CVR ENERGY INC
Form 10-Q
December 06, 2007

Table of Contents

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 September 30, 2007**
	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)*

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

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

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 86,141,291 shares of the registrant s Common Stock outstanding at December 4, 2007.

CVR ENERGY, INC. AND SUBSIDIARIES

INDEX TO QUARTERLY REPORT ON FORM 10-Q
For The Quarter Ended September 30, 2007

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

CVR ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	September 30, 2007 (Unaudited)	Pro Forma September 30, 2007 (Note 2)
ASSETS			
Current Assets:			
Cash and cash equivalents	$ 41,919,260	$ 27,318,206	$ 65,117,537
Accounts receivable, net of allowance for doubtful accounts of $375,443 and $387,078, respectively	69,589,161	65,416,983	65,416,983
Inventories	161,432,793	209,852,915	209,852,915
Prepaid expenses and other current assets	18,524,017	28,189,488	19,023,406
Insurance receivable		84,982,065	84,982,065
Income tax receivable	32,099,163	60,937,101	60,937,101
Deferred income taxes	18,888,660	99,559,780	99,559,780
Total current assets	342,453,054	576,256,538	604,889,787
Property, plant, and equipment, net of accumulated depreciation	1,007,155,873	1,164,047,449	1,164,633,272
Intangible assets, net	638,456	497,193	497,193
Goodwill	83,774,885	83,774,885	83,774,885
Deferred financing costs, net	9,128,258	8,012,476	6,720,298
Insurance receivable		11,400,000	11,400,000
Other long-term assets	6,328,989	4,579,226	4,579,226
Total assets	$ 1,449,479,515	$ 1,848,567,767	$ 1,876,494,661
LIABILITIES AND EQUITY			
Current liabilities:			
Current portion of long-term debt	$ 5,797,981	$ 57,682,429	$ 4,906,842
Revolving debt		20,000,000	
Note Payable		5,947,031	5,947,031
Payable to swap counterparty	36,894,802	241,427,327	241,427,327
Accounts payable	138,911,088	189,713,780	187,157,412
Personnel accruals	24,731,283	31,534,879	31,534,879
Accrued taxes other than income taxes	9,034,841	9,648,199	9,648,199
Deferred revenue	8,812,350	6,747,733	6,747,733

Other current liabilities	6,017,435	40,550,215	34,611,451
Total current liabilities	230,199,780	603,251,593	521,980,874
Long-term liabilities:			
Long-term debt, less current portion	769,202,019	763,447,415	486,223,002
Accrued environmental liabilities	5,395,105	5,603,884	5,603,884
Deferred income taxes	284,122,958	328,785,428	328,785,428
Payable to swap counterparty	72,806,486	99,202,285	99,202,285
Total long-term liabilities	1,131,526,568	1,197,039,012	919,814,599
Commitments and contingencies			
Minority interest in subsidiaries	4,326,188	5,169,375	10,600,000
Management voting common units subject to redemption, 201,063 units issued and outstanding in 2006 and 2007, respectively	6,980,907	8,655,762	
Members equity:			
Voting common units, 22,614,937 units issued and outstanding in 2006 and 2007, respectively	73,593,326	29,956,946	
Management nonvoting override units, 2,976,353 units issued and outstanding in 2006 and 2007, respectively	2,852,746	4,495,079	
Total members equity	76,446,072	34,452,025	
PRO FORMA STOCKHOLDERS EQUITY			
Stockholders equity:			
Common stock, $0.01 par value per share, 350,000,000 shares authorized; 86,141,291 shares issued and outstanding			861,413
Additional paid-in capital			434,529,953
Retained earnings			(11,292,178)
Total pro forma stockholders equity			424,099,188
Total liabilities and equity	$ 1,449,479,515	$ 1,848,567,767	$ 1,876,494,661

The accompanying notes are an integral part of the condensed consolidated financial statements.

Table of Contents

CVR ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
	(Unaudited)			
Net sales	$ 778,586,242	$ 585,977,758	$ 2,329,152,871	$ 1,819,873,670
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	644,627,352	446,169,603	1,848,076,557	1,319,462,926
Direct operating expenses (exclusive of depreciation and amortization)	56,695,517	44,440,204	144,461,227	218,806,288
Selling, general and administrative expenses (exclusive of depreciation and amortization)	12,326,943	14,034,765	32,796,414	42,122,058
Net costs associated with flood		32,192,342		34,331,284
Depreciation and amortization	12,787,536	10,481,065	36,809,644	42,673,523
Total operating costs and expenses	726,437,348	547,317,979	2,062,143,842	1,657,396,079
Operating income	52,148,894	38,659,779	267,009,029	162,477,591
Other income (expense):				
Interest expense and other financing costs	(10,681,064)	(18,339,731)	(33,016,684)	(45,959,154)
Interest income	1,090,792	150,610	2,773,949	763,926
Gain (Loss) on derivatives	171,208,895	40,532,495	44,746,853	(251,911,939)
Other income (expense)	573,569	52,393	310,704	154,627
Total other income (expense)	162,192,192	22,395,767	14,814,822	(296,952,540)
Income (loss) before income taxes and minority interest in subsidiaries	214,341,086	61,055,546	281,823,851	(134,474,949)
Income tax expense (benefit)	85,302,273	47,609,671	111,027,829	(93,356,611)
Minority interest in (income) loss of subsidiaries		(46,686)		210,062
Net income (loss)	$ 129,038,813	$ 13,399,189	$ 170,796,022	$ (40,908,276)
Pro Forma Information (Note 2)				
Basic earnings (loss) per common share	$ 1.50	$ 0.16	$ 1.98	$ (0.47)
Diluted earnings (loss) per common share	$ 1.50	$ 0.16	$ 1.98	$ (0.47)
	86,141,291	86,141,291	86,141,291	86,141,291

Basic weighted average common shares outstanding				
Diluted weighted average common shares outstanding	86,158,791	86,158,791	86,158,791	86,141,291

The accompanying notes are an integral part of these condensed consolidated financial statements.

Table of Contents

CVR ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
	(Unaudited)	
Cash flows from operating activities:		
Net income (loss)	$ 170,796,022	$ (40,908,276)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	36,809,644	50,300,595
Provision for doubtful accounts	2,664	11,635
Amortization of deferred financing costs	2,508,847	1,946,912
Loss on disposition of fixed assets	1,188,360	1,245,656
Forgiveness of note receivable	350,000	
Share-based compensation	1,373,624	1,642,333
Minority interest in loss of subsidiaries		(210,062)
Changes in assets and liabilities:		
Accounts receivable	23,149,463	4,160,543
Inventories	(59,782,643)	(48,420,122)
Prepaid expenses and other current assets	(16,537,977)	(2,024,037)
Insurance receivable		(96,382,065)
Other long-term assets	1,081,470	1,592,398
Accounts payable	(380,356)	82,358,374
Accrued income taxes	(16,725,901)	(28,837,938)
Deferred revenue	(6,664,314)	(2,064,617)
Other current liabilities	(7,071,516)	41,949,735
Payable to swap counterparty	(88,458,131)	230,928,324
Accrued environmental liabilities	(1,380,841)	208,779
Deferred income taxes	57,603,030	(36,008,650)
Net cash provided by operating activities	97,861,445	161,489,517
Cash flows from investing activities:		
Capital expenditures	(172,950,391)	(239,694,882)
Net cash used in investing activities	(172,950,391)	(239,694,882)
Cash flows from financing activities:		
Revolving debt payments		(241,800,000)
Revolving debt borrowings		261,800,000
Proceeds from issuance of term debt	30,000,000	50,000,000
Principal payments on long-term debt	(1,679,076)	(3,870,156)
Payment of financing costs		(2,525,533)

Issuance of members equity		20,000,000		
Payment of note receivable		150,000		
Net cash provided by financing activities		48,470,924		63,604,311
Net decrease in cash and cash equivalents		(26,618,022)		(14,601,054)
Cash and cash equivalents, beginning of period		64,703,524		41,919,260
Cash and cash equivalents, end of period	$	38,085,502	$	27,318,206
Supplemental disclosures:				
Cash paid for income taxes, net of refunds (received)	$	70,150,700	$	(28,510,023)
Cash paid for interest	$	38,229,085	$	37,363,134
Non-cash investing and financing activities:				
Accrual of construction in progress additions	$	20,195,007	$	(31,555,682)

The accompanying notes are an integral part of these condensed consolidated financial statements.

Table of Contents

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2007
(UNAUDITED)

(1) Organization, Initial Public Offering, and Basis of Presentation

Organization

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

On June 24, 2005, CALLC acquired all of the outstanding stock of Coffeyville Refining & Marketing, Inc. (CRM); Coffeyville Nitrogen Fertilizers, Inc. (CNF); Coffeyville Crude Transportation, Inc. (CCT); Coffeyville Pipeline, Inc. (CP); and Coffeyville Terminal, Inc. (CT) (collectively, CRIncs). CRIncs collectively own 100% of CL JV Holdings, LLC (CLJV) and, directly or through CLJV, they collectively own 100% of Coffeyville Resources, LLC (CRLLC) and its wholly owned subsidiaries, Coffeyville Resources Refining & Marketing, LLC (CRRM); Coffeyville Resources Nitrogen Fertilizers, LLC (CRNF); Coffeyville Resources Crude Transportation, LLC (CRCT); Coffeyville Resources Pipeline, LLC (CRP); and Coffeyville Resources Terminal, LLC (CRT).

The Company, through its wholly-owned subsidiaries, acts as an independent petroleum refiner and marketer in the mid-continental United States and a 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. See Note 15 (Business Segments) for a further discussion of the company s business segments.

CALLC formed CVR Energy, Inc. (CVR) as a wholly owned subsidiary, incorporated in Delaware in September 2006, in order to effect an initial public offering. CALLC formed Coffeyville Refining & Marketing Holdings, Inc. (Refining Holdco) as a wholly owned subsidiary, incorporated in Delaware in August 2007, by contributing its shares of CRM to Refining Holdco in exchange for its shares. Refining Holdco was formed in connection with a financing transaction in August 2007. The initial public offering of CVR was consummated on October 26, 2007. In conjunction with the initial public offering, a restructuring occurred in which CVR became a direct or indirect owner of all of the subsidiaries of CALLC. Additionally, in connection with the initial public offering, CALLC was split into two entities: Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC (CALLC II).

Initial Public Offering of CVR Energy, Inc.

On October 26, 2007, CVR Energy, Inc. completed an initial public offering of 23,000,000 shares of its common stock. The initial public offering price was $19.00 per share.

The net proceeds to CVR from the initial public offering were approximately $408.5 million, after deducting underwriting discounts and commissions, but before deduction of offering expenses. The Company also incurred approximately $11.4 million of other costs related to the initial public offering. The net proceeds from this offering were used to repay $280 million of term debt under the Company s credit facility and to repay all indebtedness under the Company s $25 million unsecured facility and $25 million secured facility, including related accrued interest through the date of repayment of approximately $5.9 million. Additionally, $50 million of net proceeds were used to repay outstanding indebtedness under the revolving loan facility under the Company s credit facility. In connection with the repayment of the $25 million unsecured facility and the $25 million secured facility, the Company will record a write-off of unamortized deferred financing fees of approximately $1.3 million in the fourth quarter of 2007.

In connection with the initial public offering, CVR became the indirect owner of the subsidiaries of CALLC and CALLC II. This was accomplished by CVR issuing 62,866,720 shares of its common stock to CALLC and CALLC II, its majority stockholders, in conjunction with the mergers of two newly formed direct subsidiaries of

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CVR into Refining Holdco and CNF. Concurrent with the merger of the subsidiaries and in accordance with a previously executed agreement, the Company s chief executive officer received 247,471 shares of CVR common stock in exchange for shares that he owned of Refining Holdco and CNF. The shares were fully vested and were exchanged at fair market value. Immediately following the completion of the offering, there were 86,141,291 shares of common stock outstanding, excluding restricted shares issued.

On October 24, 2007, 17,500 shares of restricted stock having a value of $365,400 at the date of grant were issued to outside directors. Although ownership of the shares does not transfer to the recipients until the shares have vested, recipients have dividend and voting rights on these shares from the date of grant. The fair value of each share of restricted stock was measured based on the market price of the common stock as of the date of grant and will be amortized over the respective vesting periods. One-third of the restricted stock will vest on October 24, 2008, one-third will vest on October 24, 2009, and the final one-third will vest on October 24, 2010. Options to purchase 10,300 common shares at an exercise price of $19.00 per share were granted to outside directors on October 22, 2007. These awards will vest over a three year service period and fair value will be measured using an option-pricing model at the date of grant. The Company also issued 27,100 shares of common stock to its employees on October 24, 2007 in connection with the initial public offering. The compensation expense recorded in the fourth quarter of 2007 will be $565,848 related to the shares issued.

Nitrogen Fertilizer Limited Partnership

In conjunction with the consummation of the initial public offering, CVR transferred CRNF, its nitrogen fertilizer business, to a newly created limited partnership (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). CVR concurrently sold the managing GP interest to an entity owned by its controlling stockholders and senior management at fair market value. The board of directors of CVR determined, after consultation with management, that the fair market value of the managing general partner interest was $10.6 million.

The valuation of the managing general partner interest was based on a discounted cash flow analysis, using a discount rate commensurate with the risk profile of the managing general partner interest. The key assumptions underlying the analysis were commodity price projections, which were used to determine the Partnership s raw material costs and output revenues. Other business expenses of the Partnership were based on management s projections. The Partnership s cash distributions were assumed to be flat at expected forward fertilizer prices, with cash reserves developed in periods of high prices and cash reserves reduced in periods of lower prices. The Partnership s projected cash flows due to the managing general partner under the terms of the Partnership s partnership agreement used for the valuation were modeled based on the structure of expectations of the Partnership s operations, including production volumes and operating costs, which were developed by management based on historical operations and experience. Price projections were based on information received from Blue, Johnson & Associates, a leading fertilizer industry consultant in the United States which CVR routinely uses for fertilizer market analysis.

In conjunction with CVR s ownership of the special GP interest, it will initially own all of the interests in the Partnership (other than the managing general partner interest and associated IDRs described below) and will initially be entitled to all cash that is distributed by the Partnership. The managing general partner will not be entitled to participate in Partnership distributions except in respect of associated incentive distribution rights, or IDRs, which entitle the managing general partner to receive increasing percentages of the Partnership s quarterly distributions if the Partnership increases its distributions above an amount specified in the partnership agreement. However, the Partnership is not permitted to make any distributions with respect to the IDRs until the Aggregate Adjusted Operating Surplus, as defined in the partnership agreement, generated by the Partnership during the period from its formation through December 31, 2009 has been distributed in respect of the special GP interests, which CVR will hold, and/or the Partnership s common and subordinated interests (none of which are yet outstanding, but

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

which would be issued if the Partnership issues equity in the future). In addition, there will be no distributions paid on the managing general partner s IDRs for so long as the Partnership or its subsidiaries are guarantors under CRLLC s credit facility. The Partnership and its subsidiaries are currently guarantors under CRLLC s credit facility.

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

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements were prepared in accordance with U.S. generally accepted accounting principles (GAAP) and in accordance with the rules and regulations of the Securities and Exchange Commission. The consolidated financial statements include the accounts of CVR Energy, Inc. and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. Certain information and footnotes required for the complete financial statements under GAAP have not been included pursuant to such rules and regulations. These unaudited condensed consolidated financial statements should be read in conjunction with the December 31, 2006 audited financial statements and notes thereto of CVR.

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 December 31, 2006 and September 30, 2007, the results of operations for the three and nine months ended September 30, 2006 and 2007, and the cash flows for the nine months ended September 30, 2006 and 2007.

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, 2007 or any other interim period. The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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.

(2) Pro Forma Information

Earnings per share are calculated on a pro forma basis, based upon the actual number of shares outstanding at the time of the initial public offering in October 2007. Pro forma earnings per share have been based upon the transactions that occurred to effect the initial public offering, including the merger of Refining Holdco and CNF with two of CVR s direct wholly owned subsidiaries; the effect of the 628,667.20 for 1 stock split of CVR s common stock; the issuance of 247,471 shares of common stock to CVR s chief executive officer in exchange for his shares in two of CVR s subsidiaries; the issuance of 27,100 shares of common stock to CVR s employees; and CVR s issuance of 23,000,000 shares of common stock in the offering. For the nine month period ended September 30, 2007, the 17,500 nonvested restricted shares of CVR common stock to be issued to two directors have been excluded from the calculation of pro forma diluted earnings per share because the inclusion of such shares in the number of weighted average shares outstanding would be antidilutive.

Table of Contents

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pro forma earnings (loss) per share for the three and nine month periods ended September 30, 2006 and 2007 is calculated as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006 (Unaudited)	2007 (Unaudited)	2006 (Unaudited)	2007 (Unaudited)
Net income (loss)	$ 129,038,813	$ 13,399,189	$ 170,796,022	$ (40,908,276)
Pro forma weighted average shares outstanding:				
Existing CVR common shares	100	100	100	100
Effect of 628,667.20 to 1 stock split	62,866,620	62,866,620	62,866,620	62,866,620
Issuance of common shares to management in exchange for subsidiary shares	247,471	247,471	247,471	247,471
Issuance of common shares to employees	27,100	27,100	27,100	27,100
Issuance of common shares in the initial public offering	23,000,000	23,000,000	23,000,000	23,000,000
Basic weighted average shares outstanding	86,141,291	86,141,291	86,141,291	86,141,291
Dilutive securities issuance of nonvested common shares to board of directors	17,500	17,500	17,500	
Diluted weighted average shares outstanding	86,158,791	86,158,791	86,158,791	86,141,291
Pro forma basic earnings (loss) per share	$ 1.50	$ 0.16	$ 1.98	$ (0.47)
Pro forma dilutive earnings (loss) per share	$ 1.50	$ 0.16	$ 1.98	$ (0.47)

The pro forma balance sheet assumes the following transactions occurred on September 30, 2007:

The payment of a $10.6 million dividend to the Company s shareholders of record on October 16, 2007;

The receipt of gross proceeds of $10.6 million from the sale of the managing general partner interest in the Partnership to Coffeyville Acquisition III LLC, an entity owned by related parties and management, at estimated fair market value, as determined by the board of directors after consultation with management;

The exchange of the Company s chief executive officer s shares in two of CVR s subsidiaries (Refining Holdco and CNF) for shares of CVR common stock at fair market value, resulting in an estimated step-up in basis in the Company s property, plant, and equipment of approximately $0.6 million;

The issuance of 23,000,000 shares of CVR common stock in connection with the initial public offering at an initial public offering price of $19.00 per share, resulting in aggregate gross proceeds of $437.0 million;

The payments of underwriters discounts and commissions and estimated offering expenses totaling approximately $39.9 million of which $6.6 million had been prepaid as of September 30, 2007 and $2.6 million had been accrued as of September 30, 2007;

The conversion from a partnership structure to a corporate structure;

Table of Contents

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The repayment of term debt of $280.0 million and related interest of $5.7 million with the net proceeds of the offering;

The repayment of revolver borrowings of $20.0 million, repayment of borrowings of $25 million under the unsecured facility, and repayment of borrowings of $25.0 million under the secured facility, including the related write-off of approximately $1.3 million of unamortized deferred financing fees, and the payment of related interest of $0.2 million; and

The payment of a $5.0 million termination fee to each of Goldman, Sachs & Co. and Kelso & Company, L.P. in connection with the termination of the management agreements in conjunction with the initial public offering.

(3) New Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement on Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements*, which establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 states that fair value is the price that would be received to sell the asset or paid to transfer the liability (an exit price), not the price that would be paid to acquire the asset or received to assume the liability (an entry price) . The statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company is currently evaluating the effect that this statement will have on its financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS 159). Under this standard, an entity is required to provide additional information that will assist investors and other users of financial information to more easily understand the effect of the company s choice to use fair value on its earnings. Further, the entity is required to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. This standard does not eliminate the disclosure requirements about fair value measurements included SFAS No. 107, *Disclosures about Fair Value of Financial Instruments*. SFAS 159 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating the potential adoption impact that SFAS 159 will have on its financial statements.

(4) Members Equity

Prior to CVR s initial public offering, CVR s subsidiaries were held and operated by CALLC, a limited liability company. Management of CVR holds an equity interest in CALLC as described below. Subsequent to September 30, 2007 and in connection with the split of CALLC into two entities, management s equity interest in CALLC 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. As of September 30, 2007, common units held by management contained put rights held by management and call rights held by CALLC exercisable at fair value in the event the management member became inactive. Accordingly, in accordance with Emerging Issues Task Force (EITF) Topic No. D-98, *Classification and Measurement of Redeemable Securities*, common units held by management were initially recorded at fair value at the date of issuance and have been classified in temporary equity as Management Voting Common Units Subject to Redemption (capital subject to redemption) in the accompanying condensed consolidated balance sheets. The put rights and call rights were eliminated in October 2007.

CVR accounted for changes in redemption value of management common units in the period the changes occurred and adjusted the carrying value of the capital subject to redemption to equal the redemption value at the end of each reporting period with an equal and offsetting adjustment to Members Equity. None of the capital subject to redemption was redeemable at December 31, 2006 or September 30, 2007.

