Core-Mark Holding Company, Inc.
Form 10-Q
May 07, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
(MARK ONE)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2015
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: 000-51515
Core-Mark Holding Company, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-1489747 (IRS Employer Identification No.)
395 Oyster Point Boulevard, Suite 415 South San Francisco, CA	94080
(Address of principal executive offices)	(Zip Code)

(650) 589-9445
(Registrant’s telephone number, including area code)

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

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

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

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

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

As of April 30, 2015, 23,092,552 shares of the registrant’s common stock, $0.01 par value per share, were outstanding.

FORM 10-Q
FOR THE QUARTER ENDED MARCH 31, 2015
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PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

CORE-MARK HOLDING COMPANY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(In millions, except share and per share data)
(Unaudited)

	March 31, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$16.5	$14.4
Restricted cash	11.0	13.0
Accounts receivable, net of allowance for doubtful accounts of $10.7 and $10.8 as of March 31, 2015 and December 31, 2014, respectively	253.3	245.3
Other receivables, net	60.9	61.5
Inventories, net (Note 4)	296.9	417.8
Deposits and prepayments	56.9	43.7
Deferred income taxes	9.2	8.4
Total current assets	704.7	804.1
Property and equipment, net	147.6	148.9
Goodwill	22.9	22.9
Other intangible assets, net	24.1	22.6
Other non-current assets, net	31.1	31.1
Total assets	$930.4	$1,029.6
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$140.3	$128.4
Book overdrafts	22.9	29.1
Cigarette and tobacco taxes payable	147.2	187.3
Accrued liabilities	83.7	93.4
Deferred income taxes	0.2	0.3
Total current liabilities	394.3	438.5
Long-term debt (Note 5)	16.0	68.2
Deferred income taxes	16.3	16.2
Other long-term liabilities	11.2	11.9
Claims liabilities	27.7	27.5
Pension liabilities	5.9	6.0
Total liabilities	471.4	568.3
Commitments and contingencies (Note 6)		
Stockholders' equity:		
Common stock, $0.01 par value (50,000,000 shares authorized, 25,957,131 and 25,847,269 shares issued; 23,141,080 and 23,080,110 shares outstanding at March 31, 2015 and December 31, 2014, respectively)	0.3	0.3
Additional paid-in capital	264.6	263.8
Treasury stock at cost (2,816,051 and 2,767,159 shares of common stock at March 31, 2015 and December 31, 2014, respectively)	(55.6)	(52.6)
Retained earnings	263.9	261.4
Accumulated other comprehensive loss	(14.2)	(11.6)

Total stockholders’ equity	459.0	461.3
Total liabilities and stockholders’ equity	$930.4	$1,029.6

See accompanying notes to condensed consolidated financial statements.

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CORE-MARK HOLDING COMPANY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per share data)
(Unaudited)

	Three Months Ended March 31,	
	2015	2014
Net sales	$2,452.3	$2,300.9
Cost of goods sold	2,315.0	2,176.5
Gross profit	137.3	124.4
Warehousing and distribution expenses	79.5	75.3
Selling, general and administrative expenses	47.3	43.9
Amortization of intangible assets	0.6	0.6
Total operating expenses	127.4	119.8
Income from operations	9.9	4.6
Interest expense	(0.6)	(0.7)
Interest income	0.2	0.1
Foreign currency transaction losses, net	(0.4)	—
Income before income taxes	9.1	4.0
Provision for income taxes (Note 7)	(3.6)	(1.6)
Net income	$5.5	$2.4
Basic net income per common share (Note 9)	$0.24	$0.11
Diluted net income per common share (Note 9)	$0.24	$0.10
Basic weighted-average shares (Note 9)	23.2	23.0
Diluted weighted-average shares (Note 9)	23.3	23.2
Dividends declared and paid per common share (Note 11)	$0.13	$0.11

See accompanying notes to condensed consolidated financial statements.

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CORE-MARK HOLDING COMPANY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Three Months Ended March 31,	
	2015	2014
Net income	$5.5	$2.4
Other comprehensive loss, net of tax:		
Defined benefit plan adjustments	0.1	—
Foreign currency translation loss	(2.7)	(1.3)
Other comprehensive loss, net of tax	(2.6)	(1.3)
Comprehensive income	$2.9	$1.1

See accompanying notes to condensed consolidated financial statements.

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CORE-MARK HOLDING COMPANY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)
(Unaudited)

	Three Months Ended March 31, 2015	2014
Cash flows from operating activities:		
Net income	$5.5	$2.4
Adjustments to reconcile net income to net cash provided by operating activities:		
LIFO and inventory provisions	2.4	2.7
Amortization of debt issuance costs	0.1	0.1
Stock-based compensation expense	1.9	1.3
Bad debt expense, net	0.5	0.3
Depreciation and amortization	8.7	7.2
Foreign currency transaction losses, net	0.4	—
Deferred income taxes	(0.7)	—
Changes in operating assets and liabilities:		
Accounts receivable, net	(6.2)	(7.4)
Other receivables, net	0.1	7.8
Inventories, net	116.9	84.9
Deposits, prepayments and other non-current assets	(14.0)	5.4
Excess tax deductions associated with stock-based compensation	(1.9)	(0.7)
Accounts payable	13.4	7.2
Cigarette and tobacco taxes payable	(36.1)	(28.9)
Pension, claims, accrued and other long-term liabilities	(8.9)	(4.7)
Net cash provided by operating activities	82.1	77.6
Cash flows from investing activities:		
Acquisition of business, net of cash acquired	(8.0)	(0.1)
Change in restricted cash	2.0	1.4
Additions to property and equipment, net	(2.7)	(5.0)
Capitalization of software and related development costs	(1.9)	(0.2)
Proceeds from sale of fixed assets	0.3	—
Net cash used in investing activities	(10.3)	(3.9)
Cash flows from financing activities:		
Repayments under revolving credit facility, net	(54.9)	(46.3)
Dividends paid	(3.1)	(2.6)
Payments on capital leases	(0.6)	(0.3)
Repurchases of common stock	(3.0)	(3.0)
Proceeds from exercise of common stock options	0.3	0.7
Tax withholdings related to net share settlements of restricted stock units	(3.1)	(0.8)
Excess tax deductions associated with stock-based compensation	1.9	0.7
Decrease in book overdrafts	(6.2)	(14.4)
Net cash used in financing activities	(68.7)	(66.0)
Effects of changes in foreign exchange rates	(1.0)	(0.2)
Change in cash and cash equivalents	2.1	7.5
Cash and cash equivalents, beginning of period	14.4	11.0
Cash and cash equivalents, end of period	$16.5	$18.5
Supplemental disclosures:		

Cash paid (refunded) during the period for:		
Income taxes, net	$0.8	$(2.9)
Interest	$0.3	$0.3
Non-cash capital lease obligations incurred	$5.2	$3.5
Unpaid property and equipment purchases included in accrued liabilities	$0.4	$3.4

See accompanying notes to condensed consolidated financial statements.

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CORE-MARK HOLDING COMPANY, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Company Information

Business

Core-Mark Holding Company, Inc. and subsidiaries (referred to herein as “the Company” or “Core-Mark”) is one of the largest marketers of fresh and broad-line supply solutions to the convenience retail industry in North America. The Company offers a full range of products, marketing programs and technology solutions to approximately 35,000 customer locations in the United States (“U.S.”) and Canada. The Company’s customers include traditional convenience stores, drug stores, grocery stores, liquor stores and other specialty and small format stores that carry convenience products. The Company’s product offering includes cigarettes, other tobacco products, candy, snacks, fast food, groceries, fresh products, dairy, bread, beverages, general merchandise and health and beauty care products. The Company operates a network of 29 distribution centers in the U.S. and Canada (excluding two distribution facilities it operates as a third party logistics provider). Twenty-five of the Company’s distribution centers are located in the U.S. and four are located in Canada.

2. Basis of Presentation and Principles of Consolidation

The accompanying unaudited condensed consolidated balance sheet as of March 31, 2015, the unaudited condensed consolidated statements of operations, comprehensive income and cash flows for the three months ended March 31, 2015 and 2014, have been prepared on the same basis as the Company’s audited consolidated financial statements and include all adjustments necessary for the fair presentation of its consolidated results of operations, financial position, comprehensive income and cash flows. Results for the interim periods are not necessarily indicative of results to be expected for the full year or any other future periods. The condensed consolidated balance sheet as of December 31, 2014 has been derived from the Company’s audited financial statements, which are included in its 2014 Annual Report on Form 10-K, filed with the Securities and Exchange Commission (“SEC”) on March 2, 2015.

The significant accounting policies and certain financial information that are normally included in financial statements prepared in accordance with accounting principles generally accepted in the U.S. (“GAAP”), but which are not required for interim reporting purposes, have been omitted. The unaudited condensed consolidated interim financial statements should be read in conjunction with the Company’s audited consolidated financial statements in its Annual Report on Form 10-K, for the year ended December 31, 2014.

The unaudited condensed consolidated financial statements include Core-Mark and its wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated in the unaudited condensed consolidated financial statements. Certain prior year amounts in the unaudited condensed consolidated financial statements have been reclassified to conform to the current year’s presentation.

Shares and per share amounts for the three months ended March 31, 2014 in the accompanying condensed consolidated financial statements and applicable disclosures have been adjusted to reflect the two-for-one stock split in the form of a dividend effective June 27, 2014.

Concentration of Credit Risks

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist principally of cash investments, accounts receivable and other receivables. The Company places its cash and cash equivalents in short-term instruments with high quality financial institutions and limits the amount of credit exposure in any one financial instrument. The Company pursues amounts and incentives due from vendors in the normal course of business and is often allowed to deduct these amounts and incentives from payments made to vendors.

A credit review is completed for new customers and ongoing credit evaluations of each customer’s financial condition are performed periodically, with reserves maintained for potential credit losses. Credit limits given to customers are based on a risk assessment of their ability to pay and other factors. Accounts receivable are typically not collateralized, but the Company may require prepayments or other guarantees whenever deemed necessary.

Alimentation Couche-Tard, Inc. (“Couche-Tard”), the Company’s largest customer, accounted for approximately 14.5% and 14.6% of the Company’s total net sales for three months ended March 31, 2015 and 2014, respectively. No single customer accounted for 10% or more of the Company’s accounts receivables as of March 31, 2015 or December 31, 2014.

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Recent Accounting Standards or Updates Not Yet Effective

On May 28, 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers: Topic 606 ("ASU 2014-09"), to supersede nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration that is expected to be received for those goods or services. On April 29, 2015, the FASB issued a proposed ASU that would defer the effective date of the new revenue recognition standard by one year. The FASB also proposed permitting early adoption of the standard, but not before the original effective date which is for annual reports beginning after December 15, 2016. The Company is currently evaluating the impact of the adoption of ASU 2014-09 on its financial statements.

