six Months Ended June 30,			
	2011		2010		2011		2010	
		%		%		%		%
Refining Throughput and Production Data (bpd)								
Throughput:								
Sweet	84,654	72.6	90,829	74.5	82,302	74.1	87,864	74.8
Light/medium sour	198	0.2	8,505	7.0	397	0.4	8,019	6.8
Heavy sour	24,634	21.2	14,097	11.6	21,416	19.3	13,425	11.4
Total crude oil throughput	109,486	94.0	113,431	93.1	104,115	93.8	109,308	93.0
All other feedstocks and blendstocks	6,973	6.0	8,436	6.9	6,923	6.2	8,209	7.0
Total throughput	116,459	100.0	121,867	100.0	111,038	100.0	117,517	100.0
Production:								
Gasoline	53,495	45.5	55,998	45.7	51,564	46.2	57,508	48.5
Distillate	48,959	41.6	51,008	41.6	45,934	41.1	48,137	40.6
Other (excluding internally produced fuel)	15,106	12.9	15,607	12.7	14,158	12.7	12,911	10.9
Total refining production (excluding internally produced fuel)	117,560	100.0	122,613	100.0	111,656	100.0	118,556	100.0
Product price (dollars per gallon):								
Gasoline	$ 3.07		$ 2.12		$ 2.86		$ 2.08	
Distillate	$ 3.14		$ 2.17		$ 3.03		$ 2.12	

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Market Indicators (dollars per barrel)				
West Texas Intermediate (WTI) NYMEX	$ 102.34	$ 78.05	$ 98.50	$ 78.46
Crude Oil Differentials:				
WTI less WTS (light/medium sour)	$ 2.51	$ 1.84	$ 3.30	$ 1.86
WTI less WCS (heavy sour)	$ 17.61	$ 13.92	$ 19.76	$ 12.19
NYMEX Crack Spreads:				
Gasoline	$ 27.85	$ 13.00	$ 22.98	$ 11.39

Heating Oil	$ 25.56	$ 10.50	$ 24.76	$ 8.89
NYMEX 2-1-1 Crack Spread	$ 26.71	$ 11.75	$ 23.87	$ 10.14
PADD II Group 3 Basis:				
Gasoline	$ (1.59)	$ (2.88)	$ (1.82)	$ (2.80)
Ultra Low Sulfur Diesel	$ 3.24	$ 2.58	$ 2.21	$ 1.13
PADD II Group 3 Product Crack:				
Gasoline	$ 26.26	$ 10.12	$ 21.16	$ 8.58
Ultra Low Sulfur Diesel	$ 28.81	$ 13.08	$ 26.97	$ 10.03
PADD II Group 3 2-1-1	$ 27.53	$ 11.60	$ 24.06	$ 9.31

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

(2) Direct operating expense is presented on a per crude oil throughput basis. In order to derive the direct operating expenses per crude oil throughput barrel, we utilize the total direct operating expenses, which do not include depreciation or amortization expense, and divide by the applicable number of crude oil throughput barrels for the period.

(3) In order to derive the gross profit per crude oil throughput barrel, we utilize the total dollar figures for gross profit as derived above and divide by the applicable number of crude oil throughput barrels for the period.

(4) 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.

(5) Adjusted Petroleum EBITDA represents petroleum operating income adjusted for FIFO impacts (favorable) unfavorable, share-based compensation, major scheduled turnaround expenses, realized gain (loss) on derivatives, net, depreciation and amortization and other income (expense). Adjusted EBITDA by operating segment results from operating income by segment adjusted for items that we believe are needed in order to evaluate results in a more comparative analysis from period to period. Adjusted EBITDA by operating segment is not a recognized term under GAAP and should not be substituted for operating income as a measure of performance but should be utilized as a supplemental measure of performance in evaluating our business. Management believes that adjusted EBITDA by operating segment provides relevant and useful information that enables investors to better understand and evaluate our ongoing operating results and allows for greater transparency in the reviewing of our overall financial, operational and economic performance. Below is a reconciliation of operating income to adjusted EBITDA for the petroleum segment for the three and six months ended June 30, 2011 and 2010:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2011	**2010**	**2011**	**2010**
	(unaudited) (in millions)		**(unaudited) (in millions)**	
Petroleum:				
Petroleum operating income	$ 183.5	$ 4.6	$ 289.2	$ (2.4)
FIFO impacts (favorable), unfavorable(a)	4.1	17.5	(21.3)	5.2
Share-based compensation	0.5	(1.0)	7.1	1.2
Major scheduled turnaround expenses(b)	1.1	0.2	4.3	0.2
Realized gain (loss) on derivatives, net	0.5	6.9	(18.4)	6.9
Loss on disposition of fixed assets	1.5	1.3	1.5	1.3
Depreciation and amortization	17.0	16.4	33.9	32.6
Other income (expense)	0.2	0.6	0.3	0.5
Adjusted Petroleum EBITDA	208.4	46.5	296.6	45.5

(a) FIFO is the petroleum business basis for determining inventory value on a GAAP basis. 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 favorable FIFO impacts when crude oil prices increase and unfavorable FIFO impacts when crude oil prices decrease. The FIFO impact is calculated based upon inventory values at the beginning of the accounting period and at the end of the accounting period. In order to derive the FIFO impact per crude oil throughput barrel, we utilize the total dollar figures for the FIFO impact and divide by the number of crude oil throughput barrels for the period.

(b) Represents expense associated with a major scheduled turnaround at our refinery.

(6) 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.

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:

Nitrogen Fertilizer Business Financial Results	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(unaudited) (in millions)			
Net sales	$ 80.7	$ 56.3	$ 138.1	$ 94.6
Cost of product sold(1)	9.7	11.9	17.2	16.9
Direct operating expenses(1)	22.3	21.3	45.3	43.5
Insurance recovery business interruption			(2.9)	
Net costs associated with flood				
Depreciation and amortization	4.7	4.7	9.3	9.3
Operating income	$ 39.3	$ 16.5	$ 56.1	$ 19.5
Adjusted Nitrogen Fertilizer EBITDA(2)	$ 45.0	$ 20.6	$ 70.9	$ 29.3

Key Operating Statistics	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(unaudited)			
Production (thousand tons):				
Ammonia (gross produced)(3)	102.3	105.2	207.6	210.3
Ammonia (net available for sale)(3)	28.2	38.7	63.4	76.9
UAN	179.4	162.9	350.0	326.7
Pet coke consumed (thousand tons)	135.8	115.5	259.9	233.1
Pet coke (cost per ton)	$ 30	$ 17	$ 23	$ 15
Sales (thousand tons)(4):				
Ammonia	33.6	50.6	60.9	81.8
UAN	166.1	172.2	345.4	327.9
Total sales	199.7	222.8	406.3	409.7
Product pricing (plant gate) (dollars per ton)(4):				
Ammonia	$ 574	$ 312	$ 570	$ 300
UAN	$ 300	$ 205	$ 252	$ 187
On-stream factor(5):				
Gasification	99.3%	92.2%	99.6%	94.0%
Ammonia	98.5%	90.4%	97.6%	92.3%
UAN	97.6%	89.1%	95.4%	89.8%
Reconciliation to net sales (dollars in millions):				

Freight in revenue	$	5.4	$	5.2	$	10.2	$	8.8
Hydrogen and other gases revenue		6.1				6.1		
Sales net plant gate		69.2		51.1		121.8		85.8
Total net sales	$	80.7	$	56.3	$	138.1	$	94.6

Market Indicators	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(unaudited)			
Natural gas NYMEX (dollars per MMBtu)	$ 4.38	$ 4.35	$ 4.29	$ 4.67
Ammonia Southern Plains (dollars per ton)	$ 604	$ 359	$ 605	$ 345
UAN Mid Cornbelt (dollars per ton)	$ 366	$ 249	$ 358	$ 246

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

(2) Adjusted Nitrogen Fertilizer EBITDA represents nitrogen fertilizer operating income adjusted for share-based compensation, major scheduled turnaround expenses, depreciation and amortization and other income (expense). Adjusted EBITDA by operating segment results from operating income by segment adjusted for items that we believe are needed in order to evaluate results in a more comparative analysis from period to period. Adjusted nitrogen fertilizer EBITDA by operating segment is not a recognized term under GAAP and should not be substituted for operating income as a measure of performance but should be utilized as a supplemental measure of performance in evaluating our business. Management believes that adjusted EBITDA by operating segment provides relevant and useful information that enables investors to better understand and evaluate our ongoing operating results and allows for greater transparency in the reviewing of our overall financial, operational and economic performance. Below is a reconciliation of operating income to adjusted EBITDA for the nitrogen fertilizer segment for the three and six months ended June 30, 2011 and 2010:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(unaudited) (in millions)		(unaudited) (in millions)	
Nitrogen Fertilizer:				
Nitrogen fertilizer operating income	$ 39.3	$ 16.5	$ 56.1	$ 19.5
Share-based compensation	0.9	(0.5)	5.5	0.6
Major scheduled turnaround expenses				
Depreciation and amortization	4.7	4.7	9.3	9.3
Other income (expense)	0.1	(0.1)		(0.1)
Adjusted Nitrogen Fertilizer EBITDA	$ 45.0	$ 20.6	$ 70.9	$ 29.3

(3) 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.