At September 30, 2007, the capital subject to redemption was revalued through an independent appraisal process, and the value was determined to be $43.05 per unit. The valuation was based upon a calculation utilizing

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the initial public offering share price. This methodology provided the best estimate of the value as it was based upon actual information supporting the value. The recognition of the value of $43.05 per unit increased the carrying value of the capital subject to redemption by $2,035,354 for the nine months ended September 30, 2007 with an equal and offsetting decrease to Members Equity. The increase was primarily attributable to favorable market conditions in the fertilizer sector.

919,630 override operating units at an adjusted benchmark value of $11.31 per unit

In June 2005, CALLC issued nonvoting override operating units to certain management members holding common units. There were no required capital contributions for the override operating units.

In accordance with SFAS 123(R), *Share Based Compensation,* using the Monte Carlo method of valuation, the estimated fair value of the override operating units on June 24, 2005 was $3,604,950. Pursuant to the forfeiture schedule described below, the Company is recognizing compensation expense over the service period for each separate portion of the award for which the forfeiture restriction lapsed as if the award was, in-substance, multiple awards. Compensation expense of $177,943 and $743,137 were recognized for the three and nine month periods ending September 30, 2007, respectively. Compensation expenses of $291,679 and $865,527 were recognized for the three and nine month periods ending September 30, 2006, respectively. Significant assumptions used in the valuation were as follows:

Estimated forfeiture rate	None
Explicit service period	Based on forfeiture schedule below
Grant-date fair value controlling basis	$5.16 per share
Marketability and minority interest discounts	$1.24 per share (24% discount)
Volatility	37%

72,492 override operating units at a benchmark value of $34.72 per unit

On December 28, 2006, CALLC issued additional nonvoting override operating units to a certain management member who holds common units. There were no required capital contributions for the override operating units.

In accordance with SFAS 123(R), a combination of a binomial model and a probability-weighted expected return method which utilized the company s cash flow projections resulted in an estimated fair value of the override operating units on December 28, 2006 was $472,648. Management believed that this method was preferable for the valuation of the override units as it allowed a better integration of the cash flows with other inputs, including the timing of potential exit events that impact the estimated fair value of the override units. Pursuant to the forfeiture schedule described below, the Company is recognizing compensation expense over the service period for each separate portion of the award for which the forfeiture restriction lapsed as if the award was, in-substance, multiple awards. Compensation expense for the three and nine month periods ended September 30, 2007 was $40,532 and $236,433, respectively. Significant assumptions used in the valuation were as follows:

Estimated forfeiture rate	None

Explicit service period	Based on forfeiture schedule below
Grant-date fair value controlling basis	$8.15 per share
Marketability and minority interest discounts	$1.63 per share (20% discount)
Volatility	41%

Override operating units participate in distributions from CALLC (and, following the split of CALLC into two entities, CALLC II) in proportion to the number of total common, non-forfeited override operating and participating override value units issued. Distributions to override operating units will be reduced until the total cumulative reductions are equal to the benchmark value. Override operating units are forfeited upon termination of

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

employment for cause. In the event of all other terminations of employment, the override operating units are initially subject to forfeiture with the number of units subject to forfeiture reducing as follows:

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

On the tenth anniversary of the issuance of override operating units, such units shall convert into an equivalent number of override value units.

1,839,265 override value units at an adjusted benchmark value of $11.31 per unit

In June 2005, CALLC issued nonvoting override value units to certain management members holding common units. There were no required capital contributions for the override value units.

In accordance with SFAS 123(R), using the Monte Carlo method of valuation, the estimated fair value of the override value units on June 24, 2005 was $4,064,776. For the override value units, CVR is recognizing compensation expense ratably over the implied service period of 6 years. Compensation expense of $508,097 was recognized for both the nine months ending September 30, 2006 and 2007. Compensation expense of $169,366 was recognized for both the three months ending September, 30, 2006 and 2007. Significant assumptions used in the valuation were as follows:

Estimated forfeiture rate	None
Derived service period	6 years
Grant-date fair value controlling basis	$2.91 per share
Marketability and minority interest discounts	$0.70 per share (24% discount)
Volatility	37%

144,966 override value units at a benchmark value of $34.72 per unit

On December 28, 2006, CALLC issued additional nonvoting override value units to a certain management member who holds common units. There were no required capital contributions for the override value units.

In accordance with SFAS 123(R), a combination of a binomial model and a probability-weighted expected return method which utilized the Company s cash flow projections resulted in an estimated fair value of the override value units on December 28, 2006 of $945,178. Management believed that this method was preferable for the valuation of the override units as it allowed a better integration of the cash flows with other inputs, including the timing of potential exit events that impact the estimated fair value of the override units. For the override value units, CVR is recognizing compensation expense ratably over the implied service period of 6 years. Compensation expense for the three and nine month periods ended September 30, 2007 was $51,555 and $154,666. Significant assumptions used in the valuation were as follows:

Estimated forfeiture rate	None
Derived service period	6 years
Grant-date fair value controlling basis	$8.15 per share
Marketability and minority interest discounts	$1.63 per share (20% discount)
Volatility	41%

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Value units fully participate in cash distributions by CALLC (and, following the split of CALLC into two entities, CALLC II) when the amount of such cash distributions to certain investors (Current Common Value) is equal to four times the original contributed capital of such investors (including the Delayed Draw Capital required to be contributed pursuant to the long term credit agreements). If the Current Common Value is less than two times the original contributed capital of such investors at the time of a distribution, none of the override value units participate. In the event the Current Common Value is greater than two times the original contributed capital of such investors but less than four times, the number of participating override value units is the product of 1) the number of issued override value units and 2) a fraction, the numerator of which is the Current Common Value minus two times original contributed capital, and the denominator of which is two times the original contributed capital. Distributions to participating override value units will be reduced until the total cumulative reductions are equal to the benchmark value. On the tenth anniversary of any override value unit (including any override value unit issued on the conversion of an override operating unit) the two times threshold referenced above will become 10 times and the four times threshold referenced above will become 12 times . Unless the compensation committee of the board of directors of CALLC (and, following the split of CALLC into two entities, CALLC II) takes an action to prevent forfeiture, override value units are forfeited upon termination of employment for any reason except that in the event of termination of employment by reason of death or disability, all override value units are initially subject to forfeiture with the number of units subject to forfeiture reducing as follows:

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

At September 30, 2007, there was approximately $4.6 million of unrecognized compensation expense related to nonvoting override units. This is expected to be recognized over a period of five years as follows:

	Override Operating Units	Override Value Units
Three months ending December 31, 2007	$ 218,476	$ 220,921
Year ending December 31, 2008	670,385	883,684
Year ending December 31, 2009	344,178	883,684
Year ending December 31, 2010	102,079	883,684
Year ending December 31, 2011		385,383
	$ 1,335,118	$ 3,257,356

Phantom Unit Appreciation Plan

The Company, through a wholly-owned subsidiary, has a Phantom Unit Appreciation Plan whereby directors, employees, and service providers may be awarded phantom points at the discretion of the board of directors or the compensation committee. Holders of service phantom points have rights to receive distributions when holders of override operating units receive distributions. Holders of performance phantom points have rights to receive distributions when holders of override value units receive distributions. There are no other rights or guarantees, and the plan expires on July 25, 2015, or at the discretion of the compensation committee of the board of directors. As of September 30, 2007, the issued Profits Interest (combined phantom plan and override units) represented 15% of combined common unit interest and Profits Interest of CALLC. The Profits Interest was comprised of 11.1% and 3.9% of override interest and phantom interest, respectively. In accordance with SFAS 123(R), using the proposed initial public offering price to determine the Company s equity value, through an independent valuation process, the

Table of Contents

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

service phantom interest was valued at $39.61 per point and the performance phantom interest was valued at $39.61 per point. CVR has recorded $10,817,390 and $20,458,877 in personnel accruals as of December 31, 2006 and September 30, 2007, respectively. Compensation expense for the three and nine month periods ended September 30, 2007 related to the Phantom Unit Plan was $4,061,877 and $9,641,487, respectively. Compensation expense for the three and nine months ended September 30, 2006 related to the Phantom Unit Plan was ($475,754) and $900,496, respectively.

At September 30, 2007 there was approximately $21.1 million of unrecognized compensation expense related to the Phantom Unit Plan. This is expected to be recognized over a period of five years.

Subsequent to September 30, 2007, in connection with the Company s initial public offering, the Company has created a second phantom unit appreciation plan with respect to CALLC II which mirrors in all respects the Phantom Unit Appreciation Plan as it relates to CALLC.

(5) Inventories

Inventories consist primarily of crude oil, blending stock and components, work in progress, fertilizer products, and refined fuels and by-products. Inventories are valued at the lower of moving-average cost, which approximates the first-in, first-out (FIFO) method, or market for fertilizer products and at the lower of FIFO cost or market for refined fuels and by-products for all periods presented. Refinery unfinished and finished products inventory values were determined using the ability-to-bare process, whereby raw materials and production costs are allocated to work-in-process and finished products based on their relative fair values. Other inventories, including other raw materials, spare parts, and supplies, are valued at the lower of average cost, which approximates FIFO, or market. The cost of inventories includes inbound freight costs.

Inventories consisted of the following (in thousands):

	December 31, 2006	September 30, 2007
Finished goods	$ 59,722	$ 94,069
Raw materials and catalysts	60,810	79,507
In-process inventories	18,441	15,901
Parts and supplies	22,460	20,376
	$ 161,433	$ 209,853

(6) Planned Major Maintenance Costs

The direct-expense method of accounting is used for planned major maintenance activities. Maintenance costs are recognized as expense when maintenance services are performed. The Coffeyville nitrogen plant last completed a major scheduled turnaround in the third quarter of 2006. The Coffeyville refinery started a major scheduled turnaround in February 2007 with completion in April 2007. Costs of $76,754,014 associated with the 2007 turnaround were included in direct operating expenses (exclusive of depreciation and amortization) for the nine months ended September 30, 2007. No costs were incurred for the three months ended September 30, 2007. Costs of $4,069,189 and $4,407,137 associated primarily with the 2006 turnaround for the nitrogen plant were included in direct operating expenses (exclusive of depreciation and amortization) for the three and nine months ended September 30, 2006, respectively.

(7) 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 $595,046 and $1,791,563 for the three and nine months ended September 30, 2007, respectively.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cost of product sold excludes depreciation and amortization of $529,738 and $1,553,030 for the three and nine months ended September 30, 2006, respectively.

Direct operating expenses (exclusive of depreciation and amortization) includes direct costs of labor, maintenance and services, energy and utility costs, environmental compliance costs as well as chemicals and catalysts and other direct operating expenses. Direct operating expenses exclude depreciation and amortization of $9,582,478 and $40,201,920 for the three and nine months ended September 30, 2007, respectively. Direct operating expenses exclude depreciation and amortization of $11,682,825 and $34,528,780 for the three and nine months ended September 30, 2006, respectively. Direct operating expenses also exclude depreciation of $7,627,072 for both the three and nine months ended September 30, 2007 that is included in Net costs associated with flood on the consolidated statement of operations as a result of the assets being idled due to the flood.

Selling, general and administrative expenses (exclusive of depreciation and amortization) consist primarily of legal expenses, treasury, accounting, marketing, human resources and maintaining the corporate offices in Texas and Kansas. Selling, general and administrative expenses excludes depreciation and amortization of $303,541 and $680,040 for the three and nine months ended September 30, 2007, respectively. Selling, general and administrative expense excludes depreciation and amortization of $574,973 and $727,834 for the three and nine months ended September 30, 2006, respectively.

(8) Long-Term Debt

As a result of the flood and crude oil discharge, see Note 10, Flood , and Note 12, Commitments and Contingent Liabilities , the Company s subsidiaries entered into three new credit facilities in August 2007. Two of these facilities were subsequently repaid in full with proceeds from the initial public offering and the third facility terminated in connection with the initial public offering. CRLLC entered into a new $25 million senior secured term loan (the $25 million secured facility). The facility was secured by the same collateral that secured the Company s existing Credit Facility. Interest was payable in cash, at the Company s option, at the base rate plus 1.0% or the reserve adjusted Eurodollar rate plus 2.00%. CRLLC also entered into a new $25 million senior unsecured term loan (the $25 million unsecured facility). Interest was payable in cash, at the Company s option, at the base rate plus 1.0% or the reserve adjusted Eurodollar rate plus 2.00%. A subsidiary of CALLC, Refining Holdco, entered into a new $75 million senior unsecured term loan (the $75 million unsecured facility). Drawings could be made from time to time in amounts of at least $5 million. Interest accrued, at the borrower s option, at the base rate plus 1.50% or at the reserve adjusted Eurodollar rate plus 2.50%. Interest was paid by adding such interest to the principal amount of loans outstanding. In addition, a commitment fee equal to 1.00% accrued and was paid by adding such fees to the principal amount of loans outstanding. No amount was ever drawn on the $75 million unsecured facility.

The sole lead arranger and sole bookrunner for each of these facilities was Goldman Sachs Credit Partners L.P. The Company s obligations under the $25 million secured facility and the $25 million unsecured facility were guaranteed by substantially all of the Company s subsidiaries. The $75 million unsecured facility was guaranteed by CALLC. In addition, each of GS Capital Partners V, L.P. and Kelso Investment Associates VII, L.P. guaranteed 50% of the aggregate amount of each of the three facilities. The maturity of each of these three facilities was January 31, 2008, with an automatic extension to August 23, 2008 upon completion of an initial public offering. The secured and unsecured credit facilities were paid in full on October 26, 2007 with proceeds from CVR s initial public offering, see Note 1, Organization, Initial Public Offering, and Basis of Presentation , and both facilities were terminated. Interest accrued of approximately $0.2 million through the payment date on these two facilities was also paid with proceeds from the initial public offering. Additionally, in connection with the consummation of the initial public offering, the $75 million unsecured facility also terminated.

In connection with the repayment of the $25 million secured facility and the $25 million unsecured facility with the proceeds of CVR s initial public offering, the Company expects to write off approximately $1.3 million of deferred financing fees in the fourth quarter of 2007.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company repaid $280 million of term debt with proceeds from the initial public offering. Associated accrued interest was paid of $5.7 million. After the initial public offering, the Company had approximately $491.1 million of First Lien Tranche D term loans outstanding and $7.2 million of outstanding borrowings under its Revolving Loan Facility.

(9) Note Payable

The Company entered into an insurance premium finance agreement with Cananwill, Inc. in July 2007 to finance the purchase of its property, liability, cargo and terrorism policies. The approximately $5.9 million note will be repaid in nine equal installments with final payment in April 2008.

(10) Flood

On June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville, Kansas. As a result, the Company s refinery and nitrogen fertilizer plant were severely flooded resulting in significant damage to the refinery assets. The nitrogen fertilizer facility also sustained damage, but to a much lesser degree. The Company maintains property damage insurance which includes damage caused by a flood of up to $300 million per occurrence subject to deductibles and other limitations. The deductible associated with the property damage is $2.5 million.

Management is working closely with the Company s insurance carriers and claims adjusters to ascertain the full amount of insurance proceeds due to the Company as a result of the damages and losses. The Company has recognized a receivable from insurance at September 30, 2007 which management believes is probable of recovery from the insurance carriers. While management believes that the Company s property insurance should cover substantially all of the estimated total physical damage to the property, the Company s insurance carriers have cited potential coverage limitations and defenses that might preclude such a result.

The Company s 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 damages and losses suffered for business interruption. This coverage, however, only applies to losses incurred after a business interruption of 45 days. Because the fertilizer plant was restored to operation within this 45-day period and the refinery restarted its last operating unit in 48 days, a substantial portion of the lost profits incurred because of the flood cannot be claimed under insurance. The Company is assessing its policies to determine how much, if any, of its lost profits after the 45-day period are recoverable. No amounts for recovery of lost profits under the Company s business interruption policy have been recorded in the accompanying consolidated financial statements.

As of September 30, 2007, the Company has recorded pretax costs of approximately $34.3 million associated with the flood and related crude oil discharge as discussed in Note 12, Commitments and Contingent Liabilities , including $32.2 million in the third quarter of 2007. These amounts were net of anticipated insurance recoveries of approximately $96.4 million. The components of the net costs as of September 30, 2007 include $3.5 million for uninsured losses within the Company s insurance deductibles; $7.6 million for depreciation for the temporarily idled facilities; $5.1 million as a result of other uninsured expenses incurred which included salaries of $1.2 million, professional fees of $1.1 million and other miscellaneous amounts of $2.8 million. The $34.3 million net costs also included approximately $18.1 million recorded with respect to the environmental remediation and property damage as discussed in Note 12, Commitments and Contingent Liabilities . These costs are reported in Net costs associated with flood in the Consolidated Statements of Operations.

Total gross costs recorded due to the flood and related oil discharge that were included in the statement of operations for the three and nine months ended September 30, 2007 were approximately $128.6 million and $130.7 million. Of these gross costs for the nine month period ended September 30, 2007, approximately $91.2 million were associated with repair and other matters as a result of the flood damage to the Company s facilities. Included in this cost was $7.6 million of depreciation for temporarily idled facilities, $5.9 million of

Table of Contents

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

salaries, $2.9 million of professional fees and $74.8 million for other repair and related costs. There were approximately $39.5 million costs recorded for the nine month period ended September 30, 2007 related to the third party and property damage remediation as a result of the crude oil discharge. Total accounts receivable from insurers for flood related matters approximated $96.4 million at September 30, 2007, for which we believe collection is probable, including $21.4 million related to the crude oil discharge and $75.0 million as a result of the flood damage to the Company s facilities.

The Company anticipates that approximately $15.5 million in additional third party costs related to the repair of flood damaged property will be recorded in future periods. The total third party cost to repair the refinery is currently estimated at approximately $86 million, and the total third party cost to repair the nitrogen fertilizer facility is currently estimated at approximately $4 million. Although the Company believes that it will recover substantial sums under its insurance policies, the Company is not sure 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 difference between what the Company ultimately receives under its insurance policies compared to what has been recorded and described above could be material to the consolidated financial statements.

As of September 30, 2007, the Company had not received any insurance proceeds. As of November 30, 2007, the Company received insurance proceeds of $10 million under its property insurance policy, and an additional $10 million under its environmental policies related to recovery of certain costs associated with the crude oil discharge. See Note 12, Commitments and Contingent Liabilities for additional information regarding environmental and other contingencies relating to the crude oil discharge that occurred on July 1, 2007.

(11) Income Taxes

In June 2006, the FASB issued FASB Interpretation No. (FIN) 48, *Accounting for Uncertain Tax Positions an interpretation of FASB No. 109*. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB 109, by prescribing a minimum financial statement recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

The Company adopted the provisions of FIN 48 on January 1, 2007. The adoption of FIN 48 did not affect the Company s financial position or results of operations. The Company does not have any unrecognized tax benefits as of September 30, 2007.

Accordingly, the Company did not accrue or recognize any amounts for interest or penalties in its financial statements for the three and nine months ended September 30, 2007. The Company will classify interest to be paid on an underpayment of income taxes and any related penalties as income tax expense if it is determined, in a subsequent period, that a tax position is not more likely than not of being sustained.

CVR Energy and its subsidiaries file U.S. federal and various state income tax returns. The Company has not been subject to U.S. federal, state and local income tax examinations by tax authorities for any tax year. The U.S. federal and state tax years subject to examination are 2004 to 2006.

The Company s effective tax rate for the three and nine months ended September 30, 2007 was 78.0% and 69.4%, respectively, as compared to the federal statutory tax rate of 35%. The effective tax rate is higher primarily due to the correlation between the amount of credits which are projected to be generated for the production of ultra low sulfur diesel fuel in 2007 and the reduced level of projected pre-tax income for 2007.

The Company received credit certification from the Kansas Department of Commerce under the High Performance Incentive Program (HPIP) subsequent to September 30, 2007. Under the HPIP program, the Company anticipates that it will record a significant state income tax benefit in the fourth quarter of 2007 related to credits

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

earned on certain property placed in service for 2007 and 2006. The recognition of the credit earned will significantly increase the income tax benefit recorded in the fourth quarter of 2007.

(12) Commitments and Contingent Liabilities

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

	Operating Leases	Unconditional Purchase Obligations
Three months ending December 31, 2007	$ 871,757	$ 5,191,066
Year ending December 31, 2008	3,890,431	19,696,879
Year ending December 31, 2009	2,940,476	19,662,470
Year ending December 31, 2010	1,591,818	44,745,277
Year ending December 31, 2011	857,494	42,843,860
Year ending December 31, 2012	106,038	40,157,893
Thereafter	2,025	318,035,461
	$ 10,260,039	$ 490,332,906

The Company leases various equipment and real properties under long-term operating leases. For the three and nine months ended September 30, 2007, lease expense totaled $850,354, and $2,812,202, respectively. For the three and nine months ended September 30, 2006, lease expense totaled $985,251 and $2,823,689, 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 executed a Petroleum Transportation Service Agreement in June 2007 with TransCanada Keystone Pipeline, LP (TransCanada). TransCanada is proposing to construct, own and operate a pipeline system and a related extension and expansion of the capacity that would terminate near Cushing, Oklahoma. TransCanada has agreed to transport a contracted volume amount of at least 25,000 barrels per day with a Cushing Delivery Point as the contract point of delivery. The contract term is a 10 year period which will commence upon the completion of the pipeline system. The expected date of commencement is the fourth quarter of 2010 with termination of the transportation agreement estimated to be February 2020. The Company will pay a fixed and variable toll rate beginning during the month of commencement.