On June 19, 2014, the FASB issued ASU No. 2014-12, Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period: Topic 718 ("ASU 2014-12"). The standard states that a performance target in a share-based payment that affects vesting and that could be achieved after the requisite service period should be accounted for as a performance condition. This standard is effective for the Company beginning in 2016 and early adoption is permitted. The Company is currently evaluating the impact of the adoption of ASU 2014-12 on its financial statements.

On April 7, 2015, the FASB issued ASU No. 2015-03, Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs: Subtopic 835-30 ("ASU 2015-03"). In order to simplify the presentation of debt issuance costs, ASU 2015-03 requires debt issuance costs to be presented on the balance sheet as a direct deduction from the related debt liability rather than an asset. ASU 2015-03 is effective for public companies for annual periods beginning after December 15, 2015, and interim periods thereafter, with early adoption permitted. The guidance also requires retrospective application to all prior periods presented. The Company is currently evaluating the impact of the adoption of ASU 2015-03 on its financial statements.

3. Acquisition

Asset Acquisition of Karrys Bros., Limited.

On February 23, 2015, the Company acquired substantially all of the assets of Karrys Bros., Limited ("Karrys Bros."), a regional convenience wholesaler servicing customers in Ontario, Canada, and the surrounding provinces, for cash consideration of approximately $8.0 million, or $10.0 million Canadian dollars. The Karrys Bros. operations will be integrated into the Company's existing distribution center in Toronto and has provided the Company the opportunity to increase its market share in eastern Canada. The purchase price allocation of the acquired assets and liabilities assumed, based on a preliminary estimate of their fair values at the acquisition date, was as follows (in millions):

	February 23, 2015
Accounts receivable	$3.9
Inventory	3.9
Property and equipment	2.3
Liabilities	(2.1)
Total consideration	$8.0

Transaction costs in connection with the acquisition of Karrys Bros. were approximately $0.3 million for the quarter ended March 31, 2015. The results of operations of Karrys Bros. have been included in the Company's consolidated statements of operations and comprehensive income since the acquisition date. The Company did not consider the Karrys Bros. acquisition to be a material business combination and therefore has not disclosed pro-forma results of operations for the acquired business.

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4. Inventories

Inventories consist of the following (in millions):

	March 31, 2015	December 31, 2014
Inventories at FIFO, net of reserves	$414.6	$533.1
Less: LIFO reserve	(117.7)	(115.3)
Total inventories at LIFO, net of reserves	$296.9	$417.8

Cost of goods sold reflects the application of the last-in, first-out ("LIFO") method of valuing inventories in the U.S. based upon estimated annual producer price indices. Inventories in Canada are valued on a first-in, first-out ("FIFO") basis, as LIFO is not a permitted inventory valuation method in Canada. During periods of rising prices, the LIFO method of costing inventories generally results in higher current costs being charged against income while lower costs are retained in inventories. Conversely, during periods of decreasing prices, the LIFO method of costing inventories generally results in lower current costs being charged against income and higher stated inventories. The Company recorded LIFO expense of $2.4 million and $2.8 million for the three months ended March 31, 2015 and 2014, respectively.

5. Long-term Debt

Long-term debt consists of the following (in millions):

	March 31, 2015			December 31, 2014	
Amounts borrowed (Credit Facility)	$1.0			$55.9	
Obligations under capital leases	$300		June 2011	$—	$100
Revolver		$2,400	November 2012	$80	$399
Canadian revolving credit facility		C$115	December 2012	C$20	C$20

We anticipate that we will be able to renew or replace the June 2011 credit facilities prior to their expiration.

As of March 31, 2011 and December 31, 2010, we had $329 million and $176 million, respectively, of letters of credit outstanding under our uncommitted short-term bank credit facilities.

Accounts Receivable Sales Facility

We have an accounts receivable sales facility with a group of third-party entities and financial institutions to sell on a revolving basis up to $1 billion of eligible trade receivables. We amended our agreement in June 2010 to extend the maturity date to June 2011. As of March 31, 2011 and December 31, 2010 the amount of eligible receivables sold was $100 million. There were no sales or repayments of eligible receivables during the three months ended March 31, 2011. During the three months ended March 31, 2010, we sold and repaid $1.2 billion of eligible receivables to the third-party entities and financial institutions. Proceeds from the sale of receivables under this facility are reflected as debt. We anticipate that we will be able to renew this facility prior to its expiration in June 2011.

Other Disclosures

The estimated fair value of our debt, including the current portion, was as follows (in millions):

	March 31, 2011	December 31, 2010
Carrying amount (excluding capital leases)	$7,793	$8,300
Fair value	8,872	9,492

The carrying amount of our debt is the amount of debt that is reflected on our consolidated balance sheets. The fair value of that debt is based on quoted prices in active markets or quoted prices for debt of other companies with similar credit ratings, interest rates, and terms.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. COMMITMENTS AND CONTINGENCIES

Environmental Matters
While debate continues in the U.S. Congress regarding greenhouse gas legislation, the regulation of greenhouse gases at the federal level has now shifted to the U.S. Environmental Protection Agency (EPA), which began regulating greenhouse gases on January 2, 2011 under the Clean Air Act Amendments of 1990 (Clean Air Act). According to statements by the EPA, any new construction or material expansions will require that, among other things, a greenhouse gas permit be issued at either or both the state or federal level in accordance with the Clean Air Act and regulations, and we will be required to undertake a technology review to determine appropriate controls to be implemented with the project in order to reduce greenhouse gas emissions. The determination will be on a case by case basis, and the EPA has provided only general guidance on which controls will be required. Any such controls, however, could result in material increased compliance costs, additional operating restrictions for our business, and an increase in the cost of the products we produce, which could have a material adverse effect on our financial position, results of operations, and liquidity.

In addition, certain states have pursued independent regulation of greenhouse gases at the state level. For example, the California Global Warming Solutions Act, also known as AB 32, directs the California Air Resources Board (CARB) to develop and issue regulations to reduce greenhouse gas emissions in California to 1990 levels by 2020. CARB has issued a variety of regulations aimed at reaching this goal, including a Low Carbon Fuel Standard (LCFS) as well as a state-wide cap-and-trade program. The LCFS is effective in 2011, with small reductions in the carbon intensity of transportation fuels sold in California. The mandated reductions in carbon intensity are scheduled to increase through 2020, after which another step-change in reductions is anticipated. The LCFS is designed to encourage substitution of traditional petroleum fuels, and, over time, it is anticipated that the LCFS will lead to a greater use of electric cars and alternative fuels, such as E85, as companies seek to generate more credits to offset petroleum fuels. The state-wide cap-and-trade program will begin in 2012. Initially, the program will apply only to stationary sources of greenhouse gases (e.g., refinery and power plant greenhouse gas emissions). Greenhouse gas emissions from fuels that we sell in California will be covered by the program beginning in 2015. We anticipate that free allocations of credits will be available in the early years of the program, but we expect that compliance costs will be significant, particularly beginning in 2015, when fuels are included in the program. Complying with AB 32, including the LCFS and the cap-and-trade program, could result in material increased compliance costs for us, increased capital expenditures, increased operating costs, and additional operating restrictions for our business, resulting in an increase in the cost of, and decreases in the demand for, the products we produce. To the degree we are unable to recover these increased costs, these matters could have a material adverse effect on our financial position, results of operations, and liquidity.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Litigation Matters
Retail Fuel Temperature Litigation
In 2006, a class action complaint was filed against us and several other defendants engaged in the retail and wholesale petroleum marketing business. The complaint alleges that because fuel volume increases with fuel temperature, the defendants violated state consumer protection laws by failing to adjust the volume or price of fuel when the fuel temperature exceeded 60 degrees Fahrenheit. The complaints seek to certify classes of retail consumers who purchased fuel in various locations. The complaints seek an order compelling the installation of temperature correction devices as well as monetary relief. Following the 2006 complaint, numerous other federal complaints were filed, and there are now a total of 46 lawsuits of which 21 involve us. (We are named in classes involving several states where we have no retail presence.) The lawsuits are consolidated into a multi-district litigation case in the U.S. District Court for the District of Kansas (Kansas City) (Multi-District Litigation Docket No. 1840, In re: Motor Fuel Temperature Sales Practices Litigation). In May 2010, the court issued an order in response to the plaintiffs’ motion for class certification of the Kansas cases. The court certified an “injunction class” covering nonmonetary relief but deferred ruling on a “damages class.” The court has scheduled trial in the Kansas cases for May 2012. We anticipate that the non-Kansas cases will be remanded in late 2011 or early 2012 with no additional rulings on the merits or class certification. We are a party to the Kansas cases, but we have no company-owned retail locations in Kansas. We believe that we have several strong defenses to these lawsuits and intend to contest them. We have not recorded a loss contingency liability with respect to this matter, but due to the inherent uncertainty of litigation, we believe that it is reasonably possible that we may suffer a loss with respect to one or more of the lawsuits. An estimate of the possible loss or range of loss from an adverse result in all or substantially all of these cases cannot reasonably be made.

Other Litigation
We are also a party to additional claims and legal proceedings arising in the ordinary course of business. We believe that there is only a remote likelihood that future costs related to known contingent liabilities related to these legal proceedings would have a material adverse impact on our consolidated results of operations or financial position.

7. STOCKHOLDERS’ EQUITY

On April 28, 2011, our board of directors declared a regular quarterly cash dividend of $0.05 per common share payable on June 15, 2011 to holders of record at the close of business on May 18, 2011.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. EMPLOYEE BENEFIT PLANS

The components of net periodic benefit cost related to our defined benefit plans were as follows for the three months ended March 31, 2011 and 2010 (in millions):

	Pension Plans		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Components of net periodic benefit cost:				
Service cost	$23	$22	$3	$3
Interest cost	21	20	6	6
Expected return on plan assets	(28)	(28)	—	—
Amortization of:				
Prior service cost (credit)	1	1	(6)	(5)
Net loss	3	—	—	1
Net periodic benefit cost	$20	$15	$3	$5

Our anticipated contributions to our pension plans during 2011 have not changed from amounts previously disclosed in our consolidated financial statements for the year ended December 31, 2010. There were no contributions made to our pension plans during the three months ended March 31, 2011. During the three months ended March 31, 2010, we contributed $50 million to our pension plans.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. EARNINGS (LOSS) PER COMMON SHARE

Earnings (loss) per common share from continuing operations were computed as follows (dollars and shares in millions, except per share amounts):

	Three Months Ended March 31,			
	2011		2010	
	Restricted Stock	Common Stock	Restricted Stock	Common Stock
Earnings (loss) per common share from continuing operations:				
Income (loss) from continuing operations		$104		$(80)
Less dividends paid:				
Common stock		28		28
Nonvested restricted stock		—		—
Undistributed earnings (loss)		$76		$(108)
Weighted-average common shares outstanding	3	566	3	562
Earnings (loss) per common share from continuing operations:				
Distributed earnings	$0.05	$0.05	$0.05	$0.05
Undistributed earnings (loss)	0.13	0.13	—	(0.19)
Total earnings (loss) per common share from continuing operations	$0.18	$0.18	$0.05	$(0.14)
Earnings (loss) per common share from continuing operations – assuming dilution:				
Income (loss) from continuing operations		$104		$(80)
Weighted-average common shares outstanding		566		562
Common equivalent shares:				
Stock options		5		—
Performance awards and unvested restricted stock		2		—
Weighted-average common shares outstanding – assuming dilution		573		562
Earnings (loss) per common share from continuing operations – assuming dilution		$0.18		$(0.14)

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reflects potentially dilutive securities (in millions) that were excluded from the calculation of "earnings (loss) per common share from continuing operations – assuming dilution" as the effect of including such securities would have been antidilutive. These potentially dilutive securities included common equivalent shares (primarily stock options), which were excluded due to the loss from continuing operations for the three months ended March 31, 2010, and stock options for which the exercise prices were greater than the average market price of our common shares during each respective reporting period.