(4) 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.

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

Three Months Ended June 30, 2011 Compared to the Three Months Ended June 30, 2010

Consolidated Results of Operations

Net Sales. Consolidated net sales were $1,447.7 million for the three months ended June 30, 2011 compared to $1,005.9 million for the three months ended June 30, 2010. The increase of $441.8 million for the three months ended June 30, 2011 as compared to the three months ended June 30, 2010 was due to an increase in petroleum net sales of approximately $425.4 million that resulted primarily from higher product prices. The average sales price for gasoline was $3.07 per gallon and distillate was $3.14 per gallon for the three months ended June 30, 2011. Gasoline and distillate prices per gallon increased approximately 44.9%

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and 44.7%, respectively, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. The increase in petroleum sales were coupled with an increase in nitrogen fertilizer net sales of $24.4 million for the three months ended June 30, 2011 as compared to the three months ended June 30, 2010. The increase in nitrogen net sales was primarily due to higher average plant gate prices coupled with higher overall sales volume.

Cost of Product Sold (Exclusive of Depreciation and Amortization). Consolidated cost of product sold (exclusive of depreciation and amortization) was $1,123.4 million for the three months ended June 30, 2011 as compared to $891.7 million for the three months ended June 30, 2010. The increase of $231.7 million for the three months ended June 30, 2011 as compared to the three months ended June 30, 2010 primarily resulted from an increase in crude oil prices. On a quarter-over-quarter basis, our consumed crude oil costs increased approximately $188.7 million. The increase of crude oil costs is primarily the result of increased prices offset by a decrease in crude oil throughput on a quarter-over-quarter basis. Consumed crude oil cost per barrel increased approximately 28.5% from an average price of $76.04 per barrel for the three months ended June 30, 2010 to an average price of $97.72 per barrel for the three months ended June 30, 2011. Increases in feedstocks other than crude oil resulted in an additional cost of product sold of approximately $51.9 million. Effective January 1, 2011, our refinery was subject to the provisions of the Renewable Fuel Standards, which mandates the use of renewable fuels. To meet this mandate, the refinery must either blend renewable fuels into gasoline and diesel fuel or purchase renewable energy credits, known as Renewable Identification Numbers (RINs) in lieu of blending. As a result of this mandate, the petroleum business incurred an additional $5.0 million of expense for the three months ended June 30, 2011 which is reflected in our cost of product sold (exclusive of depreciation and amortization). Additionally, the increase in cost of product sold (exclusive of depreciation and amortization) by the petroleum business was coupled with a slight decrease of $2.2 million associated with the nitrogen fertilizer s cost of product sold (exclusive of depreciation and amortization).

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Consolidated direct operating expenses (exclusive of depreciation and amortization) were $66.2 million for the three months ended June 30, 2011 as compared to $62.5 million for the three months ended June 30, 2010. This increase of $3.7 million for the three months ended June 30, 2011 as compared to the three months ended June 30, 2010 was due to an increase in petroleum direct operating expenses of $2.8 million coupled with an increase in nitrogen fertilizer direct operating expenses of approximately $1.0 million. The increase was primarily attributable to increases in environmental ($2.2 million), turnaround ($1.0 million), chemicals ($0.4 million) and other direct operating expenses ($0.2 million). These direct operating expense increases were partially offset by decreases in expenses associated with labor ($0.7 million), insurance ($0.5 million) and property taxes ($0.5 million).

Selling, General and Administrative Expenses (Exclusive of Depreciation and Amortization). Consolidated selling, general and administrative expenses (exclusive of depreciation and amortization) were $18.2 million for the three months ended June 30, 2011 as compared to $10.8 million for the three months ended June 30, 2010. This variance was primarily the result of an increase in expenses associated with share-based compensation ($4.8 million), outside services ($0.8 million), asset write-offs ($0.8 million) and payroll ($0.6 million). The increase in our share-based compensation expense was primarily the result of additional share-based compensation awards granted in the fourth quarter of 2010 and in the second quarter of 2011, associated with awards granted out of CVR s LTIP and CVR Partners LTIP, coupled with an increase in our stock price. These increases were partially offset by a decrease in bank charges ($0.2 million).

Operating Income (loss). Consolidated operating income was $217.9 million for the three months ended June 30, 2011 as compared to operating income of $19.4 million for the three months ended June 30, 2010. For the three months ended June 30, 2011 as compared to the three months ended June 30, 2010, petroleum operating income increased $178.9 million coupled with an increase in nitrogen fertilizer operating income of $23.0 million. The increase in operating income for both the petroleum and nitrogen fertilizer businesses was the result of higher product margins. The refining margin per barrel of crude oil throughput increased from $6.70 for the three months ended

June 30, 2010 compared to $25.49 per barrel for the three months ended June 30, 2011. The increase which was due to favorable product margins was partially offset by increases in direct operating expenses (exclusive of depreciation and amortization) and selling, general and administrative expenses (exclusive of depreciation and amortization).

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Interest Expense. Consolidated interest expense for the three months ended June 30, 2011 was $14.2 million as compared to interest expense of $12.8 million for the three months ended June 30, 2010. This $1.4 million increase for the three months ended June 30, 2011 as compared to the three months ended June 30, 2010 was primarily attributable to bank interest expense of $1.3 million on the $125.0 million CRNF term loan facility and related $0.2 million of deferred financing amortization.

Gain (loss) on Derivatives, net. For the three months ended June 30, 2011, we recorded a $6.9 million gain on derivatives, net compared to a $7.3 million gain on derivatives, net for the three months ended June 30, 2010. The gain on derivatives, net for the three months ended June 30, 2011 as compared to the gain on derivatives, net for the three months ended June 30, 2010 was primarily attributable to our other derivative agreements whereby through an over-the-counter market we hedge a portion of our crude oil and finished goods inventory positions. These other derivative agreements provided a net realized and unrealized gain of approximately $6.9 million for the three months ended June 30, 2011 compared to a net realized and unrealized gain of approximately $7.3 million for the three months ended June 30, 2010. The quarter-over-quarter impacts of the interest rate swap that expired June 30, 2010 were nominal. Our other derivative agreements were primarily entered into for the purpose of mitigating our risk due to the purchase of Canadian crude oil purchased outside our intermediation agreement. This Canadian crude oil was purchased at a discount to WTI and was received and processed primarily in the second quarter of 2011. The discount received was recognized through cost of product sold (exclusive of depreciation and amortization) in the second quarter of 2011. As a result of the new agreement with Vitol effective March 30, 2011, such crude oil purchases are no longer conducted outside the framework of the Vitol Agreement.

Income Tax Expense (benefit). Income tax expense for the three months ended June 30, 2011 was $76.7 million, or 36.4% of income before income tax expense, as compared to income tax benefit of $0.4 million, or (58.5)% of income before income tax benefit, for the three months ended June 30, 2010.

The decrease in the income tax rate over the prior year income tax benefit rate 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. Also, beginning in the second quarter of 2011, the reduction of income subject to tax associated with the noncontrolling ownership interest of CVR Partners earnings reduced the effective tax rate for 2011.

Net Income (loss) Attributable to Noncontrolling Interest. Amounts reported as net income attributable to noncontrolling interest include the 30.2% interest of the publicly held common units of the Partnership.