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

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. As a result of the crude oil discharge, two putative class action lawsuits (one federal and one state) were filed seeking unspecified damages with class certification under applicable law for all residents, domiciliaries and property owners of Coffeyville, Kansas who were impacted by the oil release.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company filed a motion to dismiss the federal suit for lack of subject matter jurisdiction. On November 6, 2007, the judge in the federal class action lawsuit granted the Company s motion to dismiss. Due to the uncertainty of the state suit, the Company is unable to estimate a range of possible loss at this time for this exposure in excess of the amount accrued for the proposed purchase of homes and commercial property noted below. The Company intends to defend the state suit vigorously. Presently, the Company does not expect that the resolution of the suit will have a significant adverse effect on its business and results of operations.

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 EPA on July 10, 2007. As set forth in the Consent Order, the EPA concluded that the discharge of oil from the Company s refinery caused and may continue to cause 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 Company is currently remediating the crude oil discharge and expects its remedial actions to continue until December 2007.

The Company engaged experts to assess and test the areas affected by the crude oil spill. The Company commenced a program on July 19, 2007 to purchase approximately 320 homes and other commercial properties in connection with the flood and the crude oil release. The costs recorded as of September 30, 2007 related to the obligation of the homes being purchased, were approximately $11.5 million, and are included in Net Costs Associated With Flood in the accompanying consolidated statement of operations. Costs recorded related to personal property claims were approximately $1.7 million as of September 30, 2007. The costs recorded related to estimated commercial property to be purchased and associated claims were approximately $3.6 million as of September 30, 2007. The total amount of gross costs recorded for the three and nine months ended September 30, 2007 related to the residential and commercial purchase and property claims program were approximately $16.8 million.

As of September 30, 2007, the total costs recorded for obligations other than the purchase of homes, commercial properties, and related personal property claims, approximated $22.7 million. The Company has recorded as of September 30, 2007, total costs (net of anticipated insurance recoveries recorded of $21.4 million) associated with remediation and third party property damage claims resolution of approximately $18.1 million. The Company has not estimated or accrued for, because management does not believe it is probable that there will be any potential fines, penalties or claims that may be imposed or brought by regulatory authorities or possible additional damages arising from class action lawsuits related to the flood.

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

The Company is seeking insurance coverage for this release and for the ultimate costs for remediation, property damage claims, cleanup, resolution of class action lawsuits, and other claims brought by regulatory authorities. Although the Company believes that it will recover substantial sums under its environmental and liability insurance policies, the Company is not sure 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 difference between what the Company receives under its insurance policies compared to what has been recorded and described above could be material to the consolidated financial statements. The Company has received $10 million of insurance proceeds under its environmental insurance policy as of November 30, 2007.

Environmental, Health, and Safety (EHS) Matters

CVR is 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

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and regulations. In reporting EHS liabilities, no offset is made for potential recoveries. Such liabilities include estimates of the Company s share of costs attributable to potentially responsible parties which are insolvent or otherwise unable to pay. All liabilities are monitored and adjusted regularly as new facts emerge or changes in law or technology occur.

CVR owns and/or operates manufacturing and ancillary operations at various locations directly related to petroleum refining and distribution and nitrogen fertilizer manufacturing. Therefore, CVR has exposure to potential EHS liabilities related to past and present EHS conditions at some of these locations.

The Company agreed to perform corrective action pursuant to two Administrative Orders on Consent issued to Farmland Industries, Inc. (predecessor entity to the Company) under the Resource Conservation and Recovery Act, as amended (RCRA), for the Coffeyville, Kansas refinery and Phillipsburg, Kansas terminal. In 2005, Coffeyville Resources Nitrogen Fertilizers, LLC agreed to participate in the State of Kansas Voluntary Cleanup and Property Redevelopment Program (VCPRP) to address a reported release of urea ammonium nitrate (UAN) at the Coffeyville UAN loading rack. As of December 31, 2006 and September 30, 2007, environmental accruals of $7,222,754 and $7,177,347, respectively, were reflected in the consolidated balance sheets for probable and estimated costs for remediation of environmental contamination under the RCRA Administrative Orders and the VCPRP, including amounts totaling $1,827,649 and $1,573,463, respectively, included in other current liabilities. The accruals were determined based on an estimate of payment costs through 2033, which scope of remediation was arranged with the Environmental Protection Agency (the EPA) and are discounted at the appropriate risk free rates at December 31, 2006 and September 30, 2007, respectively. The accruals include estimated closure and post-closure costs of $1,857,000 and $1,809,000 for two landfills at December 31, 2006 and September 30, 2007, respectively. The estimated future payments for these required obligations are as follows (in thousands):

	Amount
Three months ending December 31, 2007	$ 518
Year ending December 31, 2008	1,302
Year ending December 31, 2009	919
Year ending December 31, 2010	587
Year ending December 31, 2011	354
Year ending December 31, 2012	760
Thereafter	5,184
Undiscounted total	9,624
Less amounts representing interest at 4.67%	2,447
Accrued environmental liabilities at September 30, 2007	$ 7,177

In March 2004, a predecessor entity to CVR entered into a Consent Decree with the EPA and the Kansas Department of Health and Environment (KDHE) related to Farmland Industries, Inc. s prior operation of the Company s oil refinery. Under the Consent Decree, the Company agreed to install controls on certain process equipment and make certain operational changes at the refinery. As a result of this agreement to install certain controls and implement certain operational changes, the EPA and KDHE agreed not to impose civil penalties, and provided a release from liability for Farmland s alleged noncompliance with the issues addressed by the Consent Decree. Pursuant to the Consent Decree, in the short term, the Company has increased the use of catalyst additives to the fluid catalytic cracking unit at the facility to reduce emissions of SO_2. The Company will begin adding catalyst to reduce oxides of nitrogen, or NOx, in 2008. In the longer term, the Company will install controls to minimize SO_2 emissions and will install controls or otherwise reduce NOx emissions by January 1, 2011. There are other permitting, monitoring, record-keeping and reporting requirements associated with the Consent Decree. The overall cost of complying with the Consent Decree is expected to be approximately $41 million, of which approximately $35 million is expected to be capital expenditures. The estimated costs do not include the cleanup obligations that

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the Company assumed pursuant to the Consent Decree under the Administrative Orders on Consent previously described.

The EPA is continuing with its Petroleum Refining Initiative alleging industry-wide noncompliance with four marquee issues: New Source Review, flaring, leak detection and repair, and Benzene Waste Operations NESHAP. The Petroleum Refining Initiative has resulted in many refiners entering into consent decrees imposing civil penalties and requiring substantial expenditures for additional or enhanced pollution control. At this time, management does not know how, if at all, the Petroleum Refining Initiative will affect the Company as the current Consent Decree covers some, but not all, of the marquee issues.

On November 15, 2007, the Governor of Kansas, Kathleen Sebelius, signed the Midwestern Greenhouse Gas Accord, whereby six states and the Canadian Province of Manitoba agreed to endeavor to establish greenhouse gas reduction targets and develop a market-based and multi-sector cap-and-trade mechanism to achieve these reduction targets. At the time, management does not know to what extent the Midwestern Greenhouse Gas Accord will affect the Company, and its facilities that emit greenhouse gases, could be regulated.

Periodically, the Company receives communications from various federal, state and local governmental authorities asserting violation(s) of environmental laws and/or regulations. These governmental entities may also propose or assess fines or require corrective action for these asserted violations. The Company intends to respond in a timely manner to all such communications and to take appropriate corrective action. The Company does not anticipate that any such matters currently asserted will have a material adverse impact on the financial condition, results of operations or cash flows.

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.

The EPA has issued regulations intended to limit amounts of sulfur in diesel and gasoline. The EPA has granted the Company a petition for a technical hardship waiver with respect to the date for compliance in meeting the sulfur-lowering standards. CVR has spent approximately $2 million in 2004, $27 million in 2005, $79 million in 2006, $17 million in the first nine months of 2007 and, based on information currently available, anticipates spending approximately $0 million in the last three months of 2007, $5 million in 2008, $18 million in 2009, and $22 million in 2010 to comply with the low-sulfur rules. The entire amounts are expected to be capitalized.

Environmental expenditures are capitalized when such expenditures are expected to result in future economic benefits. For the nine month period ended September 30, 2006 and 2007, capital expenditures were $172,950,392 and $102,775,474, respectively, and were incurred to improve the environmental compliance and efficiency of the operations.

CVR believes 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.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(13) Derivative Financial Instruments

Loss on derivatives consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Realized loss on swap agreements	$ (12,735,079)	$ (45,351,557)	$ (46,147,786)	$ (142,566,824)
Unrealized gain (loss) on swap agreements	178,545,946	90,196,226	80,322,487	(98,294,206)
Realized gain (loss) on other agreements	8,809,112	(1,246,747)	6,146,779	(8,833,758)
Unrealized gain (loss) on other agreements	1,127,332	726,178	1,530,184	(837,339)
Realized gain on interest rate swap agreements	1,398,512	964,675	3,139,935	3,282,117
Unrealized loss on interest rate swap agreements	(5,936,928)	(4,756,280)	(244,746)	(4,661,929)
Total gain (loss) on derivatives	$ 171,208,895	$ 40,532,495	$ 44,746,853	$ (251,911,939)

CVR is subject to price fluctuations caused by supply conditions, weather, economic conditions, and other factors and to interest rate fluctuations. To manage price risk on crude oil and other inventories and to fix margins on certain future production, CVR may enter into various derivative transactions. In addition, CALLC, as further described below, entered into certain commodity derivate contracts and an interest rate swap as required by the long-term debt agreements.

CVR has adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, (SFAS 133). SFAS 133 imposes 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, certain over-the-counter forward swap agreements, and interest rate swap agreements, which it believes provide an economic hedge on future transactions, but such instruments are not designated as hedges. Gains or losses related to the change in fair value and periodic settlements of these derivative instruments are classified as loss on derivatives.

At September 30, 2007, CVR s Petroleum Segment held commodity derivative contracts (swap agreements) for the period from July 1, 2005 to June 30, 2010 with a related party (see Note 14, Related Party Transactions). The swap agreements were originally executed by CALLC on June 16, 2005 and were required under the terms of the Company s long-term debt agreements. The notional quantities on the date of execution were 100,911,000 barrels of crude oil; 1,889,459,250 gallons of heating oil and 2,348,802,750 gallons of unleaded gasoline. The swap agreements were executed at the prevailing market rate at the time of execution and management believes the swap agreements provide an economic hedge on future transactions. At September 30, 2007 the notional open amounts under the swap agreements were 48,496,750 barrels of crude oil, 1,018,431,750 gallons of heating oil and 1,018,431,750 gallons of unleaded gasoline. These positions resulted in unrealized gains (losses) for the three and nine month periods ended September 30, 2007 of $90,196,226 and $(98,294,206), respectively, using a valuation method that utilizes quoted market prices and assumptions for the estimated forward yield curves of the related commodities in periods when quoted market prices are unavailable. Unrealized gains were recorded for the three and nine month periods ended September 30, 2006 of $178,545,946 and $80,322,487. The Petroleum Segment recorded $(45,351,557) and $(142,566,824) in realized gains (losses) on these swap agreements for the three and nine month periods ended September 30, 2007, respectively. Realized gains (losses) for the three and nine months ended September 30, 2006 were recorded of $(12,735,079) and $(46,147,786), respectively.

The Petroleum Segment also recorded mark-to-market net gains (losses), exclusive of the swap agreements described above and the interest rate swaps described in the following paragraph, in gain (loss) on derivatives of $(520,569), and $(9,671,097), for the three and nine month periods ended September 30, 2007, respectively and $9,936,444 and $7,676,963 for the three and nine month periods ended September 30, 2006, respectively. All of the activity related to the commodity derivative contracts is reported in the Petroleum Segment.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At September 30, 2007, CRLLC held derivative contracts known as interest rate swap agreements that converted CRLLC s floating-rate bank debt into 4.195% fixed-rate debt on a notional amount of $325,000,000. Half of the agreements are held with a related party (as described in Note 14, Related Party Transactions), and the other half are held with a financial institution that is a lender under CRLLC s long-term debt agreements. The swap agreements carry the following terms:

Period Covered	Notional Amount	Fixed Interest Rate
June 29, 2007 to March 30, 2008	325 million	4.195%
March 31, 2008 to March 30, 2009	250 million	4.195%
March 31, 2009 to March 30, 2010	180 million	4.195%
March 31, 2010 to June 29, 2010	110 million	4.195%

CVR pays the fixed rates listed above and receives a floating rate based on three-month LIBOR rates, with payments calculated on the notional amounts listed above. The notional amounts do not represent actual amounts exchanged by the parties but instead represent the amounts on which the contracts are based. The swap is settled quarterly and marked to market at each reporting date, and all unrealized gains and losses are currently recognized in income. Transactions related to the interest rate swap agreements were not allocated to the Petroleum or Nitrogen Fertilizer segments. Mark-to-market net gains (losses) on derivatives and quarterly settlements were $(3,791,605) and $(1,379,812) for the three and nine month periods ended September 30, 2007, respectively. Mark-to-market net gains (losses) on derivatives and quarterly settlements were $(4,538,416) and $2,895,189 for the three and nine month periods ended September 30, 2006, respectively.

(14) Related Party Transactions

GS Capital Partners V Fund, L.P. and related entities (GS) and Kelso Investment Associates VII, L.P. and related entity (Kelso) were majority owners of CALLC as of September 30, 2007.

On June 24, 2005, CALLC entered into management services agreements with each of GS and Kelso pursuant to which GS and Kelso agreed to provide CALLC with managerial and advisory services. In consideration for these services, an annual fee of $1.0 million each was paid to GS and Kelso, plus reimbursement for any out-of-pocket expenses. The agreements had a term ending on the date GS and Kelso ceased to own any interests in CALLC. Relating to the agreements, $500,000 and $1,581,849 was expensed in selling, general, and administrative expenses (exclusive of depreciation and amortization) for the three and nine months ended September 30, and 2007, respectively. $518,264 and $1,566,891 were expensed in selling, general, and administrative expense (exclusive of depreciation and amortization) for the three and nine months ended September 30, 2006. The agreements terminated upon consummation of CVR s initial public offering on October 26, 2007. The Company paid a one-time fee of $5 million to each of GS and Kelso by reason of such termination on October 26, 2007.

CALLC entered into certain crude oil, heating oil, and gasoline swap agreements with a subsidiary of GS. Additional swap agreements with this subsidiary of GS were entered into on June 16, 2005, with an expiration date of June 30, 2010 (as described in Note 13, Derivative Financial Instruments). Amounts totaling $44,844,669 and $(240,861,030) were recognized related to these swap agreements for the three and nine months ended September 30, 2007, respectively, and are reflected in gain (loss) on derivatives. Amounts totaling $165,810,867 and $34,174,701 were recognized for the three and nine months ended September 30, 2006, respectively. In addition, the consolidated balance sheet at December 31, 2006 and September 30, 2007 includes liabilities of $36,894,802 and $241,427,327 included in current payable to swap counterparty and $72,806,486 and $99,202,285 included in long-term payable to swap counterparty.

On June 26, 2007, the Company entered into a letter agreement with the subsidiary of GS to defer a $45.0 million payment owed on July 8, 2007 to the GS subsidiary for the period ended September 30, 2007 until August 7, 2007. Interest accrued on the deferred amount of $45.0 million at the rate of LIBOR plus 3.25%.

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As a result of the flood and the related temporary cessation of business operations, the Company entered into a subsequent letter agreement on July 11, 2007 in which the GS subsidiary agreed to defer an additional $43.7 million of the balance owed for the period ending June 30, 2007. This deferral was entered into on the conditions that each of GS and Kelso each agreed to guarantee one half of the payment and that interest accrued on the $43.7 million from July 9, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On July 26, 2007, the Company entered into a letter agreement in which the GS subsidiary agreed to defer to September 7, 2007 both the $45.0 million payment due August 7, 2007 along with accrued interest and the $43.7 million payment due July 25, 2007 with the related accrued interest. These payments were deferred on the conditions that GS and Kelso each agreed to guarantee one half of the payments. Additionally, interest accrues on the amount from July 26, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On August 23, 2007, the Company entered into an additional letter agreement in which the GS subsidiary agreed to further defer both deferred payment amounts and the related accrued interest with payment being due on January 31, 2008. Additionally, it was further agreed that the $35 million payment to settle hedged volumes through August 15, 2007 would be deferred with payment being due on January 31, 2008. Interest accrues on all deferral amounts through the payment due date at LIBOR plus 1.50%. GS and Kelso have each agreed to guarantee one half of all payment deferrals. The GS Subsidiary further agreed to defer these payment amounts to August 31, 2008 if the Company closed an initial public offering prior to January 31, 2008. Due to the consummation of the initial public offering on October 26, 2007, these payment amounts are now deferred until August 31, 2008; however, the company is required to use 37.5% of its consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferral amounts.

These deferred payment amounts are included in the consolidated balance sheet at September 30, 2007 in current payable to swap counterparty. Interest relating to the deferred payment amounts reflected in interest expense for the three and nine month periods ended September 30, 2007 was $1,505,950 and $1,505,950, respectively. $1,505,950 is also included in other current liabilities at September 30, 2007.

On August 23, 2007, the Company entered into three new credit facilities, consisting of a $25 million secured facility, a $25 million unsecured facility and a $75 million unsecured facility. A subsidiary of GS was the sole lead arranger and sole bookrunner for each of these new credit facilities. These credit facilities and their arrangements are more fully described in Note 9, Long-Term Debt . The Company paid the subsidiary of GS a $1.3 million fee included in deferred financing costs. For both the three and nine month periods ended September 30, 2007, interest expenses relating to these agreements were $567,209. This amount is included in other current liabilities at September 30, 2007. The secured and unsecured facilities were paid in full on October 26, 2007 with proceeds from CVR s initial public offering, see Note 1, Organization, Initial Public Offering, and Basis of Presentation , and both facilities terminated. Additionally, in connection with the consummation of the initial public offering, the $75 million unsecured facility also terminated.

On June 30, 2005, CALLC entered into three interest-rate swap agreements with the same subsidiary of GS (as described in Note 13, Derivative Financial Instruments). Gains (losses) totaling $(1,893,613) and $(682,869) were recognized related to these swap agreements for the three and nine months ended September 30, 2007, respectively, and are reflected in gain (loss) on derivatives. Gains (losses) totaling $(2,280,293) and $1,441,526 were recognized related to these swap agreements for the three and nine months ended September 30, 2006, respectively. In addition, the consolidated balance sheet at December 31, 2006 and September 30, 2007 includes $1,533,738 and $443,477 in prepaid expenses and other current assets and $2,014,504 and $776,084 in other long-term assets related to the same agreements, respectively.

Effective December 30, 2005, the Company entered into a crude oil supply agreement with a subsidiary of GS (Supplier). This agreement replaced a similar contract held with an independent party. Both parties will negotiate the cost of each barrel of crude oil to be purchased from a third party. CVR will pay Supplier a fixed supply service fee per barrel over the negotiated cost of each barrel of crude purchased. The cost is adjusted further using a spread

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

adjustment calculation based on the time period the crude oil is estimated to be delivered to the refinery, other market conditions, and other factors deemed appropriate. The monthly spread quantity for any delivery month at any time shall not exceed approximately 3.1 million barrels. The initial term of the agreement was to December 31, 2006. CVR and Supplier agreed to extend the term of the Supply Agreement for an additional 12 month period, January 1, 2006 through December 31, 2007 and in connection with the extension amended certain terms and conditions of the Supply Agreement. $1,622,824 and $912,091 were recorded on the consolidated balance sheet at December 31, 2006 and September 30, 2007, respectively, in prepaid expenses and other current assets for prepayment of crude oil. In addition, $31,750,784 and $41,644,294 were recorded in inventory and $13,458,977 and $24,995,809 were recorded in accounts payable at December 31, 2006 and September 30, 2007, respectively. Expenses associated with this agreement, included in cost of product sold (exclusive of depreciation and amortization) for the three and nine month periods ended September 30, 2007 totaled $249,657,118 and $765,799,978, respectively. Expenses associated with this agreement, in cost of product sold (exclusive of depreciation and amortization) for the three and nine month periods ended September 30, 2006 were $444,871,411 and $1,230,270,562, respectively. Interest expense associated with this agreement for the three and nine month periods ended September 30, 2007 totaled $57,148 and $(865,265), respectively.