	Three Months Ended March 31,	
	2011	2010
Common equivalent shares	—	5
Stock options	6	14

10. SEGMENT INFORMATION

The following table reflects segment activity related to continuing operations (in millions):

	Refining	Retail	Ethanol	Corporate	Total
Three months ended March 31, 2011:					
Operating revenues from external customers	$22,562	$2,684	$1,062	$—	$26,308
Intersegment revenues	1,997	—	48	—	2,045
Operating income (loss)	276	66	44	(142)	244
Three months ended March 31, 2010:					
Operating revenues from external customers	15,747	2,176	570	—	18,493
Intersegment revenues	1,508	—	55	—	1,563
Operating income (loss)	(15)	71	57	(109)	4

Total assets by reportable segment were as follows (in millions):

	March 31, 2011	December 31, 2010
Refining	$31,619	$30,363
Retail	1,978	1,925
Ethanol	996	953
Corporate	4,999	4,380
Total consolidated assets	$39,592	$37,621

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. SUPPLEMENTAL CASH FLOW INFORMATION

In order to determine net cash provided by operating activities, net income (loss) is adjusted by, among other things, changes in current assets and current liabilities as follows (in millions):

	Three Months Ended March 31, 2011	2010
Decrease (increase) in current assets:		
Receivables, net	$(1,258)	$(189)
Inventories	622	168
Income taxes receivable	(25)	830
Prepaid expenses and other	10	32
Increase (decrease) in current liabilities:		
Accounts payable	2,143	155
Accrued expenses	174	(47)
Taxes other than income taxes	(160)	(126)
Income taxes payable	97	(70)
Changes in current assets and current liabilities	$1,603	$753

The above changes in current assets and current liabilities differ from changes between amounts reflected in the applicable consolidated balance sheets for the respective periods for the following reasons:

- the amounts shown above exclude changes in cash and temporary cash investments, deferred income taxes, and current portion of debt and capital lease obligations, as well as the effect of certain noncash investing and financing activities discussed below;
- the amounts shown above exclude the current assets and current liabilities acquired in connection with the acquisitions of three ethanol plants in the first quarter of 2010;
- amounts accrued for capital expenditures and deferred turnaround and catalyst costs are reflected in investing activities when such amounts are paid;
- amounts accrued for common stock purchases in the open market that are not settled as of the balance sheet date are reflected in financing activities when the purchases are settled and paid; and
- certain differences between consolidated balance sheet changes and the changes reflected above result from translating foreign currency denominated balances at the applicable exchange rate as of each balance sheet date.

There were no significant noncash investing or financing activities for the three months ended March 31, 2011 and 2010.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash flows related to interest and income taxes were as follows (in millions):

	Three Months Ended March 31,	
	2011	2010
Interest paid in excess of amount capitalized	$77	$56
Income taxes received (paid), net	(3)	(839)

Cash flows related to the discontinued operations of the Paulsboro and Delaware City Refineries have been combined with the cash flows from continuing operations within each category in the consolidated statement of cash flows for the three months ended March 31, 2010 and are summarized as follows (in millions):

Cash used in operating activities:	
Paulsboro Refinery	$(3)
Delaware City Refinery	(12)
Cash used in investing activities:	
Paulsboro Refinery	(6)
Delaware City Refinery	—

12. FAIR VALUE MEASUREMENTS

General

A fair value hierarchy (Level 1, Level 2, or Level 3) is used to categorize fair value amounts based on the quality of inputs used to measure fair value. Accordingly, fair values determined by Level 1 inputs utilize quoted prices in active markets for identical assets or liabilities. Fair values determined by Level 2 inputs are based on quoted prices for similar assets and liabilities in active markets, and inputs other than quoted prices that are observable for the asset or liability. Level 3 inputs are unobservable inputs for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. We use appropriate valuation techniques based on the available inputs to measure the fair values of our applicable assets and liabilities. When available, we measure fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Recurring Fair Value Measurements

The tables below present information (in millions) about our financial assets and liabilities measured and recorded at fair value on a recurring basis and indicate the fair value hierarchy of the inputs utilized by us to determine the fair values as of March 31, 2011 and December 31, 2010.

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments	Total as of March 31, 2011
Assets:					
Commodity derivative contracts	$9,612	$332	$—	$(9,558)	$386
Nonqualified benefit plans	107	—	11	—	118
Liabilities:					
Commodity derivative contracts	9,242	518	—	(9,558)	202
Nonqualified benefit plans	38	—	—	—	38

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments	Total as of December 31, 2010
Assets:					
Commodity derivative contracts	$3,240	$489	$—	$(3,560)	$169
Nonqualified benefit plans	104	—	10	—	114
Liabilities:					
Commodity derivative contracts	3,097	502	—	(3,560)	39
Nonqualified benefit plans	36	—	—	—	36

The valuation methods used to measure our financial instruments at fair value are as follows:

- Commodity derivative contracts, consisting primarily of exchange-traded futures and swaps, are measured at fair value using the market approach. Exchange-traded futures are valued based on quoted prices from the exchange and are categorized in Level 1 of the fair value hierarchy. Swaps are priced using third-party broker quotes, industry pricing services, and exchange-traded curves, with appropriate consideration of counterparty credit risk, but because they have contractual terms that are not identical to exchange-traded futures instruments with a comparable market price, these financial instruments are categorized in Level 2 of the fair value hierarchy.
- The nonqualified benefit plan assets and nonqualified benefit plan liabilities categorized in Level 1 of the fair value hierarchy are measured at fair value using a market approach based on quotations from national securities exchanges. The nonqualified benefit plan assets categorized in Level 3 of the fair value hierarchy represent insurance contracts, the fair value of which is provided by the insurer.

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CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash collateral deposits of $692 million and $403 million with brokers under master netting arrangements is included in the fair value of the commodity derivatives reflected in Level 1 as of March 31, 2011 and December 31, 2010, respectively. Certain of our commodity derivative contracts under master netting arrangements include both asset and liability positions. We have elected to offset the fair value amounts recognized for multiple similar derivative instruments executed with the same counterparty, including any related cash collateral asset or obligation; however, fair value amounts by hierarchy level are presented on a gross basis in the tables above.
The following is a reconciliation of the beginning and ending balances (in millions) for fair value measurements developed using significant unobservable inputs.

	Nonqualified Benefit Plans	
	2011	2010
Three months ended March 31:		
Balance at beginning of period	$10	$10
Total gains included in earnings	1	—
Transfers in and/or out of Level 3	—	—
Balance at end of period	$11	$10
The amount of total gains included in earnings attributable to the change in unrealized gains relating to assets still held at end of period	$1	$—

Non-Recurring Fair Value Measurements
As of March 31, 2011 and December 31, 2010, there were no nonfinancial assets or liabilities that were measured and recorded at fair value on a nonrecurring basis.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. PRICE RISK MANAGEMENT ACTIVITIES

We are exposed to market risks related to the volatility in the price of commodities, interest rates and foreign currency exchange rates, and we enter into derivative instruments to manage those risks. We also enter into derivative instruments to manage the price risk on other contractual derivatives into which we have entered. The only types of derivative instruments we enter into are those related to the various commodities we purchase or produce, interest rate swaps, and foreign currency exchange and purchase contracts, as described below. All derivative instruments are recorded as either assets or liabilities measured at their fair values.

When we enter into a derivative instrument, it is designated as a fair value hedge, a cash flow hedge, an economic hedge, or a trading activity. The gain or loss on a derivative instrument designated and qualifying as a fair value hedge, as well as the offsetting loss or gain on the hedged item attributable to the hedged risk, are recognized currently in income in the same period. The effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedge is initially reported as a component of other comprehensive income and is then recorded in income in the period or periods during which the hedged forecasted transaction affects income. The ineffective portion of the gain or loss on the cash flow derivative instrument, if any, is recognized in income as incurred. For our economic hedging relationships (hedges not designated as fair value or cash flow hedges) and for derivative instruments entered into by us for trading purposes, the derivative instrument is recorded at fair value and changes in the fair value of the derivative instrument are recognized currently in income. The cash flow effects of all of our derivative contracts are reflected in operating activities in the consolidated statements of cash flows for all periods presented.

Commodity Price Risk

We are exposed to market risks related to the price of crude oil, refined products (primarily gasoline and distillate), grain (primarily corn), and natural gas used in our refining operations. To reduce the impact of price volatility on our results of operations and cash flows, we use commodity derivative instruments, including swaps, futures, and options. We use the futures markets for the available liquidity, which provides greater flexibility in transacting our hedging and trading operations. We use swaps primarily to manage our price exposure. Our positions in commodity derivative instruments are monitored and managed on a daily basis by a risk control group to ensure compliance with our stated risk management policy that has been approved by our board of directors.

For risk management purposes, we use fair value hedges, cash flow hedges, and economic hedges. In addition to the use of derivative instruments to manage commodity price risk, we also enter into certain commodity derivative instruments for trading purposes. Our objective for entering into each type of hedge or trading activity is described below.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Fair Value Hedges

Fair value hedges are used to hedge certain refining inventories and firm commitments to purchase inventories. The level of activity for our fair value hedges is based on the level of our operating inventories, and generally represents the amount by which our inventories differ from our previous year-end LIFO inventory levels.

As of March 31, 2011, we had the following outstanding commodity derivative instruments that were entered into to hedge crude oil and refined product inventories. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes in thousands of barrels).