Net Income (loss) Attributable to CVR Energy Stockholders. For the three months ended June 30, 2011, net income totaled $124.9 million as compared to a net gain of $1.2 million for the three months ended June 30, 2010. The increase of $123.7 million for the second quarter of 2011 compared to the second quarter of 2010 was primarily due to an increase in refining margins and nitrogen fertilizer margins. These impacts were partially offset by an increase in direct operating expenses (exclusive of depreciation and amortization), selling, general and administrative expenses (exclusive of depreciation and amortization), interest expense and a gain on derivatives, net in the second quarter of 2011 compared to a gain on derivatives, net for the second quarter of 2010.

Petroleum Business Results of Operations for the Three Months Ended June 30, 2011

Net Sales. Petroleum net sales were $1,376.7 million for the three months ended June 30, 2011 compared to $951.3 million for the three months ended June 30, 2010. The increase of $425.4 million during the three months ended June 30, 2011 as compared to the three months ended June 30, 2010 was primarily the result of higher product prices. Our average sales price per gallon for the three months ended June 30, 2011 for gasoline of $3.07 and distillate of $3.14 increased by approximately 44.9% and 44.7%, respectively, as compared to the three months ended June 30, 2010.

	Three Months Ended June 30, 2011			Three Months Ended June 30, 2010			Total Variance		Price	Volume
	Volume(1)	$ per barrel	Sales $(2)	Volume(1)	$ per barrel	Sales $(2)	Volume(1)	Sales $(2)	Variance	Variance
									(in millions)	
Gasoline	5.3	$ 128.87	$ 690.9	5.2	$ 88.95	$ 465.3	0.1	$ 225.6	$ 208.9	$ 16.7
Distillate	4.5	$ 132.03	$ 599.3	4.8	$ 91.24	$ 438.3	(0.3)	$ 161.0	$ 195.9	$ (34.9)
Other products	0.6	$ 91.81	$ 51.4	0.4	$ 52.53	$ 19.3	0.2	$ 32.1	$ 10.6	$ 21.5

(1) Barrels in millions

(2) Sales dollars in millions

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 $1,122.8 million for the three months ended June 30, 2011 compared to $882.1 million for the three months ended June 30, 2010. The increase of $240.7 million during the three months ended June 30, 2011 as compared to the three months ended June 30, 2010 was primarily the result of a significant increase in crude oil prices. Our average cost per barrel of crude oil consumed for the three months ended June 30, 2011 was $97.72 compared to $76.04 for the comparable period of 2010, an increase of approximately 28.5%. Sales volume of refined fuels increased by approximately 0.6% for the three months ended June 30, 2011 as compared to the three months ended June 30, 2010. The impact of FIFO accounting also impacted cost of product sold during the comparable periods. 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, 2011, we had an unfavorable FIFO inventory impact of $4.1 million compared to an unfavorable FIFO inventory impact of $17.5 million for the comparable period of 2010.

Refining margin per barrel of crude oil throughput increased from $6.70 for the three months ended June 30, 2010 to $25.49 for the three months ended June 30, 2011. Refining margin adjusted for FIFO impact was $25.90 per crude oil throughput barrel for the three months ended June 30, 2011, as compared to $8.40 per crude oil throughput barrel for the three months ended June 30, 2010. Gross profit per barrel increased to $19.36 for the three months ended June 30, 2011 as compared to gross profit per barrel of $1.13 in the equivalent period in 2010. The increase of our refining margin per barrel is due to an increase in the average sales prices of our produced gasoline and distillates, partially offset by an increase in our cost of consumed crude oil. Our average sales price of gasoline increased approximately 44.9% and our average sales price for distillates increased approximately 44.7% for the three months ended June 30, 2011 over the comparable period of 2010. Consumed crude oil costs rose due to a 31.1% increased in WTI for the three months ended June 30, 2011 over the three months ended June 30, 2010.

Effective January 1, 2011, our refinery was subject to the provisions of the Renewable Fuel Standards, which mandates the use of renewable fuels. To meet this mandate we must either blend renewable fuels into gasoline and diesel fuel or purchase renewable energy credits, known as Renewable Identification Numbers (RINs) in lieu of blending. As a result of this mandate we incurred an additional $5.0 million of expense for the three months ended June 30, 2011 which is reflected in our cost of product sold (exclusive of depreciation and amortization).

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Direct operating expenses (exclusive of depreciation and amortization) for our petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, property taxes, catalyst and chemical costs, repairs and maintenance, labor and environmental compliance costs. Petroleum direct operating expenses (exclusive of depreciation and amortization) were $44.0 million for the three months ended June 30, 2011 compared to direct operating expenses of $41.2 million for the three months ended June 30, 2010. The increase of $2.8 million for the three months ended June 30, 2011 compared to the three months ended June 30, 2010 was the result of increases in expenses primarily associated with environmental ($2.0 million), turnaround ($1.0 million), rents ($0.3 million), energy costs ($0.3 million), production chemicals ($0.3 million),

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operating supplies ($0.3 million) and other direct operating expenses ($0.1 million). Increases in direct operating expenses were partially offset by decreases in expenses primarily associated with labor ($0.7 million), insurance ($0.4 million) and repairs and maintenance ($0.4 million). On a per barrel of crude oil throughput basis, direct operating expenses per barrel of crude oil throughput for the three months ended June 30, 2011 increased to $4.42 per barrel as compared to $3.99 per barrel for the three months ended June 30, 2010.

Operating Income (loss). Petroleum operating income was $183.5 million for the three months ended June 30, 2011 as compared to operating income of $4.6 million for the three months ended June 30, 2010. This increase of $178.9 million from the three months ended June 30, 2011 as compared to the three months ended June 30, 2010 was primarily the result of an increase in the refining margin ($184.7 million). The increase in refining margin was partially offset by an increase in direct operating expenses ($2.8 million), an increase in selling, general and administrative expenses ($2.4 million) and an increase in depreciation and amortization ($0.6 million). The increase in selling, general and administrative cost is primarily attributable to an increase in share-based compensation expense and a loss associated with the write-off of certain Phillipsburg terminal assets.

Nitrogen Fertilizer Business Results of Operations for the Three Months Ended June 30, 2011

Net Sales. Nitrogen fertilizer net sales were $80.7 million for the three months ended June 30, 2011 compared to $56.3 million for the three months ended June 30, 2010. For the three months ended June 30, 2011, ammonia and UAN made up $19.8 million and $54.8 million of our net sales, respectively. This compared to ammonia and UAN net sales of $17.1 million and $39.3 million for the three months ended June 30, 2010. The increase of $24.4 million was the result of both higher average plant gate prices for both ammonia and UAN and greater hydrogen sales to the refinery offset by lower sales unit volumes for ammonia and UAN. The following table demonstrates the impact of sales volumes and pricing for ammonia, UAN and hydrogen for the quarters ended June 30, 2011 and June 30, 2010:

	Three Months Ended June 30, 2011			Three Months Ended June 30, 2010			Total Variance		Price	Volume
	Volume(1)	$ per ton(2)	Sales $(3)	Volume(1)	$ per ton(2)	Sales $(3)	Volume(1)	Sales $(3)	Variance	Variance
									(in millions)	
Ammonia	33,582	$ 590	$ 19.8	50,576	$ 338	$ 17.1	(16,994)	$ 2.7	$ 12.7	$ (10.0)
UAN	166,112	$ 330	$ 54.8	172,165	$ 228	$ 39.2	(6,053)	$ 15.6	$ 17.6	$ (2.0)
Hydrogen	630,497	$ 10	$ 6.1		$	$	630,497	$ 6.1	$	$ 6.1

(1) Sales volume in tons

(2) Includes freight charges

(3) Sales dollars in millions

The decrease in ammonia sales volume for the three months ending June 30, 2011 compared to the three months ending June 30, 2010 was primarily attributable to the exporting of hydrogen instead of producing ammonia. UAN sales volume was lower in the three months ending June 30, 2011 than the same period in 2010 due to management decisions to move product inventory in order to take advantage of anticipated price increases later in the year. On-stream factors (total number of hours operated divided by total hours in the reporting period) for the gasification, ammonia and UAN units continue to demonstrate their reliability as all increased over the second quarter of 2010 with the units reporting 99.3%, 98.5% and 97.6%, respectively, on-stream for the three months ended June 30, 2011.

On-stream rates for the second quarter of 2010 were 92.2%, 90.4% and 89.1% for the gasification, ammonia and UAN units, respectively.