On October 24, 2007, CVR paid a cash dividend, see Note 16, Dividends , to its shareholders, including approximately $5.23 million that was ultimately distributed from CALLC II (Goldman Sachs Funds) and approximately $5.15 million distributed from CALLC to the Kelso Funds. Management collectively received approximately $0.13 million.

(15) Business Segments

CVR measures segment profit as operating income for Petroleum and Nitrogen Fertilizer, CVR s two reporting segments, based on the definitions provided in SFAS No. 131, *Disclosures About Segments of an Enterprise and Related Information*.

Petroleum

Principal products of the Petroleum Segment are refined fuels, propane, and petroleum refining by-products including coke. CVR uses the coke in the manufacture of nitrogen fertilizer at the adjacent nitrogen fertilizer plant. For CVR, a $15-per-ton transfer price is used to record intercompany sales on the part of the Petroleum Segment and corresponding intercompany cost of product sold (exclusive of depreciation and amortization) for the Nitrogen Fertilizer Segment. The intercompany transactions are eliminated in the Other Segment. Intercompany sales included in Petroleum net sales were $679,785 and $2,560,380 for the three and nine month periods ended September 30, 2007, respectively. Intercompany sales included in petroleum net sales were $1,233,255 and $3,961,995 for the three and nine month periods ended September 30, 2006.

Nitrogen Fertilizer

The principal products of the Nitrogen Fertilizer Segment are anhydrous ammonia and urea ammonia nitrate solution (UAN). Intercompany cost of product sold (exclusive of depreciation and amortization) for the coke transfer described above was $630,836, and $2,596,814 for the three and nine month periods ended September 30, 2007, respectively. Intercompany cost of product sold (exclusive of depreciation and amortization) for the coke transfer was $1,134,167 and $3,804,870 for the three and nine month periods ended September 30, 2006.

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.

Table of Contents

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Net sales				
Petroleum	$ 747,296,328	$ 545,901,618	$ 2,204,959,676	$ 1,707,343,835
Nitrogen Fertilizer	32,523,169	40,755,925	128,155,190	115,090,215
Other				
Intersegment eliminations	(1,233,255)	(679,785)	(3,961,995)	(2,560,380)
Total	$ 778,586,242	$ 585,977,758	$ 2,329,152,871	$ 1,819,873,670
Cost of product sold (exclusive of depreciation and amortization)				
Petroleum	$ 637,506,751	$ 443,081,267	$ 1,828,052,007	$ 1,312,150,415
Nitrogen Fertilizer	8,254,768	3,719,172	23,829,421	9,909,326
Other			(1)	
Intersegment eliminations	(1,134,167)	(630,836)	(3,804,870)	(2,596,815)
Total	$ 644,627,352	$ 446,169,603	$ 1,848,076,557	$ 1,319,462,926
Direct operating expenses (exclusive of depreciation and amortization)				
Petroleum	$ 38,172,132	$ 29,544,102	$ $97,254,100	$ 170,684,235
Nitrogen Fertilizer	18,523,385	14,896,102	47,207,127	48,122,053
Other				
Total	$ 56,695,517	$ 44,440,204	$ 144,461,227	$ 218,806,288
Net costs associated with flood				
Petroleum	$	$ 28,595,169	$	$ 30,629,922
Nitrogen Fertilizer		1,891,736		1,995,925
Other		1,705,437		1,705,437
Total	$	$ 32,192,342	$	$ 34,331,284
Depreciation and amortization				
Petroleum	$ 7,949,815	$ 6,616,389	$ 23,561,843	$ 29,695,304
Nitrogen Fertilizer	4,330,102	3,585,748	12,714,478	12,377,096
Other	507,619	278,928	533,323	601,123
Total	$ 12,787,536	$ 10,481,065	$ 36,809,644	$ 42,673,523

Operating income (loss)				
Petroleum	$ 55,498,485	$ 26,487,906	$ 233,522,252	$ 129,357,929
Nitrogen Fertilizer	(3,007,016)	13,833,936	34,058,010	34,863,022
Other	(342,575)	(1,662,063)	(571,233)	(1,743,360)
Total	$ 52,148,894	$ 38,659,779	$ 267,009,029	$ 162,477,591
Capital expenditures				
Petroleum			$ 157,606,403	$ 235,862,328
Nitrogen Fertilizer			12,710,765	3,597,482
Other			2,633,223	235,072
Total			$ 172,950,391	$ 239,694,882

Table of Contents

CVR ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2006	Nine Months Ended September 30, 2007
Total assets		
Petroleum	$ 907,314,951	$ 1,209,530,905
Nitrogen Fertilizer	417,657,093	414,245,628
Other	124,507,471	224,791,234
Total	$ 1,449,479,515	$ 1,848,567,767
Goodwill		
Petroleum	$ 42,806,422	$ 42,806,422
Nitrogen Fertilizer	40,968,463	40,968,463
Other		
Total	$ 83,774,885	$ 83,774,885

(16) Dividend

CVR declared a cash dividend of $0.168 per share on its common stock to shareholders of record on October 16, 2007. The total cash required for the dividend declared was $10.6 million.

(17) Subsequent Event

During the fourth quarter of 2007, a subsidiary of the Company, CRRM, entered into an agreement for additional crude oil storage and terminalling services with a counterparty beginning January 1, 2008 and ending on December 31, 2014. Average monthly commitments under this agreement for the first nine months will approximate $124,000 with the average monthly commitments for the remaining term increasing to approximately $250,000. This increase results from increased storage capacity beginning on October 1, 2008 and is subject to potential rate acceleration. In conjunction with this agreement, the Company s subsidiary also extended the term of its current crude oil storage and terminalling agreement with the same counterparty to December 31, 2014.

Table of Contents

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

You should read the following discussion and analysis of our financial condition and results of operations in conjunction with our financial statements and related notes included elsewhere in this report.

Forward-Looking Statements

This Form 10-Q, including this management s discussion and analysis, contains forward-looking statements as defined by the Securities and Exchange Commission (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, 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 that 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 and contained elsewhere in this Report.

All forward-looking statements contained in this Form 10-Q only speak 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

We are an independent refiner and marketer of high value transportation fuels and a producer of ammonia and UAN fertilizers.

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

The nitrogen fertilizer segment consists of our interest in CVR Partners, LP, a limited partnership controlled by our affiliates, which operates a nitrogen fertilizer plant and the nitrogen fertilizer business. The nitrogen fertilizer business is the lowest cost producer of ammonia and UAN in North America, assuming natural gas prices remain at current levels. The fertilizer plant is the only commercial facility in North America utilizing a coke gasification process to produce nitrogen fertilizers. Its redundant train gasifier provides exceptional on-stream reliability and the use of low cost by-product pet coke feed from the adjacent oil refinery as feedstock (rather than natural gas) to produce hydrogen provides the facility with a significant competitive advantage compared to high and volatile natural gas prices. The plant s competition utilizes natural gas to produce ammonia.

Initial Public Offering

On October 26, 2007 we completed an initial public offering of 23,000,000 shares of our common stock. The initial public offering price was $19.00 per share. The net proceeds to us from the sale of our common stock were approximately $408.5 million, after deducting underwriting discounts and commissions. We also incurred approximately $11.4 million of other costs related to the initial public offering.

The net proceeds from the offering were used to repay $280 million of CVR s outstanding term loan debt and to repay in full the $25 million secured credit facility and the $25 million unsecured credit facility. We also repaid $50 million of indebtedness under our revolving credit facility. Associated with the repayment of the $25 million secured facility and the $25 million unsecured facility, we expect to record a write-off of unamortized deferred financing fees of approximately $1.3 million in the fourth quarter of 2007.

In connection with the initial public offering, we also became the indirect owner of Coffeyville Resources, LLC and all of its refinery assets. This was accomplished by CVR issuing 62,866,720 shares of its common stock to certain entities controlled by its majority stockholder in exchange for the interests in certain subsidiaries of CALLC. Immediately following the completion of the offering, there were 86,141,291 shares of common stock outstanding, excluding any restricted shares issued.

Major Influences on Results of Operations

Petroleum Business. Our earnings and cash flows from our petroleum operations are primarily affected by the relationship between refined product prices and the prices for crude oil and other feedstocks. Feedstocks are petroleum products, such as crude oil and natural gas liquids, that are processed and blended into refined products. The cost to acquire feedstocks and the price for which refined products are ultimately sold depend on factors beyond our control, including the supply of, and demand for, crude oil, as well as gasoline and other refined products which, in turn, depend on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and the extent of government regulation. Because we apply first-in, first-out, or FIFO, accounting to value our inventory, crude oil price movements may impact net income in the short term because of instantaneous changes in the value of the minimally required, unhedged on hand inventory. The effect of changes in crude oil prices on our results of operations is influenced by the rate at which the prices of refined products adjust to reflect these changes.

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

In order to assess our operating performance, we compare our net sales, less cost of product sold (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 (WTI) crude oil (West Texas Intermediate crude oil, which is used as a benchmark for other crude oils), we refer to the benchmark as the NYMEX 2-1-1 crack spread, or simply, the 2-1-1 crack spread. The 2-1-1 crack spread is expressed in dollars per barrel and is a proxy for the per barrel margin that a sweet crude refinery would earn assuming it produced and sold the benchmark production of gasoline and distillate.

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

We produce a high volume of high value products, such as gasoline and distillates. We benefit from the fact that our marketing region consumes more refined products than it produces so that the market prices of our products have to be high enough to cover the logistics cost for the U.S. Gulf Coast refineries to ship into our region. The result of this logistical advantage and the fact the actual product specification used to determine the NYMEX is different from the actual production in the refinery is that prices we realize are different than those used in determining the 2-1-1 crack spread. The difference between our price and the price used to calculate the 2-1-1 crack spread is referred to as gasoline PADD II, Group 3 vs. NYMEX basis, or gasoline basis, and heating oil PADD II, Group 3 vs. NYMEX basis, or heating oil basis.

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.

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.

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

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

The value of nitrogen fertilizer products is also an important consideration in understanding our results. The nitrogen fertilizer business generally upgrades approximately two-thirds of its ammonia production into UAN, a product that presently generates a greater value than ammonia. UAN production is a major contributor to our profitability. In order to assess the value of nitrogen fertilizer products, we calculate netbacks, also referred to as plant gate price. Netbacks refer to the unit price of fertilizer, in dollars per ton, offered on a delivered basis, excluding shipment costs.

The direct operating expense structure of the nitrogen fertilizer business is also important to its profitability. Using a pet coke gasification process, the nitrogen fertilizer business has significantly higher fixed costs than natural gas-based fertilizer plants. Major direct operating expenses include electrical energy, employee labor, maintenance, including contract labor, and outside services. These costs comprise the fixed costs associated with the fertilizer plant.

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.

2007 Flood and Crude Oil Discharge

During the weekend of June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville, Kansas. Our refinery and the nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded, sustained major damage and required extensive repairs. Total costs incurred and recorded as of September 30, 2007 related to the third party costs to repair the refinery and fertilizer facilities were approximately $71.4 million and $3.1 million, respectively. The total third party cost to repair the refinery is currently estimated at approximately $86 million, and the total third party cost to repair the nitrogen fertilizer facility is currently estimated at approximately $4 million.

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

In addition, despite our efforts to secure the refinery prior to its evacuation as a result of the flood, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007. We are currently remediating the contamination caused by the crude oil discharge. Total net costs recorded as of September 30, 2007 associated with remediation efforts and third party property damage incurred by the crude oil discharge are approximately $18.1 million. This amount is net of anticipated insurance recoveries of $21.4 million. Subsequent to September 30, 2007, we received $10 million of insurance proceeds under our environmental insurance policy.

Our results for the nine months ended September 30, 2007 include pretax costs of $34.3 million associated with the flood and related crude oil discharge. This amount is net of anticipated insurance recoveries of $96.4 million. We anticipate that approximately $15.5 million in third party costs related to the repair of the flood damaged property will be recorded in future periods.

The flood and crude oil discharge had a significant adverse impact on our third quarter financial results. We reported reduced revenue due to the closure of our facilities for a portion of the third quarter, as well as significant costs related to the flood as a result of the necessary repairs to our facilities and environmental remediation.

Refinancing and Prior Indebtedness

On December 28, 2006, we entered into a new credit facility and used the proceeds thereof to repay our then existing first lien credit facility and second lien credit facility, and to pay a dividend to the members of Coffeyville

Table of Contents

Acquisition LLC. The credit facility provides financing of up to $1.075 billion, consisting of $775 million of tranche D term loans, a $150 million revolving credit facility, and a funded letter of credit facility of $150 million issued in support of the Cash Flow Swap. The credit facility is secured by substantially all of Coffeyville Resources, LLC s assets. As a result, interest expense related to the term debt outstanding of $771.1 million for the nine months ended September 30, 2007 was significantly higher than interest expense on term debt outstanding of $527.8 million at September 30, 2006. Consolidated interest expense for the nine months ended September 30, 2007 was $46.0 million as compared to interest expense of $33.0 million for the nine months ended September 30, 2006.

The flood and crude oil discharge had a significant negative effect on our liquidity in July/August 2007. As a result of this, in August 2007, our subsidiaries entered into a $25 million secured facility, a $25 million unsecured facility and a $75 million unsecured facility. No amounts were drawn under the $75 million unsecured facility. Our statement of operations for the nine months ended September 30, 2007 includes $1.1 million in interest expense related to these facilities with no comparable amount for the same period in the prior year.

In October 2007, we paid down $280 million of term debt with initial public offering proceeds. Additionally, we repaid the $25 million secured facility and $25 million unsecured facility in their entirety with a portion of the net proceeds from the initial public offering. Also, the $75 million credit facility terminated upon consummation of the initial public offering.

J. Aron Deferrals

As a result of the flood and the temporary cessation of our operations on June 30, 2007, Coffeyville Resources, LLC entered into several deferral agreements with J. Aron & Company (J. Aron) with respect to the Cash Flow Swap, which is a series of commodity derivative arrangements whereby if crack spreads fall below a fixed level, J. Aron agreed to pay the difference to us, and if crack spreads rise above a fixed level, we agreed to pay the difference to J. Aron. These deferral agreements deferred to January 31, 2008 the payment of approximately $123.7 million (plus accrued interest) which we owed to J. Aron. J. Aron has agreed to further defer these payments to August 31, 2008 but we will be required to use 37.5% of our consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferred amounts.

Change in Reporting Entity as a Result of the Initial Public Offering

Prior to our initial public offering in October 2007, our operations were conducted by an operating partnership, Coffeyville Resources, LLC. The reporting entity of the organization was also a partnership. Immediately prior to the closing of our initial public offering, Coffeyville Resources, LLC became an indirect, wholly-owned subsidiary of CVR Energy, Inc. as a result of a series of steps. As a result, in the future, we will report our results of operations and financial condition as a corporation on a consolidated basis rather than as an operating partnership.

Public Company Expenses

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

2007 Turnaround

In April 2007, we completed a planned turnaround of our refining plant at a total cost approximating $81 million. The majority of these costs were expensed in the first quarter of 2007. The refinery processed crude until February 11, 2007 at which time a staged shutdown of the refinery began. The refinery recommenced operations on March 22, 2007 and continually increased crude oil charge rates until all of the key units were restarted by April 23, 2007. The turnaround significantly impacted our financial results for 2007, but had very little impact on our 2006 results.

Table of Contents

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 nine months ended September 30, 2006 and 2007. The summary financial data for our two operating segments does not include certain SG&A expenses and depreciation and amortization related to our corporate offices. The following data should be read in conjunction with our condensed consolidated financial statements and the notes thereto included elsewhere in this Form 10-Q. All information in Management s Discussion and Analysis of Financial Condition and Results of Operations , except for the balance sheet data as of December 31, 2006, is unaudited.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
	(In millions, except as otherwise indicated)			
Consolidated Statement of Operations Data:				
Net sales	$ 778.6	$ 586.0	$ 2,329.2	$ 1,819.9
Cost of product sold (exclusive of depreciation and amortization)	644.7	446.2	1,848.1	1,319.5
Direct operating expense (exclusive of depreciation and amortization)	56.7	44.4	144.5	218.8
Selling, general and administrative expense (exclusive of depreciation and amortization)	12.3	14.0	32.8	42.1
Net costs associated with flood(1)		32.2		34.3
Depreciation and amortization(2)(3)	12.8	10.5	36.8	42.7
Operating income	$ 52.1	$ 38.7	$ 267.0	$ 162.5
Other income (expense)	1.7	0.2	3.1	0.9
Interest (expense)	(10.7)	(18.3)	(33.0)	(46.0)
Gain (loss) on derivatives	171.2	40.5	44.7	(251.9)
Income (loss) before income taxes and minority interest in subsidiaries	$ 214.3	$ 61.1	$ 281.8	$ (134.5)
Income tax (expense) benefit	(85.3)	(47.6)	(111.0)	93.4
Minority interest in (income) loss of subsidiaries		(0.1)		0.2
Net income (loss)(4)	$ 129.0	$ 13.4	$ 170.8	$ (40.9)
Pro forma earnings per share, basic	$ 1.50	$ 0.16	$ 1.98	$ (0.47)
Pro forma earnings per share, diluted	$ 1.50	$ 0.16	$ 1.98	$ (0.47)
Pro forma weighted average shares, basic	86,141,291	86,141,291	86,141,291	86,141,291
Pro forma weighted average shares, diluted	86,158,791	86,158,791	86,158,791	86,141,291
Balance Sheet Data:				
Cash and cash equivalents			$ 38.1	$ 27.3
Working capital			173.4	(27.0)
Total assets			1,397.7	1,848.6
Total debt, including current portion			527.8	847.0

Minority interest in subsidiaries				5.2
Management units subject to compromise			9.0	8.7
Members equity			303.1	34.5
Stockholders equity				
Other Financial Data:				
Depreciation and amortization(3)	$ 12.8	$ 10.5	$ 36.8	$ 42.7
Net Income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(5)	21.7	(40.8)	122.5	18.2
Cash flows (used in) provided by operating activities	(22.4)	3.9	97.9	161.5
Cash flows (used in) investing activities	(86.8)	(25.6)	(173.0)	(239.7)
Cash flows provided by financing activities	19.4	26.0	48.5	63.6
Capital expenditures for property, plant and equipment	86.8	25.6	173.0	239.7

Table of Contents

	Three Months Ended September 30, 2006	2007	Nine Months Ended September 30, 2006	2007
Key Operating Statistics:				
Petroleum Business				
Production (barrels per day)(6)	107,094	58,382	106,975	71,454
Crude oil throughput (barrels per day)(6)	94,019	52,497	94,061	64,829
Nitrogen Fertilizer Business				
Production Volume:				
Ammonia (tons in thousands)	78.3	75.9	283.9	244.9
UAN (tons in thousands)	136.7	128.0	465.0	432.6

(1) Represents the write-off of approximate net costs associated with the flood and oil spill that are not probable of recovery.

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

	Three Months Ended September 30, 2006	2007	Nine Months Ended September 30, 2006	2007
	(Unaudited) (In millions)			
Depreciation and amortization included in cost of product sold	$ 0.5	$ 0.6	$ 1.6	$ 1.8
Depreciation and amortization included in direct operating expense	11.7	9.6	34.5	40.2
Depreciation and amortization included in selling, general and administrative expense	0.6	0.3	0.7	0.7
Total depreciation and amortization	$ 12.8	$ 10.5	$ 36.8	$ 42.7

(3) Depreciation and amortization does not include approximately $7.6 million for both the three and nine months ended September 30, 2007 which is included in net costs associated with flood due to the facilities being temporarily idled.