	Notional Contract Volumes by Year of Maturity
Derivative Instrument	2011
Crude oil and refined products:	
Futures – long	3,599
Futures – short	13,767

Cash Flow Hedges

Cash flow hedges are used to hedge certain forecasted feedstock and refined product purchases, refined product sales, and natural gas purchases. The objective of our cash flow hedges is to lock in the price of forecasted feedstock, product or natural gas purchases or refined product sales at existing market prices that we deem favorable. As of March 31, 2011, we had no outstanding commodity derivative instruments that were designated as cash flow hedges.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Economic Hedges

Economic hedges are hedges not designated as fair value or cash flow hedges and are used to manage price volatility in certain (i) refinery feedstock, refined product, and corn inventories, (ii) forecasted refinery feedstock, refined product, and corn purchases, and refined product sales, and (iii) fixed-price corn purchase contracts. Our objective in entering into economic hedges is consistent with the objectives discussed above for fair value hedges and cash flow hedges. However, the economic hedges are not designated as a fair value hedge or a cash flow hedge for accounting purposes, usually due to the difficulty of establishing the required documentation at the date that the derivative instrument is entered into that would allow us to achieve “hedge deferral accounting.”

As of March 31, 2011, we had the following outstanding commodity derivative instruments that were entered into as economic hedges and commodity derivative instruments related to the physical purchase of corn at a fixed price. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes in thousands of barrels, except those identified as corn contracts that are presented in thousands of bushels).

	Notional Contract Volumes by Year of Maturity	
Derivative Instrument	2011	2012
Crude oil and refined products:		
Swaps – long	128,021	34,500
Swaps – short	127,854	34,500
Futures – long	219,361	2,655
Futures – short	212,164	5,443
Options – long	1,802	—
Options – short	1,800	—
Corn:		
Futures – long	11,795	40
Futures – short	53,545	6,190
Physical purchase contracts – long	6,407	2,144

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Trading Activities
Derivatives entered into for trading purposes represent commodity derivative instruments held or issued for trading purposes. Our objective in entering into commodity derivative instruments for trading purposes is to take advantage of existing market conditions related to commodities that we perceive as opportunities to benefit our results of operations and cash flows, but for which there are no related physical transactions.

As of March 31, 2011, we had the following outstanding commodity derivative instruments that were entered into for trading purposes. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes represent thousands of barrels, except those identified as natural gas contracts that are presented in billions of British thermal units and corn contracts that are presented in thousands of bushels).

	Notional Contract Volumes by Year of Maturity	
Derivative Instrument	2011	2012
Crude oil and refined products:		
Swaps – long	18,390	600
Swaps – short	18,045	600
Futures – long	17,042	3,608
Futures – short	16,789	3,608
Options – long	2,500	—
Options – short	2,500	—
Natural gas:		
Futures – long	2,450	—
Futures – short	2,300	—
Corn:		
Swaps – long	1,790	—
Swaps – short	6,730	—
Futures – long	1,500	20
Futures – short	1,500	20

Interest Rate Risk
Our primary market risk exposure for changes in interest rates relates to our debt obligations. We manage our exposure to changing interest rates through the use of a combination of fixed-rate and floating-rate debt. In addition, at times we have used interest rate swap agreements to manage our fixed to floating interest rate position by converting certain fixed-rate debt to floating-rate debt.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Foreign Currency Risk
We are exposed to exchange rate fluctuations on transactions entered into by our Canadian operations that are denominated in currencies other than the Canadian dollar, which is the functional currency of those operations. To manage our exposure to these exchange rate fluctuations, we use foreign currency exchange and purchase contracts. These contracts are not designated as hedging instruments for accounting purposes, and therefore they are classified as economic hedges. As of March 31, 2011, we had commitments to purchase $600 million of U.S. dollars and commitments to sell $90 million of U.S. dollars. These commitments matured on or before April 29, 2011.
Fair Values of Derivative Instruments
The following tables provide information about the fair values of our derivative instruments as of March 31, 2011 and December 31, 2010 (in millions) and the line items in the balance sheet in which the fair values are reflected. See Note 12 for additional information related to the fair values of our derivative instruments.

As indicated in Note 12, we net fair value amounts recognized for multiple similar derivative instruments executed with the same counterparty under master netting arrangements. The tables below, however, are presented on a gross asset and gross liability basis, which results in the reflection of certain assets in liability accounts and certain liabilities in asset accounts. In addition, in Note 12, we included cash collateral on deposit with or received from brokers in the fair value of the commodity derivatives; these cash amounts are not reflected in the tables below.

		Fair Value as of March 31, 2011	
	Balance Sheet Location	Asset Derivatives	Liability Derivatives
Derivatives designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$295	$398
Total		$295	$398
Derivatives not designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$8,622	$8,844
Swaps	Receivables, net	1	—
Swaps	Prepaid expenses and other	85	70
Swaps	Accrued expenses	246	419
Options	Receivables, net	3	—
Options	Accrued expenses	—	29
Total		$8,957	$9,362
Total derivatives		$9,252	$9,760

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

		Fair Value as of December 31, 2010	
	Balance Sheet Location	Asset Derivatives	Liability Derivatives
Derivatives designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$120	$183
Swaps	Prepaid expenses and other	55	39
Swaps	Accrued expenses	31	32
Total		$206	$254
Derivatives not designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$2,717	$2,914
Swaps	Prepaid expenses and other	287	277
Swaps	Accrued expenses	116	148
Options	Accrued expenses	—	6
Total		$3,120	$3,345
Total derivatives		$3,326	$3,599

Market and Counterparty Risk

Our price risk management activities involve the receipt or payment of fixed price commitments into the future. These transactions give rise to market risk, which is the risk that future changes in market conditions may make an instrument less valuable. We closely monitor and manage our exposure to market risk on a daily basis in accordance with policies approved by our board of directors. Market risks are monitored by a risk control group to ensure compliance with our stated risk management policy. Concentrations of customers in the refining industry may impact our overall exposure to counterparty risk because these customers may be similarly affected by changes in economic or other conditions. In addition, financial services companies are the counterparties in certain of our price risk management activities, and such financial services companies may be adversely affected by periods of uncertainty and illiquidity in the credit and capital markets.

As of March 31, 2011, we had net receivables related to derivative instruments of $9 million from counterparties in the refining industry and $6 million from counterparties in the financial services industry. As of December 31, 2010, we had net receivables related to derivative instruments of $4 million from counterparties in the refining industry and $21 million from counterparties in the financial services industry. These amounts represent the aggregate amount payable to us by companies in those industries, reduced by payables from us to those companies under master netting arrangements that allow for the setoff of amounts receivable from and payable to the same party. We do not require any collateral or other security to support derivative instruments into which we enter. We also do not have any derivative instruments that require us to maintain a minimum investment-grade credit rating.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Effect of Derivative Instruments on Consolidated Statements of Income and Other Comprehensive Income
The following tables provide information about the gain or loss recognized in income and other comprehensive income on our derivative instruments and the line items in the consolidated financial statements in which such gains and losses are reflected (in millions).

Derivatives in Fair Value Hedging Relationships	Location	Gain or (Loss) Recognized in Income on Derivatives		Gain or (Loss) Recognized in Income on Hedged Item		Gain or (Loss) Recognized in Income for Ineffective Portion of Derivative	
		2011	2010	2011	2010	2011	2010
Three months ended March 31:							
Commodity contracts	Cost of sales	$(91)	$(17)	$86	$16	$(5)	$(1)

For fair value hedges, no component of the derivative instruments' gains or losses was excluded from the assessment of hedge effectiveness. No amounts were recognized in income for hedged firm commitments that no longer qualify as fair value hedges.

Derivatives in Cash Flow Hedging Relationships	Gain or (Loss) Recognized in OCI on Derivatives (Effective Portion)		Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			Gain or (Loss) Recognized in Income on Derivatives (Ineffective Portion)		
	2011	2010	Location	2011	2010	Location	2011	2010
Three months ended March 31:								
Commodity contracts	$—	$(2)	Cost of sales	$—	$49	Cost of sales	$—	$—

For cash flow hedges, no component of the derivative instruments' gains or losses was excluded from the assessment of hedge effectiveness. There was no amount of cumulative after-tax gains on cash flow hedges remaining in accumulated other comprehensive income as of March 31, 2011. For the three months ended March 31, 2011 and 2010, there were no amounts reclassified from accumulated other comprehensive income into income as a result of the discontinuance of cash flow hedge accounting.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivatives Designated as Economic Hedges and Other Derivative Instruments	Location of Gain or (Loss) Recognized in Income on Derivatives	Gain or (Loss) Recognized in Income on Derivatives	
		2011	2010
Three months ended March 31:			
Commodity contracts	Cost of sales	$(299)	$(39)
Foreign currency contracts	Cost of sales	(14)	(13)
Total		$(313)	$(52)

Included in the results above for the three months ended March 31, 2011 was a $542 million pre-tax loss on commodity contracts related to the forward sales of refined products.

Derivatives Designated as Trading Activities	Location of Gain or (Loss) Recognized in Income on Derivatives	Gain or (Loss) Recognized in Income on Derivatives	
		2011	2010
Three months ended March 31:			
Commodity contracts	Cost of sales	$6	$(3)

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

CAUTIONARY STATEMENT FOR THE PURPOSE OF SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Form 10-Q, including without limitation our discussion below under the heading "OVERVIEW AND OUTLOOK," includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. You can identify our forward-looking statements by the words "anticipate," "believe," "expect," "plan," "intend," "estimate," "project," "projection," "predict," "budget," "forecast," " "target," "could," "should," "may," and similar expressions.

These forward-looking statements include, among other things, statements regarding:

- future refining margins, including gasoline and distillate margins;
- future retail margins, including gasoline, diesel, home heating oil, and convenience store merchandise margins;
- future ethanol margins;
- expectations regarding feedstock costs, including crude oil differentials, and operating expenses;
- anticipated levels of crude oil and refined product inventories;
- our anticipated level of capital investments, including deferred refinery turnaround and catalyst costs and capital expenditures for environmental and other purposes, and the effect of those capital investments on our results of operations;
- anticipated trends in the supply of and demand for crude oil and other feedstocks and refined products in the U.S., Canada, and elsewhere;
- expectations regarding environmental, tax, and other regulatory initiatives; and
- the effect of general economic and other conditions on refining, retail, and ethanol industry fundamentals.