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 quarter-to-quarter. The plant gate price provides a measure that is consistently comparable period to period. Average plant gate prices for the three months ended June 30, 2011 were higher for both ammonia and UAN over the comparable period of 2010, increasing 84.4% and 46.3% respectively. The price increases reflect strong farm belt market conditions. While UAN pricing in the second quarter of 2011 was higher than last year, it nevertheless was adversely impacted by the outage of a high-pressure UAN vessel that occurred in September 2010. This caused us to shift delivery of lower priced tons from the fourth quarter of 2010 to the first and second quarters of 2011.

Cost of Product Sold Exclusive of Depreciation and Amortization). Cost of product sold is primarily comprised of pet coke expense and freight and distribution expenses. Cost of product sold for the three months ended June 30, 2011 was $9.7 million compared to $11.9 million for the three months ended June 30, 2010. Besides decreased costs associated with lower ammonia and UAN sales, we experienced an increase in pet coke costs of $2.2 million and increased freight expense of $0.1 million partially offset by a decrease in hydrogen costs of $0.6 million.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Direct operating expenses include costs associated with the actual operations of our plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Direct operating expenses (exclusive of depreciation and amortization) for the three months ended June 30, 2011 were $22.3 million as compared to approximately $21.3 million for the three months ended June 30, 2010. The $1.0 million increase was primarily the result of the increase in expenses for repairs and maintenance ($2.0 million), environmental ($0.2 million) and chemical ($0.1 million), partially offset by the increase in reimbursed expenses ($0.6 million) and decreases in property taxes ($0.5 million), utilities ($0.2 million), insurance ($0.1 million) and equipment rental ($0.1 million).

Operating Income. Nitrogen fertilizer operating income was $39.3 million for the three months ended June 30, 2011 as compared to operating income of $16.5 million for the three months ended June 30, 2010. This increase of $22.8 million was primarily the result of the increase in nitrogen fertilizer margin ($26.4 million). This favorable increase was partially offset by an increase in selling, general and administrative expenses (exclusive of depreciation and amortization) ($2.7 million) and direct operating expenses (exclusive of depreciation and amortization) ($1.0 million).

Six Months Ended June 30, 2011 Compared to the Six Months Ended June 30, 2010

Consolidated Results of Operations

Net Sales. Consolidated net sales were $2,615.0 million for the six months ended June 30, 2011 compared to $1,900.4 million for the six months ended June 30, 2010. The increase of $714.6 million for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 was primarily due to an increase in petroleum net sales of $679.9 million that resulted from significantly higher product prices ($734.2 million), partially offset by slightly lower sales volume ($54.3 million). Nitrogen fertilizer net sales increased $43.5 million for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 due to higher plant gate prices ($44.7 million) partially offset by lower sales volume ($1.2 million).

Cost of Product Sold (Exclusive of Depreciation and Amortization). Consolidated cost of product sold (exclusive of depreciation and amortization) was $2,060.2 million for the six months ended June 30, 2011 as compared to $1,694.5 million for the six months ended June 30, 2010. The increase of $365.7 million for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 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, 2011 was $93.89 compared to $75.98 for the comparable period of 2010, an increase of 23.6%. Sales volume of refined fuels decreased by approximately 2.1% for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Consolidated direct operating expenses (exclusive of depreciation and amortization) were $134.5 million for the six months ended June 30, 2011 as compared to $123.1 million for the six months ended June 30, 2010. This increase of $11.4 million for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 was due to an increase in petroleum direct operating expenses of $9.9 million coupled with an increase of $1.8 million in nitrogen direct operating expenses. The increase was primarily related to turnaround ($4.1 million), repairs and maintenance ($5.3 million), environmental ($2.3 million), labor ($1.7 million), chemicals ($0.8 million) and operating supplies ($0.8 million). These increases were partially offset by decreases in energy and utilities ($2.0 million), insurance ($0.8 million) and outside services and other direct operating expenses ($0.2 million).

Selling, General and Administrative Expenses (Exclusive of Depreciation and Amortization). Consolidated selling, general and administrative expenses were $51.5 million for the six months ended June 30, 2011 as compared to $32.2 million for the six months ended June 30, 2010. This variance was primarily the result of an increase in expenses associated with share-based compensation ($15.8 million), administrative payroll ($1.4 million), provision for bad debt ($0.8 million), other selling, general and administrative costs ($0.6 million) and public relations ($0.3 million). These increases were partially offset by decreases in insurance ($0.3 million).

Operating Income (loss). Consolidated operating income was $327.5 million for the six months ended June 30, 2011 as compared to operating income of $7.8 million for the six months ended June 30, 2010. For the six months ended June 30, 2011 as compared to the six months ended June 30, 2010, petroleum operating income increased by $291.6 million and nitrogen fertilizer operating income increased by $36.6 million.

Interest Expense. Consolidated interest expense for the six months ended June 30, 2011 was $27.4 million as compared to interest expense of $22.7 million for the six months ended June 30, 2010. 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 $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%. In December 2010, we made a $27.5 million payment on the Notes and in May 2011, repurchased $2.7 million of the Notes, thus reducing the principal balance outstanding. The weighted average interest rate of the Notes for the six months ended June 30, 2011 was approximately 9.89%. Interest expense related to the $125.0 million CRNF term loan facility was $1.3 million and $0 for the six months ended June 30, 2011 and 2010. For the six months ended June 30, 2011, amortization of deferred financing cost totaled $2.3 million compared to $1.5 million for the six months ended June 30, 2010. The increase in amortization for the six months ended June 30, 2011 was the result of amortization of the original issue discount associated with the Notes and the deferred financing related to the CRNF term loan facility. This interest expense was partially offset by capitalized interest of approximately $0.9 million for the six months ended June 30, 2011 compared to $1.6 million for the six months ended June 30, 2010.

Gain (loss) on Derivatives, net. For the six months ended June 30, 2011, we recorded a $15.2 million loss on derivatives, net compared to a $8.8 million gain on derivatives, net for the six months ended June 30, 2010. The loss on derivatives, net for the six months ended June 30, 2011 as compared to the gain on derivatives, net for the six months ended June 30, 2010 was primarily attributable to our other derivative agreements whereby through an over-the-counter market we hedge a portion of our crude oil and finished goods inventory positions as well as fix margins on certain future production. These other derivative agreements provided a net realized and unrealized loss of approximately $15.2 million for the six months ended June 30, 2011 compared to a net realized and unrealized gain of approximately $8.8 million for the six months ended June 30, 2010. Our other derivative agreements were primarily entered into for the purpose of mitigating our risk due to the purchase of Canadian crude oil acquired outside our intermediation agreement, carrying excess inventory levels due to contango opportunities in the market or inventory fluctuations caused by unexpected changes in operations, as well as fixing margins on certain future production. The gain on derivatives of $8.8 million for the six months ended June 30, 2010 was primarily attributable to other derivative agreements entered into due to carrying excess inventories while the loss on derivatives of $15.2 million for the period ended June 30, 2011 was primarily attributable to mitigating our risk on the purchase of Canadian crude oil acquired outside our intermediation agreement. As a result of the new agreement with Vitol effective March 30, 2011, such crude oil purchases will no longer be conducted outside the framework of the Vitol Agreement.

Loss on Extinguishment of Debt. For the six months ended June 30, 2011, we recorded a $2.1 million loss on extinguishment of debt. This compares to a $15.1 million loss on extinguishment of debt for the six months ended

June 30, 2010. The loss on extinguishment of debt is the result of the $250.0 million ABL credit facility entered into on February 22, 2011. The ABL replaces the previous $150.0 million revolver and as a result the associated deferred fees were expensed.

Income Tax Expense (benefit). Income tax expense for the six months ended June 30, 2011 was approximately $103.9 million, or 36.6% of income before income tax expense, as compared to income tax benefit of approximately $8.1 million, or 42.0% of income before income tax benefit, for the six months ended June 30, 2010. The decreased income tax expense rate for the six months ended June 30, 2011 was primarily the result of the correlation of the income tax benefit to the pre-tax loss of the six months ended June 30, 2010, as well as the reduction of income subject to tax associated with the noncontrolling interest ownership interest of CVR Partners s earnings beginning April 13, 2011.

Net Income (loss) Attributable to Noncontrolling Interest. Amounts reported as net income attributable to noncontrolling interest include the 30.2% interest of the publicly held common units of the Partnership.

Net Income (loss) Attributable to CVR Energy Stockholders. For the six months ended June 30, 2011, net income was $170.7 million as compared to $11.2 million of net loss for the six months ended June 30, 2010, an increase of $181.9 million. The increase in net income for the six months ended June 30, 2011 compared to the six months ended June 30, 2010 was primarily due to the increase 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 gain on derivatives, net recorded for the six months ended June 30, 2010 compared to a loss on derivatives, net recorded for the six months ended June 30, 2011.