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

	Three Months Ended September 30, 2006	2007	Nine Months Ended September 30, 2006	2007

	(Unaudited) (In millions)			
Funded letter of credit expense and interest rate swap not included in interest expense(a)	$ (0.4)	$ 0.7	$ 0.2	$ 0.9
Major scheduled turnaround expense(b)	4.1		4.4	76.8
Unrealized (gain) loss from Cash Flow Swap	(178.5)	(90.2)	(80.3)	98.3

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

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

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

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007

Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap	$ 21.7	$ (40.8)	$ 122.5	$ 18.2
Plus:				
Unrealized gain (loss) from Cash Flow Swap, net of taxes	107.3	54.2	48.3	(59.1)
Net income (loss)	$ 129.0	$ 13.4	$ 170.8	$ (40.9)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
	(Unaudited) (In millions, except as otherwise indicated)			
Petroleum Business:				
Net sales	$ 747.3	$ 545.9	$ 2,205.0	$ 1,707.3
Cost of product sold (exclusive of depreciation and amortization)	637.5	443.1	1,828.1	1,312.2
Direct operating expense (exclusive of depreciation and amortization)	38.2	29.5	97.3	170.7
Net costs associated with flood		28.6		30.6
Depreciation and amortization	7.9	6.6	23.6	29.7
Gross profit	$ 63.7	$ 38.1	$ 256.0	$ 164.1
Plus direct operating expense (exclusive of depreciation and amortization)	38.2	29.5	97.3	170.7
Plus Net costs associated with flood		28.6		30.6
Plus depreciation and amortization	7.9	6.6	23.6	29.7
Refining margin(1)	$ 109.8	$ 102.8	$ 376.9	$ 395.1
Refining margin per crude oil throughput barrel	$ 12.69	$ 21.28	$ 14.68	$ 22.32
Gross profit per crude oil throughput barrel	$ 7.36	$ 7.89	$ 9.97	$ 9.27
Direct operating expense (exclusive of depreciation and amortization) per crude oil throughput barrel	$ 4.42	$ 6.11	$ 3.79	$ 9.64
Operating income (loss)	55.5	26.5	233.5	129.4

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

Table of Contents

Market Indicators	Three Months Ended September 30, 2006	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
	(Dollars per barrel)			
West Texas Intermediate (WTI) crude oil	$ 70.54	$ 75.15	$ 68.26	$ 66.19
NYMEX 2-1-1 Crack Spread	10.85	12.12	11.63	15.45
Crude Oil Differentials:				
WTI less WTS (sour)	4.54	5.30	5.43	4.69
WTI less Maya (heavy sour)	14.89	12.34	15.55	11.56
WTI less Dated Brent (foreign)	0.99	0.52	1.33	0.89
PADD II Group 3 versus NYMEX Basis:				
Gasoline	4.00	8.93	1.82	4.74
Heating Oil	12.49	9.97	7.90	9.54

Company Operating Statistics	Three Months Ended September 30, 2006	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
	(Dollars per barrel)			
Per barrel profit, margin and expense of crude oil throughput:				
Refining margin	12.69	21.28	14.68	22.32
Gross profit	7.36	7.89	9.97	9.27
Direct operating expense (exclusive of depreciation and amortization)	4.42	6.11	3.79	9.64
Per gallon sales price:				
Gasoline	2.11	2.28	1.99	2.14
Distillate	2.20	2.35	2.04	2.12

Selected Company Volumetric Data	Three Months Ended September 30, 2006 Barrels Per Day	%	Three Months Ended September 30, 2007 Barrels Per Day	%	Nine Months Ended September 30, 2006 Barrels Per Day	%	Nine Months Ended September 30, 2007 Barrels Per Day	%
Production:								
Total gasoline	41,980	39.2	25,971	44.4	46,137	43.1	29,949	41.9
Total distillate	39,682	37.1	23,448	40.2	41,401	38.7	29,511	41.3
Total other	25,432	23.7	8,963	15.4	19,437	18.2	11,994	16.8
Total all production	107,094	100.0	58,382	100.0	106,975	100.0	71,454	100.0
Crude oil throughput	94,019	92.3	52,497	93.9	94,061	92.6	64,829	94.7
All other inputs	7,831	7.7	3,403	6.1	7,463	7.4	3,643	5.3

Total feedstocks	101,850	100.0	55,900	100.0	101,524	100.0	68,472	100.0

Table of Contents

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006		2007		2006		2007	
	Total Barrels	%	Total Barrels	%	Total Barrels	%	Total Barrels	%
Crude oil throughput by crude type:								
Sweet	5,466,637	63.2	2,835,032	58.7	12,916,402	50.3	11,203,099	63.3
Light/medium sour	3,105,258	35.9	1,168,786	24.2	12,685,293	49.4	5,256,430	29.7
Heavy sour	77,848	0.9	825,878	17.1	77,036	0.3	1,238,889	7.0
Total crude oil throughput	8,649,743	100.0	4,829,696	100.0	25,678,731	100.0	17,698,418	100.0

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
	(Unaudited) (In millions, except as otherwise indicated)			
Nitrogen Fertilizer Business:				
Net sales	$ 32.5	$ 40.8	$ 128.2	$ 115.1
Cost of product sold (exclusive of depreciation and amortization)	8.3	3.7	23.8	9.9
Direct operating expense (exclusive of depreciation and amortization)	18.5	14.9	47.2	48.1
Net costs associated with flood		1.9		2.0
Depreciation and amortization	4.3	3.6	12.7	12.4
Operating income (loss)	(3.0)	13.8	34.1	34.9

Market Indicators	Three Months Ended September 30, 2006	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
Natural gas (dollars per million BTU)	$ 6.18	$ 6.24	$ 6.89	$ 7.02
Ammonia southern plains (dollars per ton)	311	390	362	393
UAN corn belt (dollars per ton)	183	298	199	277

Table of Contents

Company Operating Statistics	Three Months Ended September 30, 2006	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
Production (thousand tons):				
Ammonia	78.3	75.9	283.9	244.9
UAN	136.7	128.0	465.0	432.6
Total	215.0	203.9	748.9	677.5
Sales (thousand tons)(1):				
Ammonia	30.6	24.7	96.8	58.8
UAN	138.4	120.6	477.7	414.2
Total	169.0	145.3	574.5	473.0
Product pricing (plant gate) (dollars per ton)(1):				
Ammonia	$ 283	$ 363	$ 346	$ 358
UAN	141	234	169	203
On-stream factor(2):				
Gasification	80.7%	81.3%	91.7%	87.4%
Ammonia	74.2%	80.4%	87.8%	84.6%
UAN	76.2%	71.8%	87.9%	78.5%
Reconciliation to net sales (dollars in thousands):				
Freight in revenue	$ 4,420	$ 3,581	$ 13,860	$ 10,011
Sales net plant gate	28,103	37,175	114,295	105,080
Total net sales	32,523	40,756	128,155	115,091

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

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

Three Months Ended September 30, 2007 Compared to the Three Months Ended September 30, 2006

Consolidated

Net Sales. Consolidated net sales were $586.0 million for the three months ended September 30, 2007 compared to $778.6 million for the three months ended September 30, 2006. The decrease of $192.6 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was primarily due to a decrease in petroleum net sales of $201.4 million that resulted from lower sales volumes ($301.5 million), partially offset by higher product prices ($100.1 million). Nitrogen fertilizer net sales increased $8.3 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 due to higher plant gate prices ($15.2 million), offset by lower sales volumes ($6.9 million).

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $446.2 million for the three months ended September 30, 2007 as compared to

$644.6 million for the three months ended September 30, 2006. The decrease of $198.4 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 primarily resulted from a significant reduction in refined fuel production volumes over the comparable periods due to refinery downtime resulting from the flood.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Consolidated direct operating expenses exclusive of depreciation and amortization were $44.4 million for the three months ended September 30, 2007 as compared to $56.7 million for the three months ended September 30, 2006. This decrease of $12.3 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was due to a decrease in petroleum direct operating expenses of $8.7 million, primarily related to decreases in expenses associated with labor, utilities and energy due to the refinery not operating because of the flood and the refinery turnaround, and a decrease in nitrogen fertilizer direct operating expenses of $3.6 million, primarily because of the turnaround expenses incurred in the 2006 period.

Selling, General and Administrative Expenses Exclusive of Depreciation and Amortization. Consolidated selling, general and administrative expenses were $14.0 million for the three months ended September 30, 2007 as compared to $12.3 million for the three months ended September 30, 2006. This variance was primarily the result of increases in administrative labor related to deferred compensation ($3.7 million) and bank charges ($0.6 million) partially offset by reductions in expenses associated with asset retirements ($1.1 million), outside services ($0.9 million), public relations ($0.5 million) and office costs ($0.2 million).

Net Costs Associated with Flood. Consolidated net costs associated with flood for the three months ended September 30, 2007 approximated $32.2 million as compared to none for the three months ended September 30, 2006. Total gross costs recorded for the three months ended September 30, 2007 were approximately $128.6 million. Of these gross costs, approximately $89.1 million were associated with repair and other matters as a result of the damage to the Company s facilities. Included in this cost was $7.6 million of depreciation for the temporarily idled facilities, $5.9 million for internal salaries, $2.9 million of professional fees and $72.7 million for other repair and related costs. There were approximately $39.5 million costs recorded with respect to the environmental remediation and property damage. Total accounts receivable from insurers approximated $96.4 million at September 30, 2007, for which we believe collection is probable.

Depreciation and Amortization. Consolidated depreciation and amortization was $10.5 million for the three months ended September 30, 2007 as compared to $12.8 million for the three months ended September 30, 2006. During the restoration period for both the refinery and the nitrogen fertilizer operations due to the flood, $7.6 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this reclassification, consolidated depreciation and amortization would have increased by approximately $5.3 million for the three months ended September 30, 2007 compared to the three months ended September 30, 2006, primarily as a result of the assets placed into service during the fourth quarter of 2006 and in 2007 resulting from the significant capital projects we have most recently completed.

Operating Income. Consolidated operating income was $38.7 million for the three months ended September 30, 2007 as compared to operating income of $52.1 million for the three months ended September 30, 2006. For the three months ended September 30, 2007 as compared to the three months ended September 30, 2006, petroleum operating income decreased $29.0 million and nitrogen fertilizer operating income increased by $16.8 million.

Interest Expense. Consolidated interest expense for the three months ended September 30, 2007 was $18.3 million as compared to interest expense of $10.7 million for the three months ended September 30, 2006. This 71% increase for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 primarily resulted from an overall increase in the index rates (primarily LIBOR) and an increase in average borrowings outstanding during the comparable periods. Consolidated interest expense over the comparable periods was partially offset by decreases in the applicable margins under our Credit Facility dated December 28, 2006 as compared to the borrowing facility in effect during the nine months ended September 30, 2006.

Interest Income. Interest income was $0.2 million for the three months ended September 30, 2007 as compared to $1.1 million for the three months ended September 30, 2006.

Gain (loss) on Derivatives. We have determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and*

Hedging Activities. For the three months ended September 30, 2007, we incurred $40.5 million in gains on derivatives. This compares to a $171.2 million gain on derivatives for the three months ended September 30, 2006. This significant decrease in gains on derivatives for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was primarily attributable to the realized and unrealized gains (losses) on our Cash Flow Swap. Realized losses on the Cash Flow Swap for the three months ended September 30, 2007 and the three months ended September 30, 2006 were $45.4 million and $12.7 million, respectively. The increase in realized losses over the comparable periods was primarily the result of higher average crack spreads for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006. Unrealized gains or losses represent the change in the mark-to-market value on the unrealized portion of the Cash Flow Swap based on changes in the NYMEX crack spread that is the basis for the Cash Flow Swap. Unrealized gains on our Cash Flow Swap for the three months ended September 30, 2007 and the three months ended September 30, 2006 were $90.2 million and $178.5 million, respectively. These gains reflect decreases in the crack spread values on the unrealized positions comprising the Cash Flow Swap. In addition to the change in the NYMEX crack spread, the outstanding term of the Cash Flow Swap at the end of each period also affects the impact of changes in the underlying crack spread. As of September 30, 2007, the Cash Flow Swap had a remaining term of approximately two years and nine months whereas as of September 30, 2006, the remaining term on the Cash Flow Swap was approximately three years and nine months. As a result of the longer remaining term as of September 30, 2006, a similar change in crack spread will have a greater impact on the unrealized gains or losses.

Provision for Income Taxes. Income tax expense for the three months ended September 30, 2007 was $47.6 million, or 78% of income before income taxes, as compared to income tax expense of $85.3 million, or 40% of earnings before income taxes, for the three months ended September 30, 2006. The annualized effective rate for 2007, which was applied to loss before income taxes for the three month period ended September 30, 2007, is higher than the comparable annualized effective tax rate for 2006, which was applied to earnings before income taxes for the three months ended September 30, 2006, primarily due to the correlation between the amount of credits which are projected to be generated in 2007 from the production of ultra low sulfur diesel fuel and the reduced level of projected earnings before income taxes for 2007.

Minority Interest in (income) loss of Subsidiaries. Minority interest in income of subsidiaries for the three months ended September 30, 2007 was $0.1 million. Minority interest relates to common stock in two of our subsidiaries owned by our chief executive officer. In October 2007, in connection with our initial public offering, our chief executive officer exchanged his common stock in our subsidiaries for common stock of CVR Energy.

Net Income. For the three months ended September 30, 2007, net income decreased to net income of $13.4 million as compared to net income of $129.0 million for the three months ended September 30, 2006. Net income decreased $115.6 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006, primarily due to downtime and costs associated with the flood and a significant change in the value of the Cash Flow Swap over the comparable periods.

Petroleum

Net Sales. Petroleum net sales were $545.9 million for the three months ended September 30, 2007 compared to $747.3 million for the three months ended September 30, 2006. The decrease of $201.4 million from the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was primarily the result of significantly lower sales volumes ($301.5 million), partially offset by higher product prices ($100.1 million). Overall sales volumes of refined fuels for the three months ended September 30, 2007 decreased 39% as compared to the three months ended September 30, 2006. The decreased sales volume primarily resulted from a significant reduction in refined fuel production volumes over the comparable periods due to refinery downtime resulting from the flood. Our average sales price per gallon for the three months ended September 30, 2007 for gasoline of $2.28 and distillate of $2.35 increased by 8% and 7%, respectively, as compared to the three months ended September 30, 2006.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Petroleum cost of product sold exclusive of depreciation and amortization was $443.1 million for the three months ended September 30, 2007 compared to $637.5 million for the three months ended September 30, 2006. The decrease of

$194.4 million from the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was primarily the result of a significant reduction in crude throughput due to downtime resulting from the flood. In addition to the flood, higher crude oil prices, reduced sales volumes and the impact of FIFO accounting also impacted cost of product sold during the comparable periods. Our average cost per barrel of crude oil for the three months ended September 30, 2007 was $70.93, compared to $68.06 for the comparable period of 2006, an increase of 4%. Sales volume of refined fuels decreased 39% for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 principally due to the downtime associated with the flood. In addition, under our FIFO accounting method, changes in crude oil prices can cause fluctuations in the inventory valuation of our crude oil, work in process and finished goods, thereby resulting in FIFO inventory gains when crude oil prices increase and FIFO inventory losses when crude oil prices decrease. For the three months ended September 30, 2007, we had FIFO inventory gains of $18.7 million compared to FIFO inventory losses of $7.1 million for the comparable period of 2006.

Refining margin per barrel of crude throughput increased from $12.69 for the three months ended September 30, 2006 to $21.28 for the three months ended September 30, 2007 primarily due to the 12% increase ($1.27 per barrel) in the average NYMEX 2-1-1 crack spread over the comparable periods and positive regional differences between gasoline prices in our primary marketing region (the Coffeyville supply area) and those of the NYMEX. The average gasoline basis for the three months ended September 30, 2007 increased by $4.93 per barrel to $8.93 per barrel compared to $4.00 per barrel in the comparable period of 2006. The positive basis for gasoline during the comparable periods was partially offset by a decrease in the average distillate basis for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006. The average distillate basis decreased by $2.52 per barrel to $9.97 per barrel compared to $12.49 per barrel in the comparable period of 2006. The positive effect of the increased NYMEX 2-1-1 crack spreads and overall refined fuels basis over the comparable periods was further enhanced by an increase in crude oil differential over the comparable periods. Increased discounts for sour crude oils evidenced by the $0.76 per barrel, or 17%, increase in the spread between the WTI price, which is a market indicator for the price of light sweet crude, and the WTS price, which is an indicator for the price of sour crude, positively impacted refining margin for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance (turnaround), labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $29.5 million for the three months ended September 30, 2007 compared to direct operating expenses of $38.2 million for the three months ended September 30, 2006. The decrease of $8.7 million for the three months ended September 30, 2007 compared to the three months ended September 30, 2006 was the result of decreases in expenses associated with direct labor ($3.2 million), utilities and energy ($2.7 million), refinery turnaround ($1.8 million), rent and lease ($1.7 million), operating materials ($1.4 million), environmental ($0.7 million), repairs and maintenance ($0.7 million), production chemicals ($0.2 million) and outside services ($0.1 million). These decreases in direct operating expenses were partially offset by increases in expenses associated with property taxes ($3.3 million) and insurance ($0.6 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for the three months ended September 30, 2007 increased to $6.11 per barrel as compared to $4.42 per barrel for the three months ended September 30, 2006 principally due to downtime at the refinery due to the flood and the corresponding impact on overall crude oil throughput and production volume.

Net Costs Associated with Flood. Petroleum net costs associated with flood for the three months ended September 30, 2007 approximated $28.6 million as compared to none for the three months ended September 30, 2006. Total gross costs recorded for the three months ended September 30, 2007 were approximately $121.3 million. Of these gross costs approximately $81.8 million were associated with repair and other matters as a result of the damage to the refinery. Included in this cost was approximately $6.8 million recorded for depreciation for the temporarily idle facilities, $4.6 million for internal salaries, $1.8 million of professional fees and $68.6 million for other repair and related costs. There were approximately $39.5 million recorded with respect to the environmental remediation and property damage. Total accounts receivable from insurers approximated $92.7 million at September 30, 2007, for which we believe collection is probable.

Depreciation and Amortization. Petroleum depreciation and amortization was $6.6 million for the three months ended September 30, 2007 as compared $7.9 million for the three months ended September 30, 2006. During the restoration period for the refinery due to the flood, $6.8 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this $6.8 million reclassification, the increase in petroleum depreciation and amortization for the three months ended September 30, 2007 compared to the three months ended September 30, 2006 would have been approximately $5.5 million. This adjusted increase in petroleum depreciation and amortization for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was primarily the result of the completion of the several large capital projects in late 2006 and during the nine months ended September 30, 2007.

Operating Income. Petroleum operating income was $26.5 million for the three months ended September 30, 2007 as compared to operating income of $55.5 million for the three months ended September 30, 2006. This decrease of $29.0 million from the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was primarily the result of the refinery downtime resulting from the flood and the $28.6 million increase in net costs associated with the flood. Substantially all of the refinery s units damaged by the flood were back in operation by August 20, 2007. Offsetting the negative impacts of the flood was an $8.7 million reduction in direct operating expenses for the three months ended September 30, 2007 compared to the three months ended September 30, 2006. This reduction was the result of decreases in expenses associated with direct labor ($3.2 million), utilities and energy ($2.7 million), refinery turnaround ($1.8 million), rent and lease ($1.7 million), operating materials ($1.4 million), environmental ($0.7 million), repairs and maintenance ($0.7 million), production chemicals ($0.2 million) and outside services ($0.1 million). These decreases in direct operating expenses were partially offset by increases in expenses associated with taxes ($3.3 million) and insurance ($0.6 million).

Fertilizer

Net Sales. Nitrogen fertilizer net sales were $40.8 million for the three months ended September 30, 2007 compared to $32.5 million for the three months ended September 30, 2006. The increase of $8.3 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was the result of higher plant gate prices ($15.2 million), offset by reductions in overall sales volume ($6.9 million).

In regard to product sales volumes for the three months ended September 30, 2007, our nitrogen operations experienced a decrease of 19% in ammonia sales unit volumes (5,918 tons) and a decrease of 13% in UAN sales unit volumes (17,835 tons). The decrease in ammonia sales volume was the result of decreased production volumes during the three months ended September 30, 2007 relative to the comparable period of 2006 due to the transfer of hydrogen to our Petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit. The transfer of hydrogen to our Petroleum operations is scheduled to be replaced with hydrogen produced by the new continuous catalytic reformer scheduled to be completed in late 2007 to early 2008. On-stream factors (total number of hours operated divided by total hours in the reporting period) for the gasification and ammonia units were greater than the three months ended September 30, 2006. On-stream factors for the UAN plant were lower than the three month period ended September 30, 2006. During the three months ended September 30, 2007, all three primary nitrogen fertilizer units experienced eighteen days of downtime associated with the flood. In addition, the UAN plant also experienced unscheduled downtime for repairs and maintenance. On-stream factors for the three months ended September 30, 2006 were negatively impacted by a major scheduled turnaround at the nitrogen fertilizer plant and unscheduled downtime associated with repairs and maintenance to the ammonia plant. It is typical to experience brief outages in complex manufacturing operations such as our nitrogen fertilizer plant which result in less than one hundred percent on-stream availability for one or more specific units.

Plant gate prices are prices FOB the delivery point less any freight cost we absorb to deliver the product. We believe plant gate price is meaningful because we sell products both FOB our plant gate (sold plant) and FOB the customer s designated delivery site (sold delivered) and the percentage of sold plant versus sold delivered can change month to month or three months to three months. The plant gate price provides a measure that is consistently comparable period to period. Plant gate prices for the three months ended September 30, 2007 for ammonia and UAN were greater than plant gate prices for the comparable period of 2006 by 28% and 66%, respectively. This dramatic increase in nitrogen fertilizer prices was not the result of an increase in natural gas prices, but rather the result of increased demand for nitrogen-based fertilizers due to the increased use of corn for the production of ethanol and an overall increase in prices for corn, wheat and soybeans, the primary row crops in our region. This increase in demand for nitrogen-based fertilizer has created an environment in which nitrogen fertilizer prices have disconnected from their traditional correlation to natural gas prices.