We based our forward-looking statements on our current expectations, estimates, and projections about ourselves and our industry. We caution that these statements are not guarantees of future performance and involve risks, uncertainties, and assumptions that we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual results may differ materially from the future performance that we have expressed or forecast in the forward-looking statements. Differences between actual results and any future performance suggested in these forward-looking statements could result from a variety of factors, including the following:

- acts of terrorism aimed at either our facilities or other facilities that could impair our ability to produce or transport refined products or receive feedstocks;
- political and economic conditions in nations that consume refined products, including the United States, and in crude oil producing regions, including the Middle East and South America;
- domestic and foreign demand for, and supplies of, refined products such as gasoline, diesel fuel, jet fuel, home heating oil, and petrochemicals;
- domestic and foreign demand for, and supplies of, crude oil and other feedstocks;
- the ability of the members of the Organization of Petroleum Exporting Countries (OPEC) to agree on and to maintain crude oil price and production controls;
- the level of consumer demand, including seasonal fluctuations;
- refinery overcapacity or undercapacity;
- our ability to successfully integrate any acquired businesses into our operations;

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- the actions taken by competitors, including both pricing and adjustments to refining capacity in response to market conditions;
- the level of foreign imports of refined products;
- accidents or other unscheduled shutdowns affecting our refineries, machinery, pipelines, or equipment, or those of our suppliers or customers;
- changes in the cost or availability of transportation for feedstocks and refined products;
- the price, availability, and acceptance of alternative fuels and alternative-fuel vehicles;
- the levels of government subsidies for ethanol and other alternative fuels;
- delay of, cancellation of, or failure to implement planned capital projects and realize the various assumptions and benefits projected for such projects or cost overruns in constructing such planned capital projects;
- lower than expected ethanol margins;
- earthquakes, hurricanes, tornadoes, and irregular weather, which can unforeseeably affect the price or availability of natural gas, crude oil, grain and other feedstocks, and refined products and ethanol;
- rulings, judgments, or settlements in litigation or other legal or regulatory matters, including unexpected environmental remediation costs, in excess of any reserves or insurance coverage;
- legislative or regulatory action, including the introduction or enactment of federal, state, municipal, or foreign legislation or rulemakings, including tax and environmental regulations, such as those to be implemented under the California Global Warming Solutions Act (also known as AB32) and the EPA's regulation of greenhouse gases, which may adversely affect our business or operations;
- changes in the credit ratings assigned to our debt securities and trade credit;
- changes in currency exchange rates, including the value of the Canadian dollar relative to the U.S. dollar; and
- overall economic conditions, including the stability and liquidity of financial markets.

Any one of these factors, or a combination of these factors, could materially affect our future results of operations and whether any forward-looking statements ultimately prove to be accurate. Our forward-looking statements are not guarantees of future performance, and actual results and future performance may differ materially from those suggested in any forward-looking statements. We do not intend to update these statements unless we are required by the securities laws to do so.

All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the foregoing. We undertake no obligation to publicly release any revisions to any such forward-looking statements that may be made to reflect events or circumstances after the date of this report or to reflect the occurrence of unanticipated events.

OVERVIEW AND OUTLOOK

For the first quarter of 2011, we reported income from continuing operations of $104 million, or $0.18 per share, compared to a loss from continuing operations of $80 million, or $0.14 per share, for the first quarter of 2010. Included in these results for the first quarter 2011 was a $542 million loss ($352 million after taxes, or $0.61 per share) on commodity derivative contracts related to the forward sales of refined products. These contracts were closed and realized in the first quarter of 2011. The improvement in income from continuing operations in the first quarter of 2011 as compared to the first quarter of 2010 was primarily due to an increase in operating income of $240 million, attributable to the business segments outlined in the following table (in millions):

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	Three Months Ended March 31,		
	2011	2010	Change
Operating income (loss) by business segment:			
Refining	$276	$(15)	$291
Retail	66	71	(5)
Ethanol	44	57	(13)
Total before corporate	386	113	273
Corporate	(142)	(109)	(33)
Total	$244	$4	$240

Excluding the impact of the $542 million loss on commodity derivative contracts, operating income for the first quarter of 2011 would have been $786 million, an increase of $782 million over the comparable 2010 period, and refining operating income would have been $818 million for the first quarter of 2011, an increase of $833 million over the comparable 2010 period.

Refining operating income improved primarily due to increased margins for most of the products we produce. In addition, refining operating income benefited from wider sour crude oil differentials (which is the difference between the price of sweet crude oil and the price of sour crude oil) and the difference between the price of waterborne sweet crude oils, such as Louisiana Light Sweet and Brent, and inland sweet crude oils, such as West Texas Intermediate (WTI). Many of our refineries process sour crude oils and WTI-type crude oils and these crude oils were priced significantly below waterborne sweet crudes during the first quarter of 2011, as compared to the first quarter of 2010.

Our retail segment generated operating income of $66 million for the first quarter of 2011 compared to operating income of $71 million for the first quarter of 2010. The decrease in operating income was primarily due to higher operating expenses.

Our ethanol segment generated operating income of $44 million for the first quarter of 2011 compared to operating income of $57 million for the first quarter of 2010. The decrease in operating income was primarily due to increased operating costs related to the full quarter of operations of the three ethanol plants we acquired in the first quarter of 2010. The ethanol business is dependent on margins between ethanol and corn feedstocks and is impacted by U.S. government subsidies and biofuels (including ethanol) mandates.

On March 10, 2011, we agreed to acquire 100 percent of the stock of Chevron Limited, which owns and operates the Pembroke Refinery in Wales, United Kingdom, from a subsidiary of Chevron Corporation. Directly and through various subsidiaries, Chevron Limited also owns extensive marketing and logistics assets throughout the United Kingdom and Ireland. The purchase price for this acquisition is $730 million, plus working capital, which has an estimated value of $1 billion based on current market prices, although the final value will be determined at closing. We expect to fund the transaction from available cash and to close the transaction in the third quarter of 2011, subject to regulatory approvals.

We anticipate the U.S. and worldwide economies to continue to recover during 2011, which should have a positive affect on refined product demand. The price of crude oil, however, has increased significantly over the past several months, increasing the absolute price of refined products for our customers. We believe if this rapid and significant increase in price continues, it could be a negative offsetting affect on overall worldwide demand. The overall impact of high energy prices on the U.S. and worldwide economies and our refined product margins is uncertain, and we expect the energy markets and margins to be volatile in the near to mid-term.

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RESULTS OF OPERATIONS

The following tables highlight our results of operations, our operating performance, and market prices that directly impact our operations. The narrative following these tables provides an analysis of our results of operations.

Financial Highlights (a) (b) (c)
(millions of dollars, except per share amounts)

	Three Months Ended March 31,		
	2011	2010	Change
Operating revenues	$26,308	$18,493	$7,815
Costs and expenses:			
Cost of sales (d) (e)	24,568	17,056	7,512
Operating expenses:			
Refining	744	764	(20)
Retail (d)	162	152	10
Ethanol	95	80	15
General and administrative expenses	130	97	33
Depreciation and amortization expense:			
Refining	316	294	22
Retail	28	26	2
Ethanol	9	8	1
Corporate	12	12	—
Total costs and expenses	26,064	18,489	7,575
Operating income	244	4	240
Other income, net	17	11	6
Interest and debt expense:			
Incurred	(144)	(147)	3
Capitalized	27	20	7
Income (loss) from continuing operations before income tax expense (benefit)	144	(112)	256
Income tax expense (benefit)	40	(32)	72
Income (loss) from continuing operations	104	(80)	184
Loss from discontinued operations, net of income taxes	(6)	(33)	27
Net income (loss)	$98	$(113)	$211
Earnings (loss) per common share – assuming dilution:			
Continuing operations	$0.18	$(0.14)	$0.32
Discontinued operations	(0.01)	(0.06)	0.05
Total	$0.17	$(0.20)	$0.37

See note references on page 36.

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Operating Highlights
(millions of dollars, except per barrel and per gallon amounts)

	Three Months Ended March 31, 2011	2010	Change
Refining (a) (b):			
Operating income (loss) (e)	$276	$(15)	$291
Throughput margin per barrel (e) (f)	$7.05	$5.98	$1.07
Operating costs per barrel			
Operating expenses	3.93	4.38	(0.45)
Depreciation and amortization expense	1.66	1.68	(0.02)
Total operating costs per barrel	5.59	6.06	(0.47)
Operating income (loss) per barrel	$1.46	$(0.08)	$1.54
Throughput volumes (thousand barrels per day):			
Feedstocks:			
Heavy sour crude	372	440	(68)
Medium/light sour crude	372	385	(13)
Acidic sweet crude	72	42	30
Sweet crude	666	588	78
Residuals	249	137	112
Other feedstocks	137	118	19
Total feedstocks	1,868	1,710	158
Blendstocks and other	238	230	8
Total throughput volumes	2,106	1,940	166
Yields (thousand barrels per day):			
Gasolines and blendstocks	956	967	(11)
Distillates	695	597	98
Other products (g)	465	398	67
Total yields	2,116	1,962	154
Retail–U.S.: (d)			
Operating income	$19	$33	$(14)
Company-operated fuel sites (average)	993	989	4
Fuel volumes (gallons per day per site)	4,895	4,942	(47)
Fuel margin per gallon	$0.076	$0.108	$(0.032)
Merchandise sales	$283	$272	$11
Merchandise margin (percentage of sales)	28.3%	28.2%	0.1%
Margin on miscellaneous sales	$22	$22	$—
Operating expenses	$98	$94	$4
Depreciation and amortization expense	$19	$18	$1
Retail–Canada: (d)			
Operating income	$47	$38	$9
Fuel volumes (thousand gallons per day)	3,234	3,078	156
Fuel margin per gallon	$0.317	$0.284	$0.033
Merchandise sales	$57	$52	$5
Merchandise margin (percentage of sales)	29.7%	30.8%	(1.1)%
Margin on miscellaneous sales	$11	$10	$1
Operating expenses	$64	$58	$6
Depreciation and amortization expense	$9	$8	$1

See note references on page 36.

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Operating Highlights (continued)
(millions of dollars, except per gallon amounts)

	Three Months Ended March 31, 2011	2010	Change
Ethanol (c):			
Operating income	$44	$57	$(13)
Ethanol production (thousand gallons per day)	3,282	2,534	748
Gross margin per gallon of ethanol production	$0.50	$0.63	$(0.13)
Operating costs per gallon of ethanol production:			
Operating expenses	0.32	0.35	(0.03)
Depreciation and amortization expense	0.03	0.03	—
Total operating costs per gallon of ethanol production	0.35	0.38	(0.03)
Ethanol operating income per gallon of production	$0.15	$0.25	$(0.10)

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See note references on page 36.