Petroleum Business Results of Operations for the Six Months Ended June 30, 2011

Net Sales. Petroleum net sales were $2,487.9 million for the six months ended June 30, 2011 compared to $1,808.0 million for the six months ended June 30, 2010. The increase of $679.9 million during the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 was primarily the result of significantly higher product prices which was partially offset by lower overall sales volumes. Our average sales price per gallon for the six months ended June 30, 2011 for gasoline of $2.86 and distillate of $3.03 increased by 37.7% and 43.1%, respectively, as compared to the six months ended June 30, 2010.

	Six Months Ended June 30, 2011			Six Months Ended June 30, 2010			Total Variance		Price	Volume
	Volume(1)	$ per barrel	Sales $(2)	Volume(1)	$ per barrel	Sales $(2)	Volume(1)	Sales $(2)	Variance	Variance
									(in millions)	
Gasoline	10.5	$ 120.17	$ 1,262.8	10.9	$ 87.28	$ 947.9	(0.4)	$ 314.9	$ 357.1	$ (42.2)
Distillate	8.5	$ 127.20	$ 1,082.4	8.9	$ 88.86	$ 789.7	(0.4)	$ 292.7	$ 340.7	$ (48.0)
Other Products	1.0	$ 88.02	$ 87.0	0.7	$ 54.43	$ 37.9	0.3	$ 49.1	$ 13.2	$ 35.9

(1) Barrels in millions

(2) Sales dollars in millions

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

$2,053.0 million for the six months ended June 30, 2011 compared to $1,681.1 million for the six months ended June 30, 2010. The increase of $371.9 million during the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 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, 2011 was $93.89 compared to $75.98 for the comparable period of 2010, an increase of 23.6%. Sales volume of refined fuels decreased by approximately 2.1% for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010. 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, 2011, we had a favorable FIFO inventory impact of $21.3 million compared to an unfavorable FIFO inventory impact of $5.2 million for the comparable period of 2010.

Refining margin per barrel of crude oil throughput increased from $6.41 for the six months ended June 30, 2010 to $23.08 for the six months ended June 30, 2011. Refining margin adjusted for FIFO impact was $21.95 per crude oil throughput barrel for the six months ended June 30, 2011, as compared to $6.67 per crude oil throughput barrel for the three months ended June 30, 2010. Gross profit per barrel increased to $16.53 for the six months ended June 30, 2011 as compared to gross profit per barrel of $0.75 in the equivalent period in 2010. The increase of our refining margin per barrel is due to an increase in the average sales prices of our produced gasoline and distillates, partially offset by an increase in our cost of consumed crude oil. Our average sales price of gasoline increased approximately 37.7% and our average sales price for distillates increased approximately 43.1% for the six months ended June 30, 2011 over the comparable period of 2010. Consumed crude oil costs rose due to a 25.5% increased in WTI for the six months ended June 30, 2011 over the six months ended June 30, 2010.

In order to meet the provisions of the Renewable Fuel Standards, we incurred an additional $8.5 million of expense for the six months ended June 30, 2011 from the purchase of RINs. This expense is reflected in our cost of product sold (exclusive of depreciation and amortization).

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 $89.4 million for the six months ended June 30, 2011 compared to direct operating expenses of $79.5 million for the six months ended June 30, 2010. The increase of $9.9 million for the six months ended June 30, 2011 compared to the six months ended June 30, 2010, was the result of increases in expenses primarily associated with turnaround ($4.1 million), repairs and maintenance ($2.0 million), environmental ($2.0 million), labor ($1.3 million), production chemicals ($0.8 million), operating supplies ($0.8 million), rent ($0.7 million) and other direct operating expenses ($0.3 million). The increase in turnaround expense was primarily due to opportunistic turnaround maintenance work moved up from the planned fall turnaround and preformed during the FCC unit outage in the first quarter of this year. Increases in direct operating expenses were partially offset by decreases in expenses primarily associated with utilities and energy costs ($1.5 million) and insurance ($0.6 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, 2011 increased to $4.74 per barrel as compared to $4.02 per barrel for the six months ended June 30, 2010.

Operating Income (loss). Petroleum operating income was $289.2 million for the six months ended June 30, 2011 as compared to operating loss of $2.4 million for the six months ended June 30, 2010. This increase of $291.6 million from the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 was primarily the result of a rise in the refining margin ($308.0 million). The increase in refining margin was partially offset by an increase in direct operating expenses ($9.9 million), an increase in selling, general and administrative expenses ($5.1 million), an increase in flood related costs ($0.1 million) and an increase in depreciation and amortization ($1.3 million). The increase in selling, general and administrative expenses was primarily the result of an increase in costs associated with share-based compensation.

Nitrogen Fertilizer Results of Operations for the Six Months Ended June 30, 2011

Net Sales. Nitrogen fertilizer net sales were $138.1 million for the six months ended June 30, 2011 compared to $94.6 million for the six months ended June 30, 2010. For the six months ended June 30, 2011, ammonia and UAN made up $35.7 million and $96.3 million of our net sales, respectively. This compared to ammonia and UAN net sales of $26.6 million and $68.0 million for the six months ended June 30, 2010. The increase of $43.5 million was the result of both higher average plant gate prices for both ammonia and UAN and a 5.3% increase in UAN sales unit volumes offset by higher ammonia product sales volume. The following table demonstrates the impact of sales volumes and pricing for ammonia, UAN and hydrogen for the six months ended June 30, 2011 and June 30, 2010:

	Six Months Ended June 30, 2011			Six Months Ended June 30, 2010			Total Variance		Price	Volume
	Volume(1)	$ per ton(2)	Sales $(3)	Volume(1)	$ per ton(2)	Sales $(3)	Volume(1)	Sales $(3)	Variance	Variance
									(in millions)	
Ammonia	60,904	$ 586	$ 35.7	81,791	$ 325	$ 26.6	(20,887)	$ 9.1	$ 21.3	$ (12.2)
UAN	345,426	$ 279	$ 96.3	327,923	$ 207	$ 68.0	17,503	$ 28.3	$ 23.4	$ 4.9
Hydrogen	630,497	$ 10	$ 6.1		$	$	630,497	$ 6.1	$	$ 6.1

(1) Sales volume in tons

(2) Includes freight charges

(3) Sales dollars in millions

The decrease in ammonia sales volume for the six months ended June 30, 2011 compared to the six months ending June 30, 2010 was primarily attributable to the 2010 period having higher than normal volumes after a sluggish fall season in 2009 coupled with decreased ammonia production in the second quarter of 2011 due to the exporting of hydrogen instead of producing ammonia. UAN sales volumes increased due to production levels in the six months ended June 30, 2011 over the same period in 2010 as a result of a plant outage that occurred in 2010. On-stream factors (total number of hours operated divided by total hours in the reporting period) for the gasification, ammonia and UAN units continue to demonstrate their reliability as all increased over the six months ended June 30, 2010 with the units reporting 99.6%, 97.6% and 95.4%, respectively, on-stream for the six months ended June 30, 2011. On-stream rates for the six months ending June 30, 2010 were 94.0%, 92.3% and 89.8% for the gasification, ammonia and UAN units, respectively.

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 quarter-to-quarter. The plant gate price provides a measure that is consistently comparable period to period. Average plant gate prices for the six months ended June 30, 2011 were higher for both ammonia and UAN over the comparable period of 2010, increasing 89.7% and 34.8% respectively. The price increases reflect strong farm belt market conditions. While UAN pricing in the six months ending June 30, 2011 was higher than last year, it nevertheless was adversely impacted by the outage of a high-pressure UAN vessel that occurred in September 2010. This caused us to shift delivery of lower priced tons from the fourth quarter of 2010 to the first and second quarters of 2011.

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

Cost of Product Sold. Cost of product sold is primarily comprised of pet coke expense and freight and distribution expenses. Cost of product sold for the six months ended June 30, 2011 was $17.2 million compared to $16.9 million for the six months ended June 30, 2010. Besides increased costs associated with higher UAN sales volumes and a $1.1 million increase in freight expense, we experienced an increase in pet coke costs of $2.4 million and a decrease in hydrogen costs ($0.4 million).