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

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of petroleum coke expense, hydrogen reimbursement and freight and distribution expenses. Cost of product sold excluding depreciation and amortization for the three months ended September 30, 2007 was $3.7 million compared to $8.3 million for the three months ended September 30, 2006. The decrease of $4.6 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was primarily the result of increased hydrogen reimbursement due to the transfer of hydrogen to our Petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit and reduced freight expense partially offset by an increase in petroleum coke costs.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Nitrogen fertilizer operations include costs associated with the actual operations of our nitrogen plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen direct operating expenses exclusive of depreciation and amortization for the three months ended September 30, 2007 were $14.9 million as compared to $18.5 million for the three months ended September 30, 2006. The decrease of $3.6 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was primarily the result of decreases in expenses associated with turnaround ($2.3 million), outside services ($0.6 million), royalties and other ($0.5 million), utilities ($0.2 million), labor ($0.1 million) and chemicals ($0.1 million). These decreases in direct operating expenses were partially offset by increases in expenses associated with repairs and maintenance ($0.4 million).

Net Costs Associated with Flood. Nitrogen fertilizer net costs associated with flood for the three months ended September 30, 2007 approximated $1.9 million as compared to none for the three months ended September 30, 2006. Total gross costs recorded as a result of the damage to the fertilizer plant for the three months ended September 30, 2007 were approximately $5.1 million. Included in this cost was approximately $0.8 million recorded for depreciation for the temporarily idle facilities, $0.7 million for internal salaries and $3.6 million for other repair and related costs. Total accounts receivable from insurers approximated $3.2 million at September 30, 2007, for which we believe collection is probable.

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization decreased to $3.6 million for the three months ended September 30, 2007 as compared to $4.3 million for the three months ended September 30, 2006. During the restoration period for the nitrogen fertilizer operations due to the flood, $0.8 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this $0.8 million reclassification, nitrogen fertilizer depreciation and amortization would have increased by approximately $0.1 million for the three months ended September 30, 2007 compared to the three months ended September 30, 2006.

Operating Income. Nitrogen fertilizer operating income was $13.8 million for the three months ended September 30, 2007 as compared to an operating loss of $3.0 million for the three months ended September 30, 2006. This increase of $16.8 million for the three months ended September 30, 2007 as compared to the three months ended September 30, 2006 was primarily the result of increased fertilizer prices over the comparable periods and a $4.6 million reduction in cost of product sold excluding depreciation and amortization due to increased hydrogen reimbursement and reduced freight expense partially offset by an increase in petroleum coke costs. Additionally, decreased direct operating expenses associated with turnaround ($2.3 million), outside services ($0.6 million), royalties and other ($0.5 million), utilities ($0.2 million), labor ($0.1 million) and chemicals ($0.1 million) also contributed to the positive operating income comparison over the comparable periods. These decreases in expenses were partially offset by reduced sales volumes and increased direct operating expenses primarily the result of increases in repairs and maintenance ($0.4 million).

Nine Months Ended September 30, 2007 Compared to the Nine Months Ended September 30, 2006.

Consolidated

Net Sales. Consolidated net sales were $1,819.9 million for the nine months ended September 30, 2007 compared to $2,329.2 million for the nine months ended September 30, 2006. The decrease of $509.3 million for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily due to a decrease in petroleum net sales of $497.7 million that resulted from lower sales volumes ($656.8 million), partially offset by higher product prices ($159.1 million). Nitrogen fertilizer net sales decreased $13.1 million for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 due to lower sales volumes ($28.6 million), partially offset by higher plant gate prices ($15.5 million).

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $1,319.5 million for the nine months ended September 30, 2007 as compared to $1,848.1 million for the nine months ended September 30, 2006. The decrease of $528.6 million for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 primarily resulted from a significant reduction in refined fuel production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the flood.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Consolidated direct operating expenses exclusive of depreciation and amortization were $218.8 million for the nine months ended September 30, 2007 as compared to $144.5 million for the nine months ended September 30, 2006. This increase of $74.3 million for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was due to an increase in petroleum direct operating expenses of $73.4 million, primarily related to the refinery turnaround, and an increase in nitrogen fertilizer direct operating expenses of $0.9 million.

Selling, General and Administrative Expenses Exclusive of Depreciation and Amortization. Consolidated selling, general and administrative expenses exclusive of depreciation and amortization were $42.1 million for the nine months ended September 30, 2007 as compared to $32.8 million for the nine months ended September 30, 2006. This variance was primarily the result of increases in administrative labor primarily related to deferred compensation ($9.2 million), other costs ($0.7 million), bank charges ($0.6 million) and office costs ($0.3 million) partially offset by reductions in expenses associated with asset retirements ($1.1 million).

Net Costs Associated with Flood. Consolidated net costs associated with flood for the nine months ended September 30, 2007 approximated $34.3 million as compared to none for the nine months ended September 30, 2006. Total gross costs recorded for the nine months ended September 30, 2007 were approximately $130.7 million. Of these gross costs, approximately $91.2 million were associated with repair and other matters as a result of the damage to the Company s facilities. Included in this cost was $7.6 million of depreciation for the temporarily idled facilities, $5.9 million for internal salaries, $2.9 million of professional fees and $74.8 million for other repair and related costs. There were approximately $39.5 million costs recorded with respect to the environmental remediation and property damage. Total accounts receivable from insurers approximated $96.4 million at September 30, 2007, for which we believe collection is probable.

Depreciation and Amortization. Consolidated depreciation and amortization was $42.7 million for the nine months ended September 30, 2007 as compared to $36.8 million for the nine months ended September 30, 2006. During the restoration period for the refinery and our nitrogen fertilizer operations due to the flood, $7.6 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this $7.6 million reclassification, the increase in consolidated depreciation and amortization for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006 would have been approximately $13.5 million. This adjusted increase in consolidated depreciation and amortization for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily the result of the completion of the several large capital projects in late 2006 and during the nine months ended September 30, 2007 in our Petroleum business

Operating Income. Consolidated operating income was $162.5 million for the nine months ended September 30, 2007 as compared to operating income of $267.0 million for the nine months ended September 30, 2006. For the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006, petroleum operating income decreased $104.1 million and nitrogen fertilizer operating income increased by $0.8 million.

Interest Expense. Consolidated interest expense for the nine months ended September 30, 2007 was $46.0 million as compared to interest expense of $33.0 million for the nine months ended September 30, 2006. This 39% increase for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 primarily resulted from an overall increase in the index rates (primarily LIBOR) and an increase in average borrowings outstanding during the comparable periods. Partially offsetting these negative impacts on consolidated interest expense was a $1.7 million increase in capitalized interest over the comparable periods due to the increase of capital projects in progress during the nine months ended September 30, 2007. Additionally, consolidated interest expense over the comparable periods was partially offset by decreases in the applicable margins under our Credit Facility dated December 28, 2006 as compared to our borrowing facility in effect during the nine months ended September 30, 2006.

Interest Income. Interest income was $0.8 million for the nine months ended September 30, 2007 as compared to $2.8 million for the nine months ended September 30, 2006.

Gain (loss) on Derivatives. We have determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* For the nine months ended September 30, 2007, we incurred $251.9 million in losses on derivatives. This compares to a $44.7 million gain on derivatives for the nine months ended September 30, 2006. This significant change in gain (loss) on derivatives for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily attributable to the realized and unrealized gains (losses) on our Cash Flow Swap. Realized losses on the Cash Flow Swap for the nine months ended September 30, 2007 and the nine months ended September 30, 2006 were $142.6 million and $46.2 million, respectively. The increase in realized losses over the comparable periods was primarily the result of higher average crack spreads for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006. Unrealized gains or losses represent the change in the mark-to-market value on the unrealized portion of the Cash Flow Swap based on changes in the NYMEX crack spread that is the basis for the Cash Flow Swap. Unrealized losses on our Cash Flow Swap for the nine months ended September 30, 2007 were $98.3 million and reflect an increase in the crack spread values on the unrealized positions comprising the Cash Flow Swap. In contrast, the unrealized portion of the Cash Flow Swap for the nine months ended September 30, 2006 reported mark-to-market gains of $80.3 million and reflect a decrease in the crack spread values on the unrealized positions comprising the Cash Flow Swap. In addition, the outstanding term of the Cash Flow Swap at the end of each period also affects the impact of changes in the underlying crack spread. As of September 30, 2007, the Cash Flow Swap had a remaining term of approximately two years and nine months whereas as of September 30, 2006, the remaining term on the Cash Flow Swap was approximately three years and nine months. As a result of the longer remaining term as of September 30, 2006, a similar change in crack spread will have a greater impact on the unrealized gains or losses.

Provision for Income Taxes. Income tax benefit for the nine months ended September 30, 2007 was $93.4 million, or 69% of loss before income taxes, as compared to income tax expense of $111.0 million, or 39% of earnings before income taxes, for the nine months ended September 30, 2006. The annualized effective rate for 2007, which was applied to loss before income taxes for the nine month period ended September 30, 2007, is higher than the comparable annualized effective tax rate for 2006, which was applied to earnings before income taxes for the nine months ended September 30, 2006, primarily due to the correlation between the amount of credits which are projected to be generated in 2007 from the production of ultra low sulfur diesel fuel and the reduced level of projected earnings before income taxes for 2007.

Minority Interest in (income) loss of Subsidiaries. Minority interest in loss of subsidiaries for the nine months ended September 30, 2007 was $0.2 million. Minority interest relates to common stock in two of our subsidiaries owned by our chief executive officer. In October 2007, in connection with our initial public offering, our chief executive officer exchanged his common stock in our subsidiaries for common stock of CVR Energy.

Net Income. For the nine months ended September 30, 2007, net income decreased to a net loss of $40.9 million as compared to net income of $170.8 million for the nine months ended September 30, 2006.

Table of Contents

Net income decreased $211.7 million for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006, primarily due to the refinery turnaround, downtime and costs associated with the flood and a significant change in the value of the Cash Flow Swap over the comparable periods.

Petroleum

Net Sales. Petroleum net sales were $1,707.3 million for the nine months ended September 30, 2007 compared to $2,205.0 million for the nine months ended September 30, 2006. The decrease of $497.7 million from the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily the result of significantly lower sales volumes ($656.8 million), partially offset by higher product prices ($159.1 million). Overall sales volumes of refined fuels for the nine months ended September 30, 2007 decreased 29% as compared to the nine months ended September 30, 2006. The decreased sales volume primarily resulted from a significant reduction in refined fuel production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the flood. Our average sales price per gallon for the nine months ended September 30, 2007 for gasoline of $2.14 and distillate of $2.12 increased by 8% and 4%, respectively, as compared to the nine months ended September 30, 2006.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Petroleum cost of product sold exclusive of depreciation and amortization was $1,312.2 million for the nine months ended September 30, 2007 compared to $1,828.1 million for the nine months ended September 30, 2006. The decrease of $515.9 million from the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily the result of a significant reduction in crude throughput due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the flood. In addition to the refinery turnaround and the flood, crude oil prices, reduced sales volumes and the impact of FIFO accounting also impacted cost of product sold during the comparable periods. Our average cost per barrel of crude oil for the nine months ended September 30, 2007 was $60.90, compared to $63.87 for the comparable period of 2006, a decrease of 5%. Sales volume of refined fuels decreased 29% for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 principally due to the refinery turnaround and flood. In addition, under our FIFO accounting method, changes in crude oil prices can cause fluctuations in the inventory valuation of our crude oil, work in process and finished goods, thereby resulting in FIFO inventory gains when crude oil prices increase and FIFO inventory losses when crude oil prices decrease. For the nine months ended September 30, 2007, we had FIFO inventory gains of $37.4 million compared to FIFO inventory gains of $13.0 million for the comparable period of 2006.

Refining margin per barrel of crude throughput increased from $14.68 for the nine months ended September 30, 2006 to $22.32 for the nine months ended September 30, 2007 primarily due to the 33% increase ($3.82 per barrel) in the average NYMEX 2-1-1 crack spread over the comparable periods and positive regional differences between gasoline and distillate prices in our primary marketing region (the Coffeyville supply area) and those of the NYMEX. The average gasoline basis for the nine months ended September 30, 2007 increased by $2.92 per barrel to $4.74 per barrel compared to $1.82 per barrel in the comparable period of 2006. The average distillate basis for the nine months ended September 30, 2007 increased by $1.64 per barrel to $9.54 per barrel compared to $7.90 per barrel in the comparable period of 2006. The positive effect of the increased NYMEX 2-1-1 crack spreads and refined fuels basis over the comparable periods was partially offset by reductions in the crude oil differentials over the comparable periods. Decreased discounts for sour crude oils evidenced by the $0.74 per barrel, or 14%, decrease in the spread between the WTI price, which is a market indicator for the price of light sweet crude, and the WTS price, which is an indicator for the price of sour crude, negatively impacted refining margin for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance (turnaround), labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $170.7 million for the nine months ended September 30, 2007 compared to direct operating expenses of $97.3 million for the nine months ended September 30, 2006. The increase of $73.4 million for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006 was the result of increases in expenses associated with repairs and maintenance related to the refinery turnaround ($74.9 million), taxes ($6.8 million), insurance ($1.9 million), direct labor ($1.3 million), outside services ($1.2 million) and production chemicals ($0.4 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with energy and utilities ($5.8 million), repairs and maintenance ($3.0 million), environmental compliance ($2.4 million), rent and lease ($1.7 million) and operating materials ($0.6 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for the nine months ended September 30, 2007 increased to $9.64 per barrel as compared to $3.79 per barrel for the nine months ended September 30, 2006 principally due to refinery turnaround expenses and the related downtime associated with the turnaround and the flood and the corresponding impact on overall crude oil throughput and production volume.

Net Costs Associated with Flood. Petroleum net costs associated with the flood for the nine months ended September 30, 2007 approximated $30.6 million as compared to none for the nine months ended September 30, 2006. Total gross costs recorded for the nine months ended September 30, 2007 were approximately $123.3 million. Of these gross costs approximately $83.8 million were associated with repair and other matters as a result of the damage to the refinery. Included in this cost was approximately $6.8 million recorded for depreciation for the temporarily idle facilities, $4.6 million for internal salaries, $1.8 million of professional fees and $70.6 million for other repair and related costs. There were approximately $39.5 million recorded with respect to the environmental remediation and property damage. Total accounts receivable from insurers approximated $92.7 million at September 30, 2007, for which we believe collection is probable.

Depreciation and Amortization. Petroleum depreciation and amortization was $29.7 million for the nine months ended September 30, 2007 as compared $23.6 million for the nine months ended September 30, 2006, an increase of $6.1 million over the comparable periods. During the restoration period for the refinery due to the flood, $6.8 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this $6.8 million reclassification, the increase in petroleum depreciation and amortization for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006 would have been approximately $12.9 million. This adjusted increase in petroleum depreciation and amortization for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily the result of the completion of the several large capital projects in late 2006 and during the nine months ended September 30, 2007.

Operating Income. Petroleum operating income was $129.4 million for the nine months ended September 30, 2007 as compared to operating income of $233.5 million for the nine months ended September 30, 2006. This decrease of $104.1 million from the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily the result of the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the flood. The turnaround negatively impacted daily refinery crude throughput and refined fuels production. Substantially all of the refinery s units damaged by the flood were back in operation by August 20, 2007. In addition, direct operating expenses increased substantially during the nine months ended September 30, 2007 related to repairs and maintenance associated with the refinery turnaround ($74.9 million), taxes ($6.8 million), insurance ($1.9 million), direct labor ($1.3 million), outside services ($1.2 million) and production chemicals ($0.4 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with energy and utilities ($5.8 million), repairs and maintenance ($3.0 million), environmental compliance ($2.4 million), rent and lease ($1.7 million) and operating materials ($0.6 million).

Fertilizer

Net Sales. Nitrogen fertilizer net sales were $115.1 million for the nine months ended September 30, 2007 compared to $128.2 million for the nine months ended September 30, 2006. The decrease of $13.1 million from the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was the result of reductions in overall sales volumes ($28.6 million), partially offset by higher plant gate prices ($15.5 million).

In regard to product sales volumes for the nine months ended September 30, 2007, our nitrogen operations experienced a decrease of 39% in ammonia sales unit volumes (38,076 tons) and a decrease of 13% in UAN sales unit volumes (63,542 tons). The decrease in ammonia sales volume was the result of decreased production volumes during the nine months ended September 30, 2007 relative to the comparable period of 2006 due to unscheduled downtime at our fertilizer plant and the transfer of hydrogen to our Petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit. The transfer of hydrogen to our Petroleum operations is scheduled to be replaced with hydrogen produced by the new continuous catalytic reformer scheduled to be completed in the late 2007 to early 2008. On-stream factors (total number of hours operated divided by total hours in the reporting period) for all units of our nitrogen operations (gasifier, ammonia plant and UAN plant) were less than the comparable period primarily due to approximately eighteen days of downtime for all three primary nitrogen units associated with the flood and nine days of downtime related to compressor repairs in the ammonia unit In addition, all three primary units also experienced brief and unscheduled downtime for repairs and maintenance during the nine months ended September 30, 2007. It is typical to experience brief outages in complex manufacturing operations such as our nitrogen fertilizer plant which result in less than one hundred percent on-stream availability for one or more specific units.

Plant gate prices are prices FOB the delivery point less any freight cost we absorb to deliver the product. We believe plant gate price is meaningful because we sell products both FOB our plant gate (sold plant) and FOB the customer s designated delivery site (sold delivered) and the percentage of sold plant versus sold delivered can change month to month or nine months to nine months. The plant gate price provides a measure that is consistently comparable period to period. Plant gate prices for the nine months ended September 30, 2007 for ammonia and UAN were greater than plant gate prices for the comparable period of 2006 by 3% and 20%, respectively. Our ammonia and UAN sales prices for product shipped during the nine months ended September 30, 2006 generally followed volatile natural gas prices; however, it is typical for the reported pricing in our fertilizer business to lag the spot market prices for nitrogen fertilizer due to forward price contracts. As a result, forward price contracts entered into the late summer and fall of 2005 (during a period of relatively high natural gas prices due to the impact of hurricanes Rita and Katrina) comprised a significant portion of the product shipped in the spring of 2006. However, as natural gas prices moderated in the spring and summer of 2006, fertilizer nitrogen fertilizer prices declined and the spot and fill contracts entered into and shipped during this lower natural gas prices environment realized lower average netbacks. Ammonia and UAN sales prices for the nine months ending September 2007 were impacted by both relatively low natural gas prices and a dramatic increase in nitrogen fertilizer prices driven by increased demand for fertilizer due to the increased use of corn for the production of ethanol and an overall increase in prices for corn, wheat and soybeans, the primary row crops in our region. This increase in demand for nitrogen fertilizer has created an environment in which nitrogen fertilizer prices have disconnected from their traditional correlation to natural gas.

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

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of petroleum coke expense, hydrogen reimbursement and freight and distribution expenses. Cost of product sold excluding depreciation and amortization for the nine months ended September 30, 2007 was $9.9 million compared to $23.8 million for the nine months ended September 30, 2006. The decrease of $13.9 million for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily the result of increased hydrogen reimbursement due to the transfer of hydrogen to our Petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit and reduced freight expense partially offset by an increase in petroleum coke costs.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Nitrogen fertilizer operations include costs associated with the actual operations of our nitrogen plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen direct operating expenses exclusive of depreciation and amortization for the nine months ended September 30, 2007 were $48.1 million as compared to $47.2 million for the nine months ended September 30, 2006. The increase of $0.9 million for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily the result of increases in repairs and maintenance

($3.6 million), utilities ($1.0 million), equipment rental ($0.4 million), and insurance ($0.3 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with turnaround ($2.6 million), royalties ($0.6 million), catalyst ($0.5 million), outside services ($0.3 million) and chemicals ($0.3 million).

Net Costs Associated with Flood. Nitrogen fertilizer net costs associated with flood for the nine months ended September 30, 2007 approximated $2.0 million as compared to none for the nine months ended September 30, 2006. Total gross costs recorded as a result of the damage to the fertilizer plant for the nine months ended September 30, 2007 were approximately $5.2 million. Included in this cost was approximately $0.8 million recorded for depreciation for the temporarily idle facilities, $0.7 million for internal salaries and $3.7 million for other repair and related costs. Total accounts receivable from insurers approximated $3.2 million at September 30, 2007, for which we believe collection is probable.

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization decreased to $12.4 million for the nine months ended September 30, 2007 as compared to $12.7 million for the nine months ended September 30, 2006. During the restoration period for the nitrogen fertilizer operations due to the flood, $0.8 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this $0.8 reclassification, nitrogen fertilizer depreciation and amortization would have increased by approximately $0.5 million for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006.

Operating Income. Nitrogen fertilizer operating income was $34.9 million for the nine months ended September 30, 2007 as compared to $34.1 million for the nine months ended September 30, 2006. This increase of $0.8 million for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was primarily the result of a $13.9 million reduction in cost of product sold excluding depreciation and amortization due to increased hydrogen reimbursement and reduced freight expense partially offset by an increase in petroleum coke costs and decreased direct operating expenses associated with turnaround ($2.6 million), royalties ($0.6 million), catalyst ($0.5 million), outside services ($0.3 million) and chemicals ($0.3 million). These decreases in expenses were partially offset by reduced sales volumes and increased direct operating expenses primarily the result of increases in repairs and maintenance ($3.6 million), utilities ($1.0 million), equipment rental ($0.4 million) and insurance ($0.3 million).