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Refining Operating Highlights by Region (e) (h)
(millions of dollars, except per barrel amounts)

	Three Months Ended March 31, 2011	2010	Change
Gulf Coast:			
Operating income (loss)	$111	$(11)	$122
Throughput volumes (thousand barrels per day)	1,299	1,137	162
Throughput margin per barrel (f)	$6.45	$6.08	$0.37
Operating costs per barrel:			
Operating expenses	3.86	4.44	(0.58)
Depreciation and amortization expense	1.64	1.74	(0.10)
Total operating costs per barrel	5.50	6.18	(0.68)
Operating income (loss) per barrel	$0.95	$(0.10)	$1.05
Mid-Continent:			
Operating income (loss)	$167	$(11)	$178
Throughput volumes (thousand barrels per day)	403	363	40
Throughput margin per barrel (f)	$9.68	$5.34	$4.34
Operating costs per barrel:			
Operating expenses	3.65	4.07	(0.42)
Depreciation and amortization expense	1.44	1.60	(0.16)
Total operating costs per barrel	5.09	5.67	(0.58)
Operating income (loss) per barrel	$4.59	$(0.33)	$4.92
Northeast (a) (b):			
Operating income	$56	$38	$18
Throughput volumes (thousand barrels per day)	209	178	31
Throughput margin per barrel (f)	$7.02	$7.77	$(0.75)
Operating costs per barrel:			
Operating expenses	2.81	3.73	(0.92)
Depreciation and amortization expense	1.20	1.66	(0.46)
Total operating costs per barrel	4.01	5.39	(1.38)
Operating income per barrel	$3.01	$2.38	$0.63
West Coast:			
Operating loss	$(58)	$(31)	$(27)
Throughput volumes (thousand barrels per day)	195	262	(67)
Throughput margin per barrel (f)	$5.62	$5.20	$0.42
Operating costs per barrel:			
Operating expenses	6.15	4.97	1.18
Depreciation and amortization expense	2.81	1.54	1.27
Total operating costs per barrel	8.96	6.51	2.45
Operating loss per barrel	$(3.34)	$(1.31)	$(2.03)
Total refining operating income (loss)	$276	$(15)	$291

See note references on page 36.

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Average Market Reference Prices and Differentials (i)
(dollars per barrel, except as noted)

	Three Months Ended March 31,		
	2011	2010	Change
Feedstocks:			
Louisiana Light Sweet (LLS) crude oil	$105.02	$79.34	$25.68
LLS less West Texas Intermediate (WTI)	11.08	0.67	10.41
LLS less Alaska North Slope (ANS) crude oil	3.78	0.79	2.99
LLS less Brent crude oil	(0.39)	3.06	(3.45)
LLS less Mars crude oil	3.59	3.61	(0.02)
LLS less Maya crude oil	15.68	9.57	6.11
WTI crude oil	93.94	78.67	15.27
WTI less Mars crude oil	(7.49)	2.94	(10.43)
WTI less Maya crude oil	4.60	8.90	(4.30)
Products:			
U.S. Gulf Coast:			
Conventional 87 gasoline less LLS	3.82	6.46	(2.64)
Ultra-low-sulfur diesel less LLS	13.59	6.83	6.76
Propylene less LLS	19.50	16.94	2.56
Conventional 87 gasoline less WTI	14.90	7.13	7.77
Ultra-low-sulfur diesel less WTI	24.67	7.49	17.18
Propylene less WTI	30.58	17.61	12.97
U.S. Mid-Continent:			
Conventional 87 gasoline less WTI	15.89	6.71	9.18
Ultra-low-sulfur diesel less WTI	25.10	6.70	18.40
U.S. Northeast:			
Conventional 87 gasoline less Brent	3.94	10.28	(6.34)
Ultra-low-sulfur diesel less Brent	15.04	11.35	3.69
Conventional 87 gasoline less WTI	15.42	7.88	7.54
Ultra-low-sulfur diesel less WTI	26.52	8.95	17.57
U.S. West Coast:			
CARBOB 87 gasoline less ANS	15.36	10.70	4.66
CARB diesel less ANS	20.70	8.55	12.15
CARBOB 87 gasoline less WTI	22.66	10.58	12.08
CARB diesel less WTI	28.00	8.43	19.57
New York Harbor corn crush (dollars per gallon)	0.08	0.45	(0.37)

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See note references on page 36.

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The following notes relate to references on pages 31 through 35.

(a) In December 2010, we sold our Paulsboro Refinery to PBF Holding Company LLC. The results of operations of the Paulsboro Refinery have been presented as discontinued operations for the three months ended March 31, 2010. The refining segment and Northeast Region operating highlights exclude the Paulsboro Refinery for all periods presented.

(b) In June 2010, we sold our shutdown Delaware City Refinery assets and associated terminal and pipeline assets to PBF Energy Partners LP. The results of operations of the Delaware City Refinery have been presented as discontinued operations for the three months ended March 31, 2010. In addition, the refining segment and Northeast Region operating highlights exclude the Delaware City Refinery for all periods presented. The terminal and pipeline assets associated with the refinery were not shut down in 2009 and continued to be operated until they were sold; the results of operations of those assets are reflected in continuing operations for the three months ended March 31, 2010.

(c) We acquired three ethanol plants in the first quarter of 2010. The information presented includes the results of operations of those plants commencing on their respective acquisition dates. Two plants were purchased from ASA Ethanol Holdings, LLC and the third plant was purchased from Renew Energy LLC. Ethanol production volumes are based on total production during each period divided by actual calendar days per period.

(d) Credit card transaction processing fees incurred by our retail segment of $21 million for the three months ended March 31, 2010 have been reclassified from retail operating expenses to cost of sales. The Retail–U.S. and Retail–Canada operating highlights for the three months ended March 31, 2010 have been restated to reflect this reclassification.

(e) Cost of sales for the three months ended March 31, 2011 includes a loss of $542 million ($352 million after taxes) on commodity derivative contracts related to the forward sales of refined product. These contracts were closed and realized during the first quarter of 2011. The $542 million loss is reflected in refining segment operating income, resulting in a $2.86 reduction in refining throughput margin per barrel for the three months ended March 31, 2011, and is allocated to refining operating income (loss) by region, excluding the Northeast, based on relative throughput volumes for each region as follows: Gulf Coast- $372 million, or $3.18 per barrel; Mid-Continent- $122 million, or $3.36 per barrel; and West Coast- $48 million, or $2.71 per barrel.

(f) Throughput margin per barrel represents operating revenues less cost of sales divided by throughput volumes.

(g) Other products primarily include petrochemicals, gas oils, No. 6 fuel oil, petroleum coke, and asphalt.

(h) The regions reflected herein contain the following refineries: the Gulf Coast region includes the Corpus Christi East, Corpus Christi West, Texas City, Houston, Three Rivers, St. Charles, Aruba, and Port Arthur Refineries; the Mid-Continent region includes the McKee, Ardmore, and Memphis Refineries; the Northeast region includes the Quebec City Refinery; and the West Coast region includes the Benicia and Wilmington Refineries.

(i) Average market reference prices for Louisiana Light Sweet (LLS) crude oil, along with price differentials between the price of LLS crude oil and other types of crude oil, have been included in the table of Average Market Reference Prices and Differentials. The table also includes price differentials by region between the prices of certain products and the benchmark crude oil that provides the best indicator of product margins for each region. Prior to the first quarter of 2011, feedstock and product differentials presented herein were based on the price of West Texas Intermediate (WTI) crude oil. However, the price of WTI crude oil no longer provides a reasonable benchmark price of crude oil for all regions. Beginning in late 2010, WTI light-sweet crude oil began to price at a discount to waterborne light-sweet crude oils, such as LLS and Brent, because of increased WTI supplies resulting from greater domestic production and increased deliveries of crude oil from Canada into the Mid-Continent region. Therefore, the use of the price of WTI crude oil as a benchmark price for regions that do not process WTI crude oil is no longer reasonable.

General

Operating revenues increased 42% (or $7.8 billion) for the first quarter of 2011 compared to the first quarter of 2010 primarily as a result of higher refined product prices and higher throughput volumes between the two periods. Operating income increased $240 million and income from continuing operations before taxes increased $256 million for the first quarter of 2011 compared to amounts reported for the first quarter of 2010 primarily due to a $291 million increase in refining segment operating income discussed below.

Refining

Results of operations of our refining segment increased from an operating loss of $15 million for the first quarter of 2010 to operating income of $276 million for the first quarter of 2011. The $291 million increase in refining operating income is due to an overall improvement in refining operating results of $833 million which was offset by a $542 million loss on commodity derivative contracts related to forward sales of refined products.

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Prior to the first quarter of 2011, feedstock and product differentials presented herein were based on the price of WTI crude oil. However, the price of WTI crude oil no longer provides a reasonable benchmark price of crude oil for all regions. Beginning in late 2010, WTI light-sweet crude oil began to price at a discount to waterborne light-sweet crude oils, such as LLS and Brent, because of increased WTI supplies resulting from greater domestic production and increased deliveries of crude oil from Canada into the Mid-Continent region. Therefore, the use of the price of WTI crude oil as a benchmark price for regions that do not process WTI crude oil is no longer reasonable.

The $833 million improvement in operating results was primarily due to a 66% increase in throughput margin per barrel (a $3.93 per barrel increase between the comparable periods, consisting of the actual increase of $1.07 per barrel adjusted for the $2.86 per barrel impact of the $542 million loss discussed above) combined with a 9% increase in total throughput volumes (a 166,000 barrel per day increase between the comparable periods). The increase in throughput margin per barrel was caused by a significant improvement in LLS-based distillate margins, which was somewhat offset by a decline in LLS-based gasoline margins in two of our four refining regions. Throughput margin per barrel also benefited from significantly wider sour crude oil differentials. The impact of these factors on our throughput margin per barrel is described below.

Changes in the margin that we receive for our products have a material impact on our results of operations. For example, the LLS-based benchmark reference margin for U.S. Gulf Coast ultra-low-sulfur diesel, which is a type of distillate, was $13.59 per barrel for the first quarter of 2011, compared to $6.83 per barrel for the first quarter of 2010, representing a favorable increase of $6.76 per barrel. Similar increases in distillate margins were experienced in other regions. We estimate that the increase in margin for distillates had a $491 million positive impact to our overall refining margin, quarter versus quarter, as we produced 695,000 barrels per day of distillates during the first quarter of 2011. Distillate margins were higher in the first quarter of 2011 as compared to the first quarter of 2010 due to an increase in the industrial demand for these products resulting from the ongoing recovery of the U.S. and worldwide economies.