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Direct operating expenses include costs associated with the actual operations of our plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Direct operating expenses (exclusive of depreciation and amortization) for the six months ended June 30, 2011 were $45.3 million as compared to $43.5 million for the six months ended June 30, 2010. The $1.8 million increase was primarily the result of increases in expenses for repairs and maintenance ($3.3 million), labor ($0.4 million) and environmental ($0.3 million). These increases in direct operating expenses were partially offset by an increase in reimbursed expenses ($0.5 million) and decreases in expenses associated with utilities

($0.5 million), refractory brick amortization ($0.4 million) outside services ($0.4 million) equipment rental ($0.3 million) and insurance ($0.2 million).

Insurance Recovery Business Interruption. During the six months ended June 30, 2011, we recorded insurance proceeds under insurance coverage for interruption of business of $2.9 million related to the September 30, 2010 UAN vessel rupture. As of June 30, 2011, $2.9 million of the proceeds were received.

Operating Income. Nitrogen fertilizer operating income was $56.1 million for the six months ended June 30, 2011 as compared to operating income of $19.5 million for the six months ended June 30, 2010. This increase of $36.6 million was primarily the result of the increase in nitrogen fertilizer margin ($43.2 million) coupled with business interruption recoveries recorded of $2.9 million. These favorable increases were partially offset by an increase in selling, general and administrative expenses (exclusive of depreciation and amortization) ($7.7 million) and direct operating expenses (exclusive of depreciation and amortization) ($1.8 million).

Liquidity and Capital Resources

Our primary sources of liquidity currently consist of cash generated from our operating activities, existing cash and cash equivalent balances, our working capital, our ABL credit facility and CRNF s 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 petroleum 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 equivalents and improvements in our working capital, together with borrowings under our existing revolving facilities as necessary, will be sufficient to satisfy the anticipated cash requirements associated with our existing operations for at least the next twelve 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, 2011, we had consolidated cash and cash equivalents of $748.0 million, which included $229.8 million of cash and cash equivalents of the Partnership. As of June 30, 2011, we had no amounts outstanding under our ABL credit facility and aggregate availability of $218.4 million under our ABL credit facility. Our availability under the ABL credit facility is reduced by outstanding letters of credit. As of June 30, 2011, we had $31.6 million in letters of credit outstanding as provided by our ABL credit facility. As of August 3, 2011, we had approximately $218.4 million available under the ABL credit facility and CRNF had $25.0 million of availability under its credit facility. As of August 3, 2011, the Partnership had cash and cash equivalents of approximately $239.1 million and we had cash and cash equivalents (exclusive of the Partnership) of approximately $574.9 million.

In connection with the completion of the Offering, the board of directors of the general partner of the Partnership adopted a distribution policy in which the Partnership would generally distribute all of its available cash each quarter, within 45 days after the end of each quarter, beginning with the quarter ended June 30, 2011. The distributions will be made to all common unitholders. CRLLC currently holds approximately 69.8% of all common units outstanding. The amount of the distribution will be determined pursuant to the general partner s calculation of available cash for the applicable quarter. The general partner, as a non-economic interest holder, is not entitled to receive cash distributions. As a result of the general partner s distribution policy, funds held by the Partnership will not be available for CRLLC s use, and CRLLC as a unitholder will receive its applicable percentage of the distribution of funds within 45 days following each quarter. The Partnership does not have a legal obligation to pay distributions and there is no guarantee that it will pay any distributions on the units in any quarter.

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Senior Secured Notes

On April 6, 2010, CRLLC and its newly formed wholly-owned subsidiary, Coffeyville Finance Inc. (together the Issuers), completed the private offering of $275.0 million aggregate principal amount of 9.0% First Lien Senior Secured Notes due April 1, 2015 (the First Lien Notes) and $225.0 million aggregate principal amount of 10.875% Second Lien Senior Secured Notes due April 1, 2017 (the Second Lien Notes and together with the First Lien Notes, 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. On December 30, 2010, we made a voluntary unscheduled principal payment of $27.5 million on our First Lien Notes. On May 16, 2011, we repurchased $2.7 million of the Notes at a purchase price of 103% of the outstanding principal amount, as discussed below in further detail. As of June 30, 2011, the Notes had an aggregate principal balance of $469.8 million and a net carrying value of $466.5 million.

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 ABL 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 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-month 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 or 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 allowed the Company to sell, spin-off or complete an initial public offering of the Partnership, as long as the Company offers to buy back a percentage of the Notes as described in the Indentures. In April 2011, the Partnership completed an initial public offering of common units. This offering triggered a Fertilizer Business Event (as defined in the Indentures). As a result, CRLLC and Coffeyville Finance Inc. were required to offer to purchase a portion of the Notes from holders at a purchase price equal to 103.0% of the principal amount plus accrued and unpaid interest. A Fertilizer Business Event Offer was made on April 14, 2011 to purchase up to $100.0 million of the First Lien Notes and the Second Lien Notes, as required in the Indentures. Holders of the Notes had until May 16, 2011 to properly tender Notes they wish to have repurchased. The holders of $2.7 million of the Notes tendered their Notes to the Company. The Company repurchased the Notes in accordance with the terms of the tender offer.

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. We were in compliance with the covenants as of June 30, 2011.

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 ABL credit facility and certain hedge counterparties. The liens granted in connection with the Second Lien Notes are second-priority liens and rank junior to the aforementioned first-priority liens. In connection with the closing of the Offering, the Partnership and CRNF were released from their guarantees of the Notes.

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ABL Credit Facility

CRLLC entered into a $250.0 million ABL credit facility on February 22, 2011, which provides for borrowings, letter of credit issuances and a feature that permits an increase of borrowings up to $250.0 million (in the aggregate) subject to additional lender commitments. The ABL credit facility is scheduled to mature in August 2015 and will be used to finance ongoing working capital, capital expenditures, letter of credit issuances and general needs of the Company and includes, among other things, a letter of credit sublimit equal to 90% of the total commitment.

Borrowings under the facility bear interest based on a pricing grid determined by the previous quarter s excess availability. The pricing for LIBOR loans under the ABL credit facility can range from LIBOR plus a margin of 2.75% to LIBOR plus 3.0% or, for base rate loans, the prime rate plus 1.75% to prime rate plus 2.0%. Availability under the ABL credit facility is determined by a borrowing base formula supported primarily by cash and cash equivalents, certain accounts receivable and inventory.

Under its terms, the lenders under the ABL credit facility were granted a perfected, first priority security interest (subject to certain customary exceptions) in the ABL Priority Collateral (as defined in the ABL Intercreditor Agreement) and a second priority security interest (subject to certain customary exceptions) in the Note Priority Collateral (as defined in the ABL Intercreditor Agreement). In connection with the Offering, the Partnership and CRNF were released from their guarantees of the ABL credit facility.

The ABL credit facility also contains customary covenants for a financing of this type that limit, subject to certain exceptions, the incurrence of additional indebtedness, the creation of liens on assets, the ability to dispose of assets, the ability to make restricted payments, investments and acquisitions, sale-leaseback transactions and affiliate transactions. The facility also contains a fixed charge coverage ratio financial covenant that is triggered when borrowing base excess availability is less than certain thresholds, as defined under the facility. We were in compliance with the covenants of the ABL credit facility as of June 30, 2011.

CRNF Credit Facility

On April 13, 2011, CRNF, as borrower, and the Partnership, as guarantor, entered into a new credit facility (the credit facility) with a group of lenders including Goldman Sachs Lending Partners LLC, as administrative and collateral agent. The credit facility includes a term loan facility of $125.0 million and a revolving credit facility of $25.0 million with an uncommitted incremental facility of up to $50.0 million. There is no scheduled amortization and the credit facility matures in April 2016. The Partnership, upon the closing of the credit facility, made a special distribution of approximately $87.2 million to CRLLC, in order to, among other things, fund the offer to purchase CRLLC s senior secured notes required upon consummation of the Offering. The Credit Facility will be used to finance on-going working capital, capital expenditures, letter of credit issuances and general needs of CRNF.

Borrowings under the credit facility bear interest based on a pricing grid determined by the trailing four quarter leverage ratio. The initial pricing for Eurodollar rate loans under the credit facility is the Eurodollar rate plus a margin of 3.75%, or, for base rate loans, or the prime rate plus 2.75%. Under its terms, the lenders under the credit facility were granted a perfected, first priority security interest (subject to certain customary exceptions) in substantially all of the assets of CRNF and the Partnership.