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from our operating activities, existing cash balances and our existing revolving credit facility. Additionally, we have borrowings from related parties. Our ability to generate sufficient cash flows from our operating activities will continue to be primarily dependent on producing or purchasing, and selling, sufficient quantities of refined products at margins sufficient to cover fixed and variable expenses.

Our liquidity was enhanced during the fourth quarter of 2007 by the receipt of $408.5 million of net proceeds from our initial public offering after the payment of underwriting discounts and commissions, but before the deduction of offering expenses. We believe that our cash flows from operations, borrowings under our revolving credit facilities, proceeds from the initial public offering and other capital resources will be sufficient to satisfy the anticipated cash requirements associated with our existing operations for at least the next 12 months. However, our future capital expenditures and other cash requirements could be higher than we currently expect as a result of various factors. Additionally, our ability to generate sufficient cash from our operating activities depends on our future performance, which is subject to general economic, political, financial, competitive, and other factors beyond our control.

Debt

Credit Facility

On December 28, 2006, our subsidiary Coffeyville Resources, LLC entered into a Credit Facility which provided financing of up to $1.075 billion. The Credit Facility consisted of $775.0 million of tranche D term loans, a $150.0 million revolving credit facility, and a funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap. On October 26, 2007, we repaid $280.0 million of the tranche D term loans with proceeds from our initial public offering. The Credit Facility is guaranteed by all of our subsidiaries and is secured by substantially all of their assets including the equity of our subsidiaries on a first lien priority basis.

The tranche D term loans outstanding are subject to quarterly principal amortization payments of 0.25% of the outstanding balance commencing on April 1, 2007 and increasing to 23.5% of the outstanding principal balance on April 1, 2013 and the next two quarters, with a final payment of the aggregate outstanding balance on December 28, 2013.

The revolving loan facility of $150.0 million provides for direct cash borrowings for general corporate purposes and on a short-term basis. Letters of credit issued under the revolving loan facility are subject to a $75.0 million sub-limit. The revolving loan commitment expires on December 28, 2012. The borrower has an option to extend this maturity upon written notice to the lenders; however, the revolving loan maturity cannot be extended beyond the final maturity of the term loans, which is December 28, 2013. As of September 30, 2007, we had available $93.1 million under the revolving credit facility. As of October 26, 2007, after giving effect to our initial public offering, we had available $110.6 million under the revolving credit facility.

The $150.0 million funded letter of credit facility provides credit support for our obligations under the Cash Flow Swap. The funded letter of credit facility is fully cash collateralized by the funding by the lenders of cash into a credit linked deposit account. This account is held by the funded letter of credit issuing bank. Contingent upon the requirements of the Cash Flow Swap, the borrower has the ability to reduce the funded letter of credit at any time upon written notice to the lenders. The funded letter of credit facility expires on December 28, 2010.

The Credit Facility incorporates the following pricing by facility type:

Tranche D term loans bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 2.25%, or, at the borrower s option, (b) LIBOR plus 3.25% (with step-downs to the prime rate/federal funds rate plus 1.75% or 1.50% or LIBOR plus 2.75% or 2.50%, respectively, upon achievement of certain rating conditions).

Revolving loan borrowings bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 2.25%, or, at the borrower s option, (b) LIBOR plus 3.25% (with step-downs to the prime rate/federal funds rate plus 1.75% or 1.50% or LIBOR plus 2.75% or 2.50%, respectively, upon achievement of certain rating conditions).

Letters of credit issued under the $75.0 million sub-limit available under the revolving loan facility are subject to a fee equal to the applicable margin on revolving LIBOR loans owing to all revolving lenders and a fronting fee of 0.25% per annum owing to the issuing lender.

Funded letters of credit are subject to a fee equal to the applicable margin on term LIBOR loans owed to all funded letter of credit lenders and a fronting fee of 0.125% per annum owing to the issuing lender. The borrower is also obligated to pay a fee of 0.10% to the administrative agent on a quarterly basis based on the average balance of funded letters of credit outstanding during the calculation period, for the maintenance of a credit-linked deposit account backstopping funded letters of credit.

In addition to the fees stated above, the Credit Facility requires the borrower to pay 0.50% per annum in commitment fees on the unused portion of the revolving loan facility.

The Credit Facility requires the borrower to prepay outstanding loans, subject to certain exceptions, with:

100% of the net asset sale proceeds received from specified asset sales and net insurance/condemnation proceeds, if the borrower does not reinvest those proceeds in assets to be used in its business or make other permitted investments within 12 months or if, within 12 months of receipt, the borrower does not contract to reinvest those proceeds in assets to be used in its business or make other permitted investments within 18 months of receipt, each subject to certain limitations;

100% of the cash proceeds from the incurrence of specified debt obligations;

75% of consolidated excess cash flow less 100% of voluntary prepayments made during the fiscal year; provided that with respect to any fiscal year commencing with fiscal 2008 this percentage will be reduced to 50% if the total leverage ratio at the end of such fiscal year is less than 1.50:1.00 or 25% if the total leverage ratio as of the end of such fiscal year is less than 1.00:1.00; and

100% of the cash proceeds received by us from any initial public offering or secondary registered offering of equity interests, until the aggregate amount of such proceeds is equal to $280 million.

Mandatory prepayments will be applied first to the term loan, second to the swing line loans, third to the revolving loans, fourth to outstanding reimbursement obligations with respect to revolving letters of credit and funded letters of credit, and fifth to cash collateralize revolving letters of credit and funded letters of credit. Voluntary prepayments of loans under the Credit Facility are permitted, in whole or in part, at the borrower s option, without premium or penalty.

The Credit Facility contains customary covenants. These agreements, among other things, restrict, subject to certain exceptions, the ability of Coffeyville Resources, LLC and its subsidiaries to incur additional indebtedness, create liens on assets, make restricted junior payments, enter into agreements that restrict subsidiary distributions, make investments, loans or advances, engage in mergers, acquisitions or sales of assets, dispose of subsidiary interests, enter into sale and leaseback transactions, engage in certain transactions with affiliates and stockholders, change the business conducted by the credit parties, and enter into hedging agreements. The Credit Facility provides that Coffeyville Resources, LLC may not enter into commodity agreements if, after giving effect thereto, the exposure under all such commodity agreements exceeds 75% of Actual Production (the borrower s estimated future production of refined products based on the actual production for the three prior months) or for a term of longer than six years from December 28, 2006. In addition, the borrower may not enter into material amendments related to any material rights under the Cash Flow Swap or the Partnership s partnership agreement without the prior written approval of the lenders. These limitations are subject to critical exceptions and exclusions and are not designed to protect investors in our common stock.

The Credit Facility also requires the borrower to maintain certain financial ratios as follows:

Fiscal Quarter Ending	Minimum Interest Coverage Ratio	Maximum Leverage Ratio
September 30, 2007	2.75:1.00	4.25:1.00
December 31, 2007	2.75:1.00	4.00:1.00
March 31, 2008	3.25:1.00	3.25:1.00
June 30, 2008	3.25:1.00	3.00:1.00
September 30, 2008	3.25:1.00	2.75:1.00
December 31, 2008	3.25:1.00	2.50:1.00
March 31, 2009 and thereafter	3.75:1.00	2.25:1.00 to December 31, 2009, 2.00:1.00 thereafter

The computation of these ratios is governed by the specific terms of the Credit Facility and may not be comparable to other similarly titled measures computed for other purposes or by other companies. The minimum interest coverage ratio is the ratio of consolidated adjusted EBITDA to consolidated cash interest expense over a four quarter period.

The maximum leverage ratio is the ratio of consolidated total debt to consolidated adjusted EBITDA over a four quarter period. The computation of these ratios requires a calculation of consolidated adjusted EBITDA. In general, under the terms of our Credit Facility, consolidated adjusted EBITDA is calculated by adding consolidated net income, consolidated interest expense, income taxes, depreciation and amortization, other non- cash expenses, any fees and expenses related to permitted acquisitions, any non-recurring expenses incurred in connection with the issuance of debt or equity, management fees, any unusual or non-recurring charges up to 7.5% of consolidated adjusted EBITDA, any net after-tax loss from disposed or discontinued operations, any incremental property taxes related to abatement non-renewal, any losses attributable to minority equity interests and major scheduled turnaround expenses. As of September 30, 2007, we were in compliance with our covenants under the Credit Facility.

We present consolidated adjusted EBITDA because it is a material component of material covenants within our current Credit Facility and significantly impacts our liquidity and ability to borrow under our revolving line of credit. However, consolidated adjusted EBITDA is not a defined term under GAAP and should not be considered as an alternative to operating income or net income as a measure of operating results or as an alternative to cash flows as a measure of liquidity. Consolidated adjusted EBITDA is calculated under the Credit Facility as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
	(Unaudited) (In millions)			
Consolidated Financial Results				
Net income (loss)	$ 129.0	$ 13.4	$ 170.8	$ (40.9)
Plus:				
Depreciation and amortization	12.8	18.1	36.8	50.3
Interest expense	10.7	18.3	33.0	46.0
Income tax expense (benefit)	85.3	47.6	111.0	(93.4)
Funded letters of credit expense and interest rate swap not included in interest expense	(0.4)	0.7	0.2	0.9
Major scheduled turnaround expense	4.1		4.4	76.8
Unrealized (gain) or loss on derivatives	(173.7)	(86.2)	(81.6)	103.8
Non-cash compensation expense for equity awards		4.5	2.3	11.3
(Gain) or loss on disposition of fixed assets	0.8	0.1	1.2	1.2
Minority interest		0.1		(0.2)
Management fees	0.5	0.5	1.6	1.5
Adjusted EBITDA	$ 69.1	$ 17.1	$ 279.7	$ 157.3

In addition to the financial covenants summarized in the table above, the Credit Facility restricts the capital expenditures of Coffeyville Resources, LLC to $375 million in 2007, $125 million in 2008, $125 million in 2009, $80 million in 2010, and $50 million in 2011 and thereafter. The capital expenditures covenant includes a mechanism for carrying over the excess of any previous year s capital expenditure limit. The capital expenditures limitation will not apply for any fiscal year commencing with fiscal 2009 if the borrower consummates an initial public offering and obtains a total leverage ratio of less than or equal to 1.25:1.00 for any quarter commencing with the quarter ended December 31, 2008. We believe the limitations on our capital expenditures imposed by the Credit Facility should allow us to meet our current capital expenditure needs. However, if future events require us or make it beneficial for us to make capital expenditures beyond those currently planned, we would need to obtain consent from the lenders under our Credit Facility.

The Credit Facility also contains customary events of default. The events of default include the failure to pay interest and principal when due, including fees and any other amounts owed under the Credit Facility, a breach of certain covenants under the Credit Facility, a breach of any representation or warranty contained in the Credit Facility, any default under any of the documents entered into in connection with the Credit Facility, the failure to pay principal or interest or any other amount payable under other debt arrangements in an aggregate amount of at least $20 million, a breach or default with respect to material terms under other debt arrangements in an aggregate amount of at least $20 million which results in the debt becoming payable or declared due and payable before its stated maturity, a breach or default under the Cash Flow Swap that would permit the holder or holders to terminate the Cash Flow Swap, events of bankruptcy, judgments and attachments exceeding $20 million, events relating to employee benefit plans resulting in liability in excess of $20 million, a change in control, the guarantees, collateral documents or the Credit Facility failing to be in full force and effect or being declared null and void, any guarantor repudiating its obligations, the failure of the collateral agent under the Credit Facility to have a lien on any material portion of the collateral, and any party under the Credit Facility (other than the agent or lenders under the Credit Facility) contesting the validity or enforceability of the Credit Facility.

Under the terms of our Credit Facility, our initial public offering was deemed a Qualified IPO because the offering generated at least $250 million of gross proceeds and we used the proceeds of the offering to repay at least $275 million of term loans under the Credit Facility. As a result of our Qualified IPO, the interest margin on LIBOR loans may in the future decrease from 3.25% to 2.75% (if we have credit ratings of B2/B) or 2.50% (if we have credit ratings of B1/B+). Interest on base rate loans will similarly be adjusted. In addition, as a result of our Qualified IPO, (1) we will be allowed to borrow an additional $225 million under the Credit Facility after June 30, 2008 to finance capital enhancement projects if we are in pro forma compliance with the financial covenants in the Credit Facility and the rating agencies confirm our ratings, (2) we will be allowed to pay an additional $35 million of dividends each year, if our corporate family ratings are at least B2 from Moody s and B from S&P, (3) we will not be subject to any capital expenditures limitations commencing with fiscal 2009 if our total leverage ratio is less than or equal to 1.25:1 for any quarter commencing with the quarter ended December 31, 2008, and (4) at any time after March 31, 2008 we will be allowed to reduce the Cash Flow Swap to not less than 35,000 barrels a day for fiscal 2008 and terminate the Cash Flow Swap for any year commencing with fiscal 2009, so long as our total leverage ratio is less than or equal to 1.25:1 and we have a corporate family rating of at least B2 from Moody s and B from S&P.

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

At December 31, 2006 and September 30, 2007, funded long-term debt, including current maturities, totaled $775.0 million and $771.1 million, respectively, of tranche D term loans. Other commitments at December 31, 2006 and September 30, 2007 included a $150.0 million funded letter of credit facility and a $150.0 million revolving credit facility. As of December 31, 2006, the commitment outstanding on the revolving credit facility was a $6.4 million letter of credit issued to provide transitional collateral to the lender that issued $3.2 million in letters of credit in support of certain environmental obligations and $3.2 million in letters of credit to secure transportation services for a crude oil pipeline. As of September 30, 2007, the commitment outstanding on the revolving credit facility was $56.9 million, including $20.0 million in borrowings, $3.3 million in letters of credit in support of certain environmental obligations, $3.0 million in support of surety bonds in place to support state and federal excise tax for refined fuels, and $30.6 million in letters of credit to secure transportation services for a crude oil pipeline.

Payment Deferrals Related to Cash Flow Swap

As a result of the flood and the temporary cessation of our operations on June 30, 2007, Coffeyville Resources, LLC entered into several deferral agreements with J. Aron with respect to the Cash Flow Swap. These deferral agreements deferred to January 31, 2008 the payment of approximately $123.7 million (plus accrued interest) which we owed to J. Aron. J. Aron has agreed to further defer these payments to August 31, 2008 but we will be required to use 37.5% of our consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferred amounts.

> On June 26, 2007, Coffeyville Resources, LLC and J. Aron & Company entered into a letter agreement in which J. Aron deferred to August 7, 2007 a $45 million payment which we owed to J. Aron under the Cash Flow Swap for the period ending June 30, 2007. We agreed to pay interest on the deferred amount at the rate of LIBOR plus 3.25%.
>
> On July 11, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to July 25, 2007 a separate $43.7 million payment which we owed to J. Aron under the Cash Flow Swap for the period ending June 30, 2007. J. Aron deferred the $43.7 million payment on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee

one half of the payment and (b) interest accrued on the $43.7 million from July 9, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On July 26, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to September 7, 2007 both the $45 million payment due August 7, 2007 (and accrued interest) and the $43.7 million payment due July 25, 2007 (and accrued interest). J. Aron deferred these payments on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one half of the payments and (b) interest accrued on the amounts from July 26, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On August 23, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to January 31, 2008 the $45 million payment due September 7, 2007 (and accrued interest), the $43.7 million payment due September 7, 2007 (and accrued interest) and the $35 million payment which we owed to J. Aron under the Cash Flow Swap to settle hedged volume through August 15, 2007. J. Aron deferred these payments (totaling $123.7 million plus accrued interest) on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one half of the payments and (b) interest accrued on the amounts to the date of payment at the rate of LIBOR plus 1.50%.

Nitrogen Fertilizer Limited Partnership

The managing general partner of the Partnership may, from time to time, seek to raise capital through a public or private offering of limited partner interests in the Partnership. Any decision to pursue such a transaction would be made in the discretion of the managing general partner, not us, and any proceeds raised in a primary offering would be for the benefit of the Partnership, not us (although in some cases, depending on the structure of the transaction, the Partnership might remit proceeds to us). If the managing general partner elects to pursue a public or private offering of limited partner interests in the Partnership, we expect that any such transaction would require amendments to our Credit Facility, as well as the Cash Flow Swap, in order to remove the Partnership and its subsidiaries as obligors under such instruments. Any such amendments could result in significant changes to our Credit Facility s pricing, mandatory repayment provisions, covenants and other terms and could result in increased interest costs and require payment by us of additional fees. We have agreed to use our commercially reasonable efforts to obtain such amendments if the managing general partner elects to cause the Partnership to pursue a public or private offering and gives us at least 90 days written notice.

However, we cannot assure you that we will be able to obtain any such amendment on terms acceptable to us or at all. If we are not able to amend our Credit Facility on terms satisfactory to us, we may need to refinance them with other facilities. We will not be considered to have used our commercially reasonable efforts to obtain such amendments if we do not effect the requested modifications due to (i) payment of fees to the lenders or the swap counterparty, (ii) the costs of this type of amendment, (iii) an increase in applicable margins or spreads or (iv) changes to the terms required by the lenders including covenants, events of default and repayment and prepayment provisions; provided that (i), (ii), (iii) and (iv) in the aggregate are not likely to have a material adverse effect on us. In order to effect the requested amendments, we may require that (1) the Partnership s initial public or private offering generate at least $140 million in net proceeds to us and (2) the Partnership raise an amount of cash (from the issuance of equity or incurrence of indebtedness) equal to $75 million minus the amount of capital expenditures it will reimburse us for from the proceeds of its initial public or private offering and to distribute that cash to us prior to, or concurrently with, the closing of its initial public or private offering. If the managing general partner sells interests to third party investors, we expect that the Partnership may at such time seek to enter into its own credit facility.

In addition, we may elect to sell our interests in the Partnership in a secondary public offering (either in connection with a public offering by the Partnership, but subject to priority rights in favor of the Partnership, or following completion of the Partnership s initial public offering, if any) or in a private placement. Neither the consent of the managing general partner nor the consent of the Partnership is required for any sale of our interests in the Partnership, other than customary blackout periods relating to offerings by the Partnership. Any proceeds raised would be for our benefit. The Partnership has granted us registration rights which will require the Partnership to register our interests with the SEC at our request from time to time (following any public offering by the Partnership), subject to various limitations and requirements.

Cash Flows

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Net cash provided by (used in):				
Operating activities	$ (22,448)	$ 3,856	$ 97,861	$ 161,490
Investing activities	(86,775)	(25,642)	(172,950)	(239,695)
Financing activities	19,442	26,026	48,471	63,604
Net increase (decrease) in cash and cash equivalents	$ (89,781)	$ 4,240	$ (26,618)	$ (14,601)

Cash Flows Provided by Operating Activities

Net cash flows from operating activities for the nine months ended September 30, 2007 was $161.5 million. The positive cash flow from operating activities generated over this period was primarily driven by favorable changes in other working capital and trade working capital, partially offset by unfavorable changes in other assets and liabilities over the period. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net loss for the nine months ended September 30, 2007 included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of September 30, 2007 (approximately two years and nine months) and the NYMEX crack spread that is the basis for the underlying swaps had increased, the unrealized losses on the Cash Flow Swap significantly decreased our Net Income over this period. The impact of these unrealized losses on the Cash Flow Swap is apparent in the $230.9 million increase in the payable to swap counterparty. Adding to our operating cash flow for the nine months ended September 30, 2007 was $38.1 million source of cash related to changes in trade working capital. For the nine months ended September 30, 2007, accounts receivable decreased $4.1 million while inventory increased by $48.4 million resulting in a net use of cash of $44.3 million. These uses of cash due to changes in trade working capital were more than offset by an increase in accounts payable, or a source of cash, of $82.4 million. The primary uses of cash during the period include a $96.4 million increase in our insurance receivable related to the flood and a $2.0 million increase in prepaid expenses and other current assets. In addition, we also reported a $36.0 million use of cash related to deferred income taxes primarily the result of the unrealized loss on the Cash Flow Swap and a $28.8 million use of cash related to accrued income taxes primarily related to the tax benefit recorded for the projected taxable loss through September 30, 2007.

Net cash flows provided by operating activities for the nine months ended September 30, 2006 was $97.9 million. The positive cash flow from operating activities during this period was primarily the result of strong operating earnings and favorable changes in other assets and liabilities offset by unfavorable changes in trade working capital and other working capital. Net income for the period was not indicative of the operating margins for the period. This was the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net income for the nine months ended September 30, 2006 included both the realized losses and the unrealized gains on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of September 30, 2006 (approximately three years and nine months years) and the NYMEX crack spread that is the basis for the underlying swaps had decreased during the period, the unrealized gains on the Cash Flow Swap increased our Net Income over this period. The impact of these unrealized gains on the Cash Flow Swap is apparent in the $88.5 million decrease in the payable to swap counterparty. Trade working capital resulted in a use of cash of $37.0 million during the nine months ended September 30, 2006 as the decrease in accounts receivable of $23.1 million was more than offset by increases in inventory of $59.8 million and a decrease in accounts payable of $0.3 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities for the nine months ended September 30, 2007 was $239.7 million compared to $173.0 million for the nine months ended September 30, 2006. The increase in investing activities for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006 was the result of increased capital expenditures associated with various capital projects in our Petroleum business.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2007 was $63.6 million as compared to net cash provided by financing activities of $48.5 million for the nine months ended September 30, 2006. The primary sources of cash for the nine months ended September 30, 2007 were obtained through net borrowings under the revolving credit facility of $20.0 million and borrowings obtained from the $25.0 million secured and the $25.0 million unsecured credit facilities obtained to provide additional liquidity during the completion of our restoration efforts for the refinery and nitrogen operations as a result of the flood. During the nine months ended September 30, 2007, we also paid $3.9 million of scheduled principal payments. For the nine months ended September 30, 2006, the primary sources of cash were the result of a $20.0 million issuance of members equity and $30.0 million of delayed draw term loans both specifically generated to fund a portion of two discretionary capital expenditures at our Petroleum operations. During the nine months ended September 30, 2006, we also paid $1.7 million of scheduled principal payments.