The LLS-based benchmark reference margin for U.S. Gulf Coast Conventional 87 gasoline (Conventional 87 gasoline) was $3.82 per barrel for the first quarter of 2011, compared to $6.46 per barrel for the first quarter of 2010, representing an unfavorable decrease of $2.64 per barrel. Conventional 87 gasoline benchmark reference margins decreased quarter versus quarter to an even greater extent in the Northeast region (a $6.34 per barrel unfavorable decrease), but the margins increased quarter versus quarter in the Mid-Continent region (a $9.18 per barrel favorable increase). We estimate that the overall decrease in gasoline margins had an $82 million negative impact to our overall refining margin, quarter versus quarter, as we produced 956,000 barrels per day of gasoline during the first quarter of 2011. Gasoline margins were lower in the U.S. Gulf Coast and Northeast regions in the first quarter of 2011 as compared to the first quarter of 2010 due to the price of gasoline increasing at a lower rate than the cost of crude oil processed in the regions. Conversely, gasoline margins were higher in the U.S. Mid-Continent and U.S. West Coast regions in the first quarter of 2011 as compared to the first quarter of 2010 due to the cost of crude oil processed in these regions (which are primarily priced relative to WTI and ANS, respectively) increasing at a lower rate than the increase in the price of gasoline. Historically, the price of WTI has closely tracked LLS. However, due to the significant development of crude oil reserves within the Mid-Continent region and increase deliveries of crude oil from Canada into the Mid-Continent region, the increased supply of WTI has resulted in WTI currently being priced at a discount to LLS.
The cost of crude oil we process also has a material impact on our results of operations because many of our refineries process sour crude oils and WTI-type crude oils, which were priced significantly below waterborne sweet crude oils, such as LLS and Brent. For example, Maya crude oil, which is a type of sour crude oil, sold at a discount of $15.68 per barrel to LLS crude oil, which is a type of sweet crude oil, during the first

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quarter of 2011. This compares to a discount of $9.57 per barrel during the first quarter of 2010, representing a favorable increase of $6.11 per barrel. We estimate that the wider discounts for all types of sour crude oil that we process had a $481 million positive impact to our overall refining margin, quarter versus quarter, as we processed 744,000 barrels per day of sour crude oils.

Retail

Retail operating income was $66 million for the first quarter of 2011 compared to $71 million for the first quarter of 2010. This 7% (or $5 million) decrease was primarily due to higher operating expenses of $10 million of which $4 million related to the strengthening of the Canadian dollar relative to the U.S. dollar in our Canadian retail operations. Higher operating expenses were partially offset by a $4 million improvement in merchandise margins between the quarters.

Ethanol

Ethanol operating income was $44 million for the first quarter of 2011 compared to $57 million for the first quarter of 2010. The $13 million decrease in operating income resulted mainly from a $15 million increase in operating expenses, partially offset by a $5 million increase in gross margin.

The increase in operating expenses was due primarily to $19 million in operating expenses related to the full quarter of operations of the three ethanol plants we acquired in the first quarter of 2010.

Ethanol gross margin increased from the first quarter of 2010 to the first quarter of 2011 due an increase in ethanol production (a 748,000 gallon per day increase between the comparable periods) primarily resulting from the full operation of three additional plants acquired in the first quarter of 2010. This increase, however, was negatively impacted by a 21% decrease in the gross margin per gallon of ethanol production (a $0.13 per gallon decrease between the comparable periods). The decrease in gross margin per gallon was primarily due to a decrease in the New York Harbor corn crush (Corn Crush), which is the benchmark reference margin for ethanol. The Corn Crush was $0.08 per gallon for the first quarter of 2011, compared to $0.45 per gallon for the first quarter of 2010, representing an unfavorable decrease of $0.37 per gallon.

Corporate Expenses and Other

General and administrative expenses increased $33 million from the first quarter of 2010 to the first quarter of 2011 primarily due to a favorable settlement with an insurance company for $40 million recorded in the first quarter of 2010, which reduced general and administration expenses in that quarter.

“Other income, net” for the first quarter of 2011 increased $6 million from the first quarter of 2010 primarily due to an increase of $4 million in interest income earned on cash held in interest-bearing accounts and $3 million in interest on the note receivable related to the sale of our Paulsboro Refinery in December 2010.

Interest and debt expense for the first quarter of 2011 decreased $10 million from the first quarter of 2010. This decrease is composed of a decrease in interest expense of $3 million primarily due to a decrease in our average cost of borrowing and a $7 million increase in capitalized interest due to a corresponding increase in capital expenditures between the quarters.

Income tax expense increased $72 million from the first quarter of 2011 to the first quarter of 2010 mainly as a result of higher operating income.

The loss from discontinued operations of $6 million for the first quarter of 2011 primarily represents adjustments to the working capital settlement related to the sale of our Paulsboro Refinery in December 2010. The loss from discontinued operations of $33 million for the first quarter of 2010 represents the discontinued operations from the Delaware City and Paulsboro Refineries.

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LIQUIDITY AND CAPITAL RESOURCES

Cash Flows for the Three Months Ended March 31, 2011 and 2010

Net cash provided by operating activities for the first three months of 2011 was $2.1 billion compared to $982 million for the first three months of 2010. The increase in cash generated from operating activities was primarily due to an $850 million favorable effect from changes in working capital between the quarters, combined with the $240 million increase in operating income discussed above under "RESULTS OF OPERATIONS." Changes in cash provided by or used for working capital during the first three months of 2011 and 2010 are shown in Note 11 of Condensed Notes to Consolidated Financial Statements.

The net cash generated from operating activities during the first three months of 2011 was used mainly to:

- fund $737 million of capital expenditures and deferred turnaround and catalyst costs;
- make a scheduled long-term note repayment of $210 million and acquire the Gulf Opportunity Zone Revenue Bonds Series 2010 for $300 million;
- pay common stock dividends of $28 million; and
- increase available cash on hand by $799 million.

The net cash generated from operating activities during the first three months of 2010, combined with $1.244 billion of proceeds from the issuance of $400 million of 4.50% notes due in February 2015 and $850 million of 6.125% notes due in February 2020 as discussed in Note 5 of Condensed Notes to Consolidated Financial Statements, were used mainly to:

- fund $611 million of capital expenditures and deferred turnaround and catalyst costs;
- redeem our 7.50% senior notes for $294 million;
- purchase additional ethanol plants for $260 million;
- pay common stock dividends of $28 million; and
- increase available cash on hand by $1.1 billion.

Cash flows related to the discontinued operations of the Paulsboro and Delaware City Refineries have been combined with the cash flows from continuing operations within each category in the consolidated statements of cash flows for the three months ended March 31, 2010 and are summarized as follows (in millions):

Cash used in operating activities:		
Paulsboro Refinery	$(3	)
Delaware City Refinery	(12	)
Cash used in investing activities:		
Paulsboro Refinery	(6	)
Delaware City Refinery	—	

Capital Investments

During the three months ended March 31, 2011, we expended $438 million for capital expenditures and $299 million for deferred turnaround and catalyst costs. Capital expenditures for the three months ended March 31, 2011 included $61 million of costs related to environmental projects.

For 2011, we expect to incur approximately $3.2 billion for capital investments, including approximately $2.6 billion for capital expenditures (approximately $260 million of which is for environmental projects) and approximately $570 million for deferred turnaround and catalyst costs. The capital expenditure estimate excludes expenditures related to strategic acquisitions. We continuously evaluate our capital budget and make changes as economic conditions warrant.

Proposed Pembroke Refinery Acquisition

On March 10, 2011, we agreed to acquire 100 percent of the stock of Chevron Limited, which owns and operates the Pembroke Refinery in Wales, United Kingdom, from a subsidiary of Chevron Corporation. Directly and through various subsidiaries, Chevron Limited also owns extensive marketing and logistics assets throughout the United Kingdom and Ireland. The purchase price for this acquisition is $730 million, plus working capital, which has an estimated value of $1 billion based on current market prices, although the final value will be determined at closing. We expect to fund the transaction from available cash and to close the transaction in the third quarter of 2011, subject to regulatory approvals.

Contractual Obligations

As of March 31, 2011, our contractual obligations included debt, capital lease obligations, operating leases, purchase obligations, and other long-term liabilities.

In February 2011, we made a scheduled debt repayment of $210 million related to our 6.75% senior notes. In February 2011, we also paid $300 million to acquire our GO Zone Bonds, which were subject to mandatory tender. On May 2, 2011, we made a scheduled debt repayment of $200 million related to our 6.125% senior notes.

We have an accounts receivable sales facility with a group of third-party entities and financial institutions to sell on a revolving basis up to $1 billion of eligible trade receivables, which matures in June 2011. As of March 31, 2011, the amount of eligible receivables sold was $100 million. We anticipate that we will be able to renew this facility prior to its expiration in June 2011.

During the three months ended March 31, 2011, we had no material changes outside the ordinary course of our business with respect to capital lease obligations, operating leases, purchase obligations, or other long-term liabilities.

Our agreements do not have rating agency triggers that would automatically require us to post additional collateral. However, in the event of certain downgrades of our senior unsecured debt to below investment grade ratings by Moody’s Investors Service and Standard & Poor’s Ratings Services, the cost of borrowings under some of our bank credit facilities and other arrangements would increase. As of May 9, 2011, all of our ratings on our senior unsecured debt are at or above investment grade level as follows:

Rating Agency	Rating
Standard & Poor’s Ratings Services	BBB (stable outlook)
Moody’s Investors Service	Baa2 (stable outlook)
Fitch Ratings	BBB (negative outlook)

We cannot provide assurance that these ratings will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell, or hold our securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction below investment grade or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to obtain short- and long-term financing and the cost of such financings.

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Other Commercial Commitments

As of March 31, 2011, our committed lines of credit were as follows (in millions):

	Borrowing Capacity	Expiration	Outstanding Letters of Credit
Letter of credit facility	$200	June 2011	$200
Letter of credit facility	$300	June 2011	$—
Revolving credit facility	$2,400	November 2012	$80
Canadian revolving credit facility	C$115	December 2012	C$20

As of March 31, 2011, we had no amounts borrowed under our revolving credit facilities. The letters of credit outstanding as of March 31, 2011 expire during 2011 and 2012. We anticipate that we will be able to renew or replace the June 2011 credit facilities prior to their expiration.

Stock Purchase Programs

As of March 31, 2011, we have approvals under common stock purchase programs previously approved by our board of directors to purchase approximately $3.5 billion of our common stock.

Other Matters Impacting Liquidity and Capital Resources

We have no minimum required contributions to our pension plans during 2011 under the Employee Retirement Income Security Act; however, we plan to contribute approximately $100 million to our pension plans during 2011.

Environmental Matters

We are subject to extensive federal, state, and local environmental laws and regulations, including those relating to the discharge of materials into the environment, waste management, pollution prevention measures, greenhouse gas emissions, and characteristics and composition of gasolines and distillates. Because environmental laws and regulations are becoming more complex and stringent and new environmental laws and regulations are continuously being enacted or proposed, the level of future expenditures required for environmental matters could increase in the future. In addition, any major upgrades in any of our refineries could require material additional expenditures to comply with environmental laws and regulations.