The credit facility requires the Partnership to maintain (i) a minimum interest coverage ratio as of any fiscal quarter of 3.0 to 1.0 and (ii) a maximum leverage ratio of (a) as of any fiscal quarter ending after April 13, 2011 and prior to December 31, 2011, 3.50 to 1.0, and (b) as of any fiscal quarter ending on or after December 31, 2011, 3.0 to 1.0 in all cases calculated on a trailing four quarter basis. It also contains customary covenants for a financing of this type that limit, subject to certain exceptions, the incurrence of additional indebtedness or guarantees, the creation of liens on assets, the ability to dispose of assets, the ability to make restricted payments, investments and acquisitions, sale-leaseback transactions and affiliate transactions. The credit facility provides that the Partnership can make distributions to holders of its common units provided, among other things, it is in compliance with its leverage ratio and interest coverage ratio covenants

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on a pro forma basis after giving effect to any distribution and there is no default or event of default under the credit facility.

The credit facility also contains certain customary representations and warranties, affirmative covenants and events of default, including among other things, payment defaults, breach of representations and warranties, covenant defaults, cross-defaults to certain indebtedness, certain events of bankruptcy, certain events under ERISA, material judgments, actual or asserted failure of any guaranty or security document supporting the credit facility to be in force and effect, and change of control. An event of default will also be triggered if CVR Energy terminates or violates any of CVR Energy s covenants in any of the intercompany agreements between the Partnership and CVR Energy and such action has a material adverse effect on the Partnership.

Capital Spending

We divide our capital spending needs into two categories: maintenance and growth. Maintenance capital spending includes only non-discretionary maintenance projects and projects required 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. Major scheduled turnaround expenses are expensed when incurred.

The following table summarizes our total actual capital expenditures for the six months ended June 30, 2011 by operating segment and major category:

	Six Months Ended June 30, 2011 (in millions)	
Petroleum Business:		
Maintenance	$	10.3
Growth		2.9
Petroleum business total capital excluding turnaround expenditures	$	13.2
Nitrogen Fertilizer Business:		
Maintenance		4.9
Growth		1.1
Nitrogen fertilizer business total capital excluding turnaround expenditures	$	6.0
Corporate:	$	1.8
Total capital spending	$	21.0

We expect the petroleum business and corporate related capital expenditures for 2011 to be approximately $94.0 million and $3.0 million, respectively. This figure includes an estimated $23.0 million for construction of additional crude oil storage in Cushing, Oklahoma. These facilities will provide additional capacity of approximately

1,000,000 barrels of crude oil storage. Owning our own storage facilities will provide us additional operational flexibility. Additionally, the refinery turnaround is expected to commence at the beginning of the fourth quarter of 2011 and be completed in the first quarter of 2012. We expect to incur total major scheduled turnaround expenses of approximately $70.0 million in connection with the refinery turnaround, of which approximately $54.0 million of this expense is expected to be incurred in 2011.

The nitrogen fertilizer business expects capital expenditures for 2011 to be approximately $47.6 million. This includes an estimated $36.2 million for UAN expansion capital expenditures. As the Partnership consummated the Offering in April 2011, the Partnership has moved forward with the UAN expansion. Inclusive of capital spent prior to the Offering, we anticipate that the total capital spend associated with the UAN expansion will approximate $135.0 million. As of June 30, 2011, approximately $32.1 million had been spent, of which, approximately $1.1 million was spent during the six months ended June 30, 2011. The

Partnership anticipates that the UAN expansion will be completed in the first quarter of 2013. The continuation of the UAN expansion is expected to be funded by proceeds of the Offering and term loan borrowings made by the Partnership.

Our estimated capital expenditures 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 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 board of directors of the general partner of the Partnership.

Cash Flows

The following table sets forth our cash flows for the periods indicated below:

	Six Months Ended June 30,	
	2011	2010
	(unaudited) (in millions)	
Net cash provided by (used in):		
Operating activities	$ 162.6	$ 45.7
Investing activities	(20.7)	(16.8)
Financing activities	406.0	(2.5)
Net increase (decrease) in cash and cash equivalents	$ 547.9	$ 26.4

Cash Flows Provided by Operating Activities

Net cash flows provided by operating activities for the six months ended June 30, 2011 was $162.6 million. The positive cash flow from operating activities generated over this period was primarily driven by $180.0 million of net income before noncontrolling interest. This positive net income was primarily indicative of the operating margins for the period. Positive cash flows were impacted by an increase in trade working capital which resulted primarily from an increase in inventory driven by increased crude oil prices. 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 for trade working capital. The positive operating cash flow for the period was offset by unfavorable changes in trade working capital. Trade working capital for the six months ended June 30, 2011 resulted in a reduction of cash flows of $81.7 million which was primarily attributable to the increase in inventories ($68.8 million) and an increase in accounts receivable ($18.1 million), both of which were partially offset by an increase in accounts payable of $5.2 million. Other working capital activities resulted in net cash outflow of $24.7 million. Significant uses of cash for the six months ended June 30, 2011 included payments of income tax of approximately $47.8 million.

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. 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.

Cash Flows Used in Investing Activities

Net cash used in investing activities for the six months ended June 30, 2011 was $20.7 million compared to $16.8 million for the six months ended June 30, 2010. The increase in investing activities for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 was primarily the result of an increase in capital expenditures. For the six months ended June 30, 2011, nitrogen fertilizer capital expenditures increased by approximately $4.1 million compared to the six months ended June 30, 2010. For the six months ended June 30, 2011, nitrogen fertilizer capital expenditures totaled approximately $6.0 million compared to approximately $2.0 million for the six months ended June 30, 2010. Additionally, we received approximately $0.2 million of insurance proceeds in April 2011 related to the rupture of the UAN vessel that occurred on September 30, 2010.

Cash Flows Used in Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2011 was approximately $406.0 million as compared to net cash used in financing activities of $2.5 million for the six months ended June 30, 2010. The net cash provided by financing activities for the six months ended June 30, 2011 was primarily attributable to the net proceeds received of $325.1 million from the Offering. Additionally, $125.0 million of proceeds was received by the Partnership from the issuance of long-term debt. These proceeds were partially offset by cash outflows of $26.0 million by the Partnership to purchase the managing general partner s incentive distribution rights. Financing costs were also paid during the period associated with the ABL credit facility and the credit facility of CRNF of approximately $10.5 million. We repurchased $2.7 million of our Notes in accordance with the terms of a tender offer associated with the Offering. During the first quarter of 2011, we also exercised our purchase option related to a corporate asset. This option resulted in a cash outflow of approximately $4.7 million and satisfied a capital lease obligation.

For the six months ended June 30, 2011, there were no borrowings or repayments under our first priority credit facility or ABL credit facility. As of June 30, 2011, there were no short-term borrowings outstanding under the ABL credit facility. For the six months ended June 30, 2010, there were no short-term borrowings outstanding under our first priority revolving credit facility.

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, 2011 relating to the Notes, CRNF s credit facility, operating leases, capital lease obligations, unconditional purchase obligations and other specified capital and commercial commitments for the period following June 30, 2011 and thereafter. As of June 30, 2011, there were no amounts outstanding under the ABL credit facility. The following table assumes no borrowings are made under the ABL credit facility.

	Payments Due by Period (in millions)						
	Total	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**
Contractual Obligations							
Long-term debt(1)	$ 594.8	$	$	$	$	$ 247.1	$ 347.7
Operating leases(2)	22.4	3.5	7.2	5.4	3.2	1.8	1.3
Capital lease obligations(3)	0.3	0.1	0.1	0.1			
	804.4	45.1	87.6	87.6	87.7	82.0	414.4

Unconditional purchase obligations(4)(5)							
Environmental liabilities(6)	3.0	0.5	0.6	0.2	0.2	0.2	1.3
Interest payments(7)(8)	247.4	25.8	51.5	51.5	51.5	35.1	32.0
Total	$ 1,672.3	$ 75.0	$ 147.0	$ 144.8	$ 142.6	$ 366.2	$ 796.7
Other Commercial Commitments							
Standby letters of credit(9)	$ 31.6	$	$	$	$	$	$

(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, respectively, payable semi-annually. 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. In December 2010, we made a voluntary unscheduled prepayment on our First Lien Notes of $27.5 million, reducing our aggregate principal balance of the Notes to $472.5 million. On May 16, 2011, we repurchased $2.7 million of the Notes, pursuant to an offer to purchase. See Liquidity and Capital Resources Senior Secured Notes.