Working Capital

Working capital at September 30, 2007, was $(27.0) million, consisting of $576.3 million in current assets and $603.3 million in current liabilities. Working capital at December 31, 2006, was $112.3 million, consisting of $342.5 million in current assets and $230.2 million in current liabilities. In addition, we had available borrowing capacity under our 2007 Revolving Credit Facility of $168.1 million at September 30, 2007.

Letters of Credit

Our revolving credit facility provides for the issuance of letters of credit. At September 30, 2007, there were $36.9 million of irrevocable letters of credit outstanding, $3.3 million in support of certain environmental obligators, $30.6 million to secure transportation services for crude oil and $3.0 million in support for surety bonds in place to support state and federal excise tax for refined fuels.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of September 30, 2007.

Critical Accounting Policies

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

Derivative Instruments and Fair Value of Financial Instruments

We use futures contracts, options, and forward contracts primarily to reduce exposure to changes in crude oil prices, finished goods product prices and interest rates to provide economic hedges of inventory positions and anticipated interest payments on long term-debt. Although management considers these derivatives economic hedges, the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and accordingly are recorded at fair value in the balance sheet. Changes in the fair value of these derivative instruments are recorded into earnings as a component of other income (expense) in the period of change. The estimated fair values of forward and swap contracts are based on quoted market prices and assumptions for the estimated forward yield curves of related commodities in periods when quoted market prices are unavailable. The Company recorded net gains (losses) from derivative instruments of $44.7 million and $(251.9) million in gain (loss) on derivatives for the nine months ended September 30, 2006 and 2007, respectively. Net gains from derivative instruments of $171.2 million and $40.5 million were recorded for the three months ended September 30, 2006 and 2007, respectively.

As of September 30, 2007, a $1.00 change in quoted prices for the crack spreads utilized in the Cash Flow Swap would result in a $48.5 million change to the fair value of derivative commodity position and the same change to net income.

Environmental Expenditures

Liabilities related to future remediation of contaminated properties are recognized when the related costs are considered probable and can be reasonably estimated. Estimates of these costs are based upon currently available facts, existing technology, site-specific costs, and currently enacted laws of regulations. In reporting environmental liabilities, no offset is made for potential recoveries. All liabilities are monitored and adjusted as new facts or changes in law or technology occur. Environmental expenditures are capitalized when such costs provide future economic benefits. Changes in laws, regulations or assumptions used in estimating these costs could have a material impact to our financial statements. The amount recorded for environmental obligations (exclusive of estimated obligations associated with the crude oil discharge) at September 30, 2007 totaled $7.2 million, including $1.6 million included in current liabilities. Additionally, at September 30, 2007, $17.4 million was included in current liabilities for the estimated future remediation obligations arising from the crude oil discharge. This amount also included estimated obligations to settle third party property damage claims resulting from the crude oil discharge.

Share-Based Compensation

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

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

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

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

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

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

A combination of a binomial model and a probability-weighted expected return method which utilizes the company s cash flow projections was utilized to value the additional override operating units and override value units that were issued on December 28, 2006. Additionally, this combination of a binomial model and probability-weighted expected return method was utilized to value the phantom points as of December 31, 2006, March 31, 2007, and June 30, 2007. Management believed that this method was preferable for the valuation of the override units and phantom points as it allowed a better integration of the cash flows with other inputs including the timing of potential exit events that impact the estimated fair value of the override units and phantom points.

At September 30, 2007, the management common units that were subject to redemption and the phantom points were revalued through an independent appraisal process based upon a calculation utilizing the initial public offering share price.

Assuming the price of the Company s common stock increases $1.00, additional compensation expense of approximately $2.2 million would be recognized over the vesting period for phantom points.

Income Taxes

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

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

Consolidation of Variable Interest Entities

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

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

Table of Contents

Recent Accounting Developments

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of SFAS No. 115* (SFAS No. 159), which provides companies with an option to report select financial assets and liabilities at fair value. This statement also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of the 2008 fiscal year. We are in the process of evaluating the impact that adoption of SFAS No. 159 will have on our results of operations and financial condition.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157). This statement defines fair value, establishes a framework for measuring fair value and expands disclosure of fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements and accordingly, does not require any new fair value measurements. SFAS No. 157 is effective as of the beginning of the 2008 fiscal year. We are in the process of evaluating the impact that adoption of SFAS No. 157 will have on our results of operations and financial condition.

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. None of our market risk sensitive instruments are held for trading.

Commodity Price Risk

Our petroleum business, as a manufacturer of refined petroleum products, and the nitrogen fertilizer business, as a manufacturer of nitrogen fertilizer products, all of which are commodities, have exposure to market pricing for products sold in the future. In order to realize value from our processing capacity, a positive spread between the cost of raw materials and the value of finished products much be achieved (i.e., gross margin or crack spread). The physical commodities that comprise our raw materials and finished goods are typically bought and sold at a spot or index price that can be highly variable.

We use a crude oil purchasing intermediary which allows us to take title and price of our crude oil at the refinery, as opposed to the crude origination point, reducing our risk associated with volatile commodity prices by shortening the commodity conversion cycle time. The commodity conversion cycle time refers to the time elapsed between raw material acquisition and the sale of finished goods. In addition, we seek to reduce the variability of commodity price exposure by engaging in hedging strategies and transactions that will serve to protect gross margins as forecasted in the annual operating plan. Accordingly, we use financial derivatives to economically hedge future cash flows (i.e., gross margin or crack spreads) and product inventories. With regard to our hedging activities, we may enter into, or have entered into, derivative instruments which serve to:

Lock in or fix a percentage of the anticipated or planned gross margin in future periods when the derivative market offers commodity spreads that generate positive cash flows; and

Hedge the value of inventories in excess of minimum required inventories.

Further, we intend to engage only in risk mitigating activities directly related to our business.

Basis Risk. The effectiveness of our derivative strategies is dependent upon the correlation of the price index utilized for the hedging activity and the cash or spot price of the physical commodity for which price risk is being mitigated.

Basis risk is a term we use to define that relationship. Basis risk can exist due to several factors including time or location differences between the derivative instrument and the underlying physical commodity. Our selection of the appropriate index to utilize in a hedging strategy is a prime consideration in our basis risk exposure.

Examples of our basis risk exposure are as follows:

Time Basis In entering over-the counter swap agreements, the settlement price of the swap is typically the average price of the underlying commodity for a designated calendar period. This settlement price is based on the assumption that the underlying physical commodity will price ratably over the swap period. If the commodity does not move ratably over the periods than weighted average physical prices will be weighted differently than the swap price as the result of timing.

Location Basis In hedging NYMEX crack spreads, we experience location basis as the settlement of NYMEX refined products (related more to New York Harbor cash markets) which may be different than the prices of refined products in our Group 3 pricing area.

Price and Basis Risk Management Activities. Our most prevalent risk management activity is to sell forward the crack spread when opportunities exist to lock in a margin sufficient to meet our cash obligations or our operating plan. Selling forward derivative contracts for which the underlying commodity is the crack spread enables us to lock in a margin on the spread between the price of crude oil and price of refined products. The commodity derivative contracts are either exchange-traded contracts in the form of futures contracts or over-the-counter contracts in the form of commodity price swaps.

In the event our inventories exceed our target base level of inventories, we may enter into commodity derivative contracts to manage our price exposure to our inventory positions that are in excess of our base level. Excess inventories are typically the result of plant operations such as a turnaround or other plant maintenance. The commodity derivative contracts are either exchange-traded contracts in the form of futures contracts or over-the-counter contracts in the form of commodity price swaps.

To reduce the basis risk between the price of products for Group 3 and that of the NYMEX associated with selling forward derivative contracts for NYMEX crack spreads, we may enter into basis swap positions to lock the price difference. If the difference between the price of products on the NYMEX and Group 3 (or some other price benchmark as we may deem appropriate) is different than the value contracted in the swap, then we will receive from or owe to the counterparty the difference on each unit of product contracted in the swap, thereby completing the locking of our margin. An example of our use of a basis swap is in the winter heating oil season. The risk associated with not hedging the basis when using NYMEX forward contracts to fix future margins is if the crack spread increases based on prices traded on NYMEX while Group 3 pricing remains flat or decreases then we would be in a position to lose money on the derivative position while not earning an offsetting additional margin on the physical position based on the Group 3 pricing.

As of September 30, 2007, a $1.00 change in quoted futures price for the crack spreads described in the first bullet point would result in a $48.5 million change to the fair value of the derivative commodity position and the same change in net income.

Interest Rate Risk

As of September 30, 2007, all of our $821.1 million of outstanding term debt was at floating rates. An increase of 1.0% in the LIBOR rate would result in an increase in our interest expense of approximately $8.3 million per year.

As of September 30, 2007, all of our $20.0 million of outstanding revolving debt was at floating rates based on prime. If this amount remained outstanding for an entire year, an increase of 1.0% in the prime rate would result in an increase in our interest expense of approximately $0.2 million per year.

In an effort to mitigate the interest rate risk highlighted above and as required under our then-existing first and second lien credit agreements, we entered into several interest rate swap agreements in 2005. These swap agreements were entered into with counterparties that we believe to be creditworthy. Under the swap agreements, we pay fixed rates and receive floating rates based on the three-month LIBOR rates, with payments calculated on the notional amounts set for in the table below. The interest rate swaps are settled quarterly and marked to market at each reporting date.

Notional Amount	Effective Date	Termination Date	Fixed Rate
$325.0 million	6/29/07	3/30/08	4.195%
$250.0 million	3/31/08	3/30/09	4.195%
$180.0 million	3/31/09	3/30/10	4.195%
$110.0 million	3/31/10	6/29/10	4.195%

Table of Contents

We have determined that these interest rate swaps do not qualify as hedges for hedge accounting purposes. Therefore, changes in the fair value of these interest rate swaps are included in income in the period of change. Net realized and unrealized gains or losses are reflected in the gain (loss) for derivative activities at the end of each period. For the year ended December 31, 2006, we had $3.7 million of realized and unrealized gains on these interest rate swaps and for the nine months ended September 30, 2007, we had $1.4 million of realized and unrealized losses.

Item 4. ***Controls and Procedures***

(a) Evaluation of disclosure controls and procedures.

Our management has evaluated, with the participation of our principal executive and principal financial officer, the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of the end of the period covered by this report, and has concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission s rules and forms.

(c) Changes in internal control over financial reporting.

There has been no change in our internal control over financial reporting (as described in Rule 13a-15(f) under the Exchange Act) that occurred during CVR s last fiscal quarter 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***

(1) Class Action Suits

As a result of the crude oil discharge on or about July 1, 2007, two putative class action lawsuits (one federal and one state) were filed against us and/or our subsidiaries in July 2007.

(a) Federal Suit

The federal suit, Danny Dunham vs. *Coffeyville Resources, LLC, et al.,* was filed in the United States District Court for the District of Kansas at Wichita (Case No. 07-CV-01186-JTM-DWB). Plaintiff s complaint alleged that the crude oil discharge resulted from our negligent operation of the refinery and that class members suffered unspecified damages, including damages to their personal and real property, diminished property value, lost full use and enjoyment of their property, lost or diminished business income and comprehensive remediation costs. The federal suit sought recovery under the federal Oil Pollution Act, Kansas statutory law imposing a duty of compensation on a party that releases any material detrimental to the soil or waters of Kansas, and the Kansas common law of negligence, trespass and nuisance. This suit was dismissed on November 6, 2007 for lack of subject matter jurisdiction. Under the Class Action Fairness Act of 2005, a court must decline jurisdiction if two-thirds or more of the members of all proposed plaintiff classes in the aggregate, and the primary defendants, are citizens of the state in which the action was originally filed. The suit was dismissed for lack of subject matter jurisdiction because the court determined that two-thirds or more of the members of all proposed plaintiff classes in the aggregate, and the primary defendants, were citizens of Kansas.

It is possible that the plaintiffs in the federal suit may appeal the dismissal in federal court or take other actions to continue their claims, in which case, we plan on vigorously defending against such claims. Due to the uncertainty of such claims, we are unable to estimate a range of possible loss at this time. Presently, we do not expect that the resolution of these claims will have a significant adverse effect on our business and results of operations.

Table of Contents

(b) State Suit

The state suit, Western Plains Alliance, LLC and Western Plains Operations, LLC v. Coffeyville Resources Refining & Marketing, LLC, was filed in the District Court of Montgomery County, Kansas (case number 07CV99I). This suit seeks class certification under applicable law. The proposed class consists of all persons and entities who own or have owned real property within the contaminated area, and all businesses and/or other entities located within the contaminated area. To date no class has yet been certified, and any class, if certified, may be broader, narrower, or different than the class currently proposed. The Court conducted an evidentiary hearing on the issue of class certification on October 24 and 25, 2007 and a decision on whether a class will be certified is expected in the near future.

The state suit alleges that the class has suffered damages, including damages to real and personal property, decreases in property values, decreases in business revenues, loss of the right to the full and exclusive use of real property, increased costs for maintenance and upkeep, and costs for monitoring, detection, management and removal of the crude oil. The suit asserts claims against us related to negligence, nuisance and trespass. The complaint also alleges that we have a duty under Kansas statutory law to compensate owners of property affected by the release or discharge of contamination. The suit seeks unspecified damages as well as injunctive relief requiring us to take such steps as are reasonably necessary to prevent the further migration of the crude oil and for the remediation and/or removal of the crude oil. We have filed an answer in the state suit denying any liability for negligence, nuisance and trespass, while acknowledging that plaintiffs property damages and losses resulting from the oil release (but not from the flood) are properly compensable pursuant to Kansas state law if plaintiffs did not contribute to such contamination.

We intend to defend against the state suit vigorously. Due to the uncertainty of this suit, we are unable to estimate a range of possible loss at this time. Presently, we do not expect that the resolution of the state suit or both the state and federal suits will have a significant adverse effect on our business and results of operations.

(2) EPA Administrative Order on Consent

On July 10, 2007, we entered into an administrative order on consent (the Consent Order) with the United States Environmental Protection Agency (the EPA). As set forth in the Consent Order, the EPA concluded that the discharge of oil from our refinery caused and may continue to cause an imminent and substantial threat to the public health and welfare. Pursuant to the Consent Order, we agreed to perform specified remedial actions to respond to the discharge of crude oil from our refinery.

Item 1A. *Risk Factors*

The Company has included Risk Factors as Exhibit 99.1 to this Form 10-Q.

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

Use of Proceeds

On October 22, 2007 the SEC declared effective our registration statements on Form S-1 (Registration Nos. 333-137588) related to our sale of 23,000,000 shares of our common stock. On October 26, 2007, we completed an initial public offering of 23,000,000 shares at a price of $19.00 per share for an aggregate offering price of approximately $437.0 million. Of the aggregate gross proceeds, approximately $11.4 million was used to pay offering expenses related to the initial public offering, and $28.5 million was used to pay underwriting discounts and commissions. None of the expenses incurred and paid by us in this offering were direct or indirect payment (i) to our directors, officers, general partners or their associates, (ii) to persons owning 10% or more of any class of our equity securities, or (iii) to our affiliates. Net proceeds of the offering after payment of expenses and underwriting discounts and commission were approximately $397.1 million.

The offering was made through an underwriting syndicate let by Goldman, Sachs & Col, Deutsch Bank Securities, Credit Suisse, and Simmons & Company International as joint book-running managers.

Table of Contents

As of November 30, 2007, we used the net proceeds from the offering as follows:

Payment of term debt of $280.0 million and related interest of approximately $5.7 million;

Repayment of $25 million under the unsecured credit facility and repayment of $25.0 million under the secured facility including related interest of approximately $.2 million;

Repayment of revolver borrowings of $50.0 million;

Payment of a $5.0 termination fee to each of Goldman, Sachs & Co. and Kelso & Company, L.P. in connection with the termination of the management agreements in conjunction with the initial public offering; and

$1.2 million was used for general corporate purposes.

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

On October 16, 2007, our stockholders, consisting of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, consented to the following actions by written consent:

The election of the current members of our board of directors, effective as of October 16, 2007;

The adoption of our Amended and Restated Certificate of Incorporation, dated October 16, 2007, and our Amended and Restated By-Laws;

The adoption of the CVR Energy, Inc. 2007 Long Term Incentive Plan;

The grant of options to purchase 5,150 shares of our common stock to each of Messrs. Regis B. Lippert and Mark Tomkins;

The grant of 5,000 shares of restricted stock to Mr. Lippert and the grant of 12,500 shares of restricted stock to Mr. Tomkins; and

The grant of 50 shares of our common stock to 542 of our employees.

Item 6. ***Exhibits***

Number	Exhibit Title
10.1	Amended and Restated Certificate of Incorporation of CVR Energy, Inc., dated October 16, 2007.
10.2	Amended and Restated By-Laws of CVR Energy, Inc.
10.3	Amended and Restated Recapitalization Agreement, dated as of October 16, 2007, by and among Coffeyville Acquisition LLC, Coffeyville Refining & Marketing Holdings, Inc., Coffeyville Refining & Marketing, Inc., Coffeyville Nitrogen Fertilizers, Inc. and CVR Energy, Inc.
10.4	First Amended and Restated Limited Partnership Agreement of CVR Partners, LP, dated as of October 24, 2007, by and among CVR GP, LLC, CVR Special GP, LLC and Coffeyville Resources, LLC.
10.5	Coke Supply Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC.

10.6	Cross Easement Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC.
10.7	Environmental Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC.
10.8	Feedstock and Shared Services Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC.
10.9	Raw Water and Facilities Sharing Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC.
10.10	Services Agreement, dated as of October 25, 2007, by and among CVR Partners, LP, CVR GP, LLC, CVR Special GP, LLC, and CVR Energy, Inc.

Number	Exhibit Title
10.11	Omnibus Agreement, dated as of October 24, 2007 by and among CVR Energy, Inc., CVR GP, LLC, CVR Special GP, LLC and CVR Partners, LP.
10.12	Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II).
10.13	CVR Energy, Inc. 2007 Long Term Incentive Plan.
10.14	Third Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition LLC, dated as of October 16, 2007.
10.15	Amendment No. 1 to the Third Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition LLC, dated as of October 24, 2007.
10.16	First Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition II LLC, dated as of October 16, 2007.
10.17	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition II LLC, dated as of October 24, 2007.
10.18	Limited Liability Company Agreement of Coffeyville Acquisition III LLC, dated as of October 16, 2007.
10.19	Redemption Agreement, dated as of October 16, 2007, by and among Coffeyville Acquisition LLC and the Redeemed Parties signatory thereto.
10.20	Stockholders Agreement of CVR Energy, Inc., dated as of October 16, 2007, by and among CVR Energy, Inc., Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC.
10.21	Registration Rights Agreement, dated as of October 16, 2007, by and among CVR Energy, Inc., Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC.
10.22	Subscription Agreement, dated as of October 16, 2007, by and between CVR Energy, Inc. and John J. Lipinski.
10.23	Letter Agreement, dated as of October 24, 2007, by and among Coffeyville Acquisition LLC, Goldman, Sachs & Co. and Kelso & Company, L.P.
10.24	Registration Rights Agreement, dated as of October 24, 2007, by and among CVR Partners, LP, CVR Special GP, LLC and Coffeyville Resources, LLC.
10.25	CVR Partners, LP Profit Bonus Plan.
10.26	Contribution, Conveyance and Assumption Agreement, dated as of October 24, 2007, by and among Coffeyville Resources, LLC, CVR GP, LLC, CVR Special GP, LLC, and CVR Partners, LP.
10.27	Management Registration Rights Agreement, dated as of October 16, 2007, by and between CVR Energy, Inc. and John J. Lipinski.
10.28	Amendment Number 2 to Employment Agreement, dated as of October 16, 2007, by and between Coffeyville Resources, LLC and John J. Lipinski, Stanley A. Riemann, James T. Rens, Robert W. Haugen, and Wyatt E. Jernigan, respectively.
31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1	Section 1350 Certification of Chief Executive Officer.
99.1	Risk Factors.

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, this sixth day of December 2007.

CVR Energy, Inc.

	By: /s/ John J. Lipinski
Chief Executive Officer (Principal Executive Officer)	
	By: /s/ James T. Rens
Chief Financial Officer (Principal Financial Officer)	