CRNF entered into a new credit facility in connection with the closing of the Offering. The new credit facility includes a $125.0 million term loan, which was fully drawn at closing, and a $25.0 million revolving credit facility, which was undrawn at June 30, 2011.

(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 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, (b) commitments under an electric supply agreement with the city of Coffeyville and (c) a product supply agreement with Linde.

(5) This amount includes approximately $543.5 million payable ratably over ten years pursuant to petroleum transportation service agreements between CRRM and TransCanada Keystone Pipeline, LP (TransCanada). Under the agreements, 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 TransCanada s Keystone pipeline system. On September 15, 2009, the Company filed a Statement of Claim in the Court of the Queen s Bench of Alberta, Judicial District of Calgary, to dispute the validity of the petroleum transportation service agreements. The Company and TransCanada settled this claim in March 2011. CRRM began receiving crude oil under the agreements on the terms discussed above in the first quarter of 2011.

(6) Environmental liabilities represents (a) our estimated payments required by federal and/or state environmental agencies related to closure of hazardous waste management units at our sites in Coffeyville and Phillipsburg, Kansas and (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. We also have other environmental liabilities which are not contractual obligations but which would be necessary for our continued operations.

(7) Interest payments for the Notes 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.

(8) Interest payments related to CRNF credit facility based on current interest rates at June 30, 2011 and assume no borrowings under the revolving credit facility.

(9) Standby letters of credit include $0.2 million of letters of credit issued in connection with environmental liabilities and $31.3 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, 2011.

Recent Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, *Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,* (ASU 2011-04). ASU 2011-04 changes the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements to ensure consistency between U.S. GAAP and

International Financial Reporting Standards (IFRS). ASU 2011-04 also expands the disclosures for fair value measurements that are estimated using significant unobservable (Level 3) inputs. This new guidance is to be applied prospectively. ASU 2011-04 will be effective for interim and annual periods beginning after December 15, 2011, with early adoption permitted. We believe that the adoption of this standard will not materially expand our consolidated financial statement footnote disclosures.

In June 2011, the FASB issued ASU No. 2011-05, *Comprehensive Income (ASC Topic 220): Presentation of Comprehensive Income*, (ASU 2011-05) which amends current comprehensive income guidance. This ASU eliminates the option to present the components of other comprehensive income as part of the statement of shareholders equity. Instead, we must report comprehensive income in either a single continuous statement of comprehensive income which contains two sections, net income and other comprehensive income, or in two separate but consecutive statements. ASU 2011-05 will be effective for interim and annual periods beginning after December 15, 2011, with early adoption permitted. The adoption of ASU 2011-05 will not have a material impact on our consolidated financial statements.

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, 2010. 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, 2011 does not differ materially from that discussed under Part II Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2010. We are exposed to market pricing for all of the products sold in the future both in 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 depends, 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.

On June 30 and July 1, 2011 CRNF entered into two floating-to-fixed interest rate swap agreements for the purpose of hedging the interest rate risk associated with a portion of its $125 million floating rate term debt which matures in April 2016. The aggregate notional amount covered under these agreements totals $62.5 million (split evenly between the two agreement dates) and commences on August 12, 2011 and expires on February 12, 2016. Under the terms of the interest rate swap agreement entered into on June 30, 2011, CRNF will receive a floating rate based on three month LIBOR and pay a fixed rate of 1.94%. Under the terms of the interest rate swap agreement entered into on July 1, 2011, CRNF will receive a floating rate based on three month LIBOR and pay a fixed rate of 1.975%. Both swap agreements will be settled every 90 days. The effect of these swap agreements is to lock in a fixed rate of interest of approximately 1.96% plus the applicable margin paid to lenders over three month LIBOR as governed by the CRNF credit agreement. If the swaps were in effect at June 30, 2011, the effective rate would be approximately 5.71% based on the current applicable margin of 3.75% over LIBOR. The agreements were designated as cash flow hedges at inception and accordingly, the effective portion of the gain or loss on the swap will be initially reported as a component of accumulated other comprehensive income (loss) (AOCI), and subsequently reclassified into interest expense when the interest rate swap transaction affects earnings. The ineffective portion of the gain or loss will be recognized immediately in current interest expense.

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, 2011 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, 2011 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 Contingencies) 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, J. Aron, property tax, TransCanada and MAPL litigation contained in Litigation and for a description of the Consent Decree contained in Environmental, Health, and Safety (EHS) Matters.

Item 1A. ***Risk Factors***

There are no material changes to the risk factors previously disclosed in the Risk Factors section of our Annual Report on Form 10-K for the year ended December 31, 2010 and in our Form 10-Q for the quarter ended March 31, 2011.

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, 2011. 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 Company does not consider this to be a share buyback program.

Period	Total Number of Shares Purchased	Average PricePaid 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, 2011 to April 30, 2011				
May 1, 2011 to May 31, 2011	3,591	$ 19.54		
June 1, 2011 to June 30, 2011				
Total	3,591	$ 19.54		

Item 6. ***Exhibits***

Exhibit Number	Exhibit Title
3.1**	Amended and Restated By-Laws of CVR Energy, Inc. (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K, filed on July 20, 2011 and incorporated by reference herein).
10.1**	Amended and Restated Contribution, Conveyance and Assumption Agreement, dated as of April 7, 2011, among Coffeyville Resources, LLC, CVR GP, LLC, Coffeyville Acquisition III LLC, CVR Special GP, LLC and CVR Partners, LP (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K/A, filed on May 23, 2011 and incorporated by reference herein).
10.2**	Amended and Restated Omnibus Agreement, dated as of April 13, 2011, among CVR Energy, Inc., CVR GP, LLC and CVR Partners, LP (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K/A, filed on May 23, 2011 and incorporated by reference herein).
10.3**	Amended and Restated Services Agreement, dated as of April 13, 2011, among CVR Partners, LP, CVR GP, LLC and CVR Energy, Inc. (filed as Exhibit 10.3 to the Company s Current Report on Form 8-K/A, filed on May 23, 2011 and incorporated by reference herein).
10.4**	Amended and Restated Feedstock and Shared Services Agreement, dated as of April 13, 2011, among Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.4 to the Company s Current Report on Form 8-K/A, filed on May 23, 2011 and incorporated by reference herein).
10.5**	Amended and Restated Cross Easement Agreement, dated as of April 13, 2011, among Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.5 to the Company s Current Report on Form 8-K/A, filed on May 23, 2011 and incorporated by reference herein).
10.6**	Amended and Restated Registration Rights Agreement, dated as of April 13, 2011, among CVR Partners, LP and Coffeyville Resources, LLC (filed as Exhibit 10.6 to the Company s Current Report on Form 8-K/A, filed on May 23, 2011 and incorporated by reference herein).

10.7**	Second Amended and Restated Agreement of Limited Partnership of CVR Partners, LP, dated as of April 13, 2011 (filed as Exhibit 10.7 to the Company s Current Report on Form 8-K/A, filed on May 23, 2011 and incorporated by reference herein).
10.8**	Credit and Guaranty Agreement, dated as of April 13, 2011, among Coffeyville Resources Nitrogen Fertilizers, LLC, CVR Partners, LP, the lenders party thereto and Goldman Sachs Lending Partners LLC, as administrative agent and collateral agent (filed as Exhibit 10.8 to the Company s Current Report on Form 8-K/A, filed on May 23, 2011 and incorporated by reference herein).
10.9**	Trademark License Agreement, dated as of April 13, 2011, among CVR Energy, Inc. and CVR Partners, LP (filed as Exhibit 10.9 to the Company s Current Report on Form 8-K/A, filed on May 23, 2011 and incorporated by reference herein).
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.

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Exhibit Number	Exhibit Title
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.
101*	The following financial information for CVR Energy, Inc. s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on August 8, 2011, formatted in XBRL (Extensible Business Reporting Language) includes: (1) Condensed Consolidated Balance Sheets, (2) Condensed Consolidated Statements of Operations, (3) Condensed Consolidated Statements of Cash Flows, (4) Condensed Consolidated Statement of Changes in Equity, (5) the Notes to Condensed Consolidated Financial Statements (unaudited), tagged as blocks of text.***

* Filed herewith.

** Previously filed.

*** Users of this data are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and is otherwise not subject to liability under these sections.

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 8, 2011

By: /s/ Edward Morgan

Chief Financial Officer
(Principal Financial Officer)

August 8, 2011