While debate continues in the U.S. Congress regarding greenhouse gas legislation, the regulation of greenhouse gases at the federal level has now shifted to the U.S. Environmental Protection Agency (EPA), which began regulating greenhouse gases on January 2, 2011 under the Clean Air Act Amendments of 1990 (Clean Air Act). According to statements by the EPA, any new construction or material expansions will require that, among other things, a greenhouse gas permit be issued at either or both the state or federal level in accordance with the Clean Air Act and regulations, and we will be required to undertake a technology review to determine appropriate controls to be implemented with the project in order to reduce greenhouse gas emissions. The determination will be on a case by case basis, and the EPA has provided only general guidance on which controls will be required. Any such controls, however, could result in material increased compliance costs, additional operating restrictions for our business, and an increase in the cost of the products we produce, which could have a material adverse effect on our financial position, results of operations, and liquidity.

In addition, certain states have pursued independent regulation of greenhouse gases at the state level. For example, the California Global Warming Solutions Act, also known as AB 32, directs the California Air Resources Board (CARB) to develop and issue regulations to reduce greenhouse gas emissions in California

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to 1990 levels by 2020. CARB has issued a variety of regulations aimed at reaching this goal, including a Low Carbon Fuel Standard (LCFS) as well as a state-wide cap-and-trade program. The LCFS is effective in 2011, with small reductions in the carbon intensity of transportation fuels sold in California. The mandated reductions in carbon intensity are scheduled to increase through 2020, after which another step-change in reductions is anticipated. The LCFS is designed to encourage substitution of traditional petroleum fuels, and, over time, it is anticipated that the LCFS will lead to a greater use of electric cars and alternative fuels, such as E85, as companies seek to generate more credits to offset petroleum fuels. The state-wide cap-and-trade program will begin in 2012. Initially, the program will apply only to stationary sources of greenhouse gases (e.g., refinery and power plant greenhouse gas emissions). Greenhouse gas emissions from fuels that we sell in California will be covered by the program beginning in 2015. We anticipate that free allocations of credits will be available in the early years of the program, but we expect that compliance costs will be significant, particularly beginning in 2015, when fuels are included in the program. Complying with AB 32, including the LCFS and the cap-and-trade program, could result in material increased compliance costs for us, increased capital expenditures, increased operating costs, and additional operating restrictions for our business, resulting in an increase in the cost of, and decreases in the demand for, the products we produce. To the degree we are unable to recover these increased costs, these matters could have a material adverse effect on our financial position, results of operations, and liquidity.

On June 30, 2010, the EPA formally disapproved the flexible permits program submitted by the Texas Commission on Environmental Quality (TCEQ) in 1994 for inclusion in its clean-air implementation plan. The EPA determined that Texas' flexible permit program did not meet several requirements under the federal Clean Air Act. Our Port Arthur, Texas City, Three Rivers, McKee and Corpus Christi East and West Refineries formerly operated under flexible permits administered by the TCEQ. In the fourth quarter of 2010, we completed the conversion of our flexible permits into federally enforceable conventional state NSR permits ("de-flexed permits"). We are now in the process of incorporating these de-flexed permits into our Title V permits. Continued discussions with the TCEQ and the EPA regarding this matter are likely.

Meanwhile, the EPA has formally disapproved other TCEQ permitting programs that historically have streamlined the environmental permitting process in Texas. For example, the EPA has disapproved the TCEQ pollution control standard permit, thus requiring conventional permitting for future pollution control equipment. Litigation is pending from industry groups and others against the EPA for each of these actions. The EPA has also objected to numerous Title V permits in Texas and other states, including permits at our Port Arthur, Corpus Christi East, and McKee Refineries. Environmental activist groups have filed a notice of intent to sue the EPA, seeking to require the EPA to assume control of these permits from the TCEQ. All of these developments have created substantial uncertainty regarding existing and future permitting. Because of this uncertainty, we are unable to determine the costs or effects of the EPA's actions on our permitting activity. But the EPA's disruption of the Texas permitting system could result in material increased compliance costs for us, increased capital expenditures, increased operating costs, and additional operating restrictions for our business, resulting in an increase in the cost of, and decreases in the demand for, the products we produce, which could have a material adverse effect on our financial position, results of operations, and liquidity.

Tax Matters

We are subject to extensive tax liabilities, including federal, state, and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise, withholding, and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted or proposed that could result in increased expenditures for tax liabilities in the future. Many of these liabilities are subject to periodic audits by the respective taxing authority. Subsequent changes to our tax liabilities as a result of these audits may subject us to interest and penalties.

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Financial Regulatory Reform

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (Wall Street Reform Act). The Wall Street Reform Act, among many things, creates new regulations for companies that extend credit to consumers and requires most derivative instruments to be traded on exchanges and routed through clearinghouses. Rules to implement the Wall Street Reform Act are being finalized and therefore, the impact to our operations is not yet known. However, implementation could result in higher margin requirements, higher clearing costs, and more reporting requirements with respect to our derivative activities.

Other

Our refining and marketing operations have a concentration of customers in the refining industry and customers who are refined product wholesalers and retailers. These concentrations of customers may impact our overall exposure to credit risk, either positively or negatively, in that these customers may be similarly affected by changes in economic or other conditions. However, we believe that our portfolio of accounts receivable is sufficiently diversified to the extent necessary to minimize potential credit risk. Historically, we have not had any significant problems collecting our accounts receivable.

We believe that we have sufficient funds from operations and, to the extent necessary, from borrowings under our credit facilities, to fund our ongoing operating requirements. We expect that, to the extent necessary, we can raise additional funds from time to time through equity or debt financings in the public and private capital markets or the arrangement of additional credit facilities. However, there can be no assurances regarding the availability of any future financings or additional credit facilities or whether such financings or additional credit facilities can be made available on terms that are acceptable to us.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with United States generally accepted accounting principles requires us to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates. Our critical accounting policies are disclosed in our annual report on Form 10-K for the year ended December 31, 2010, except for the addition of the policy reflected below regarding our estimates of the useful lives of our property, plant and equipment, which we have identified as a critical accounting policy.

Estimated Useful Lives of Property, Plant and Equipment

We calculate depreciation expense based on estimated useful lives and salvage values of our property, plant and equipment. When these assets are placed into service, we make estimates with respect to their useful lives that we believe are reasonable. However, factors such as competition, regulation, or environmental matters could cause us to change our estimates, thus impacting the future calculation of depreciation expense.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks related to the volatility in the price of commodities, interest rates and foreign currency exchange rates, and we enter into derivative instruments to manage those risks. We also enter into derivative instruments to manage the price risk on other contractual derivatives into which we have entered. The only types of derivative instruments we enter into are those related to the various commodities we purchase or produce, interest rate swaps, and foreign currency exchange and purchase contracts, as described below. All derivative instruments are recorded on our balance sheet as either assets or liabilities measured at their fair values.

COMMODITY PRICE RISK

We are exposed to market risks related to the price of crude oil, refined products (primarily gasoline and distillate), grain (primarily corn), and natural gas used in our refining operations. To reduce the impact of price volatility on our results of operations and cash flows, we enter into commodity derivative instruments, including swaps, futures, and options to hedge:

- inventories and firm commitments to purchase inventories generally for amounts by which our current year LIFO inventory levels differ from our previous year-end LIFO inventory levels and
- forecasted feedstock and refined product purchases, refined product sales, and natural gas purchases, and corn purchases to lock in the price of those forecasted transactions at existing market prices that we deem favorable.

We use the futures markets for the available liquidity, which provides greater flexibility in transacting our hedging and trading operations. We use swaps primarily to manage our price exposure. We also enter into certain commodity derivative instruments for trading purposes to take advantage of existing market conditions related to commodities that we perceive as opportunities to benefit our results of operations and cash flows, but for which there are no related physical transactions.

Our positions in commodity derivative instruments are monitored and managed on a daily basis by a risk control group to ensure compliance with our stated risk management policy that has been approved by our board of directors.

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The following sensitivity analysis includes all positions at the end of the reporting period with which we have market risk (in millions):

	Derivative Instruments Held For Non-Trading Purposes	Trading Purposes
March 31, 2011:		
Gain (loss) in fair value due to:		
10% increase in underlying commodity prices	$(59)	$2
10% decrease in underlying commodity prices	59	(2)
December 31, 2010:		
Gain (loss) in fair value due to:		
10% increase in underlying commodity prices	(199)	—
10% decrease in underlying commodity prices	189	(1)

See Note 13 of Condensed Notes to Consolidated Financial Statements for notional volumes associated with these derivative contracts as of March 31, 2011.

INTEREST RATE RISK

The following table provides information about our debt instruments (dollars in millions), the fair values of which are sensitive to changes in interest rates. Principal cash flows and related weighted-average interest rates by expected maturity dates are presented. We had no interest rate derivative instruments outstanding as of March 31, 2011 or December 31, 2010.

	March 31, 2011 Expected Maturity Dates							
	2011	2012	2013	2014	2015	There-after	Total	Fair Value
Debt (excluding capital lease obligations):								
Fixed rate	$208	$759	$489	$209	$484	$5,605	$7,754	$8,772
Average interest rate	6.1 %	6.9 %	5.5 %	4.8 %	5.2 %	7.2 %	6.9 %	
Floating rate	$100	$—	$—	$—	$—	$—	$100	$100
Average interest rate	0.8 %	— %	— %	— %	— %	— %	0.8 %	

	December 31, 2010 Expected Maturity Dates							
	2011	2012	2013	2014	2015	There-after	Total	Fair Value
Debt (excluding capital lease obligations):								
Fixed rate	$418	$759	$489	$209	$484	$5,605	$7,964	$9,092
Average interest rate	6.4 %	6.9 %	5.5 %	4.8 %	5.2 %	7.2 %	6.9 %	
Floating rate	$400	$—	$—	$—	$—	$—	$400	$400
Average interest rate	0.5 %	— %	— %	— %	— %	— %	0.5 %	

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FOREIGN CURRENCY RISK

We are exposed to exchange rate fluctuations on transactions entered into by our Canadian operations that are denominated in currencies other than the Canadian dollar, which is the functional currency of those operations. To manage our exposure to these exchange rate fluctuations, we use foreign currency exchange and purchase contracts. As of March 31, 2011, we had commitments to purchase $600 million of U.S. dollars and commitments to sell $90 million of U.S. dollars. Our market risk was minimal on these contracts, as they matured on or before April 29, 2011, resulting in a $7 million loss in the second quarter of 2011.

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures.

Our management has evaluated, with the participation of our principal executive officer 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) as of the end of the period covered by this report, and has concluded that our disclosure controls and procedures were effective as of March 31, 2011.

(b) Changes in internal control over financial reporting.

There has been no change in our internal control over financial reporting that occurred during our last fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

The information below describes new proceedings or material developments in proceedings that we previously reported in our annual report on Form 10-K for the year ended December 31, 2010.

Litigation

For the legal proceedings listed below, we hereby incorporate by reference into this Item our disclosures made in Part I, Item 1 of this Report included in Note 6 of Condensed Notes to Consolidated Financial Statements under the caption "Litigation Matters."

- Retail Fuel Temperature Litigation
- Other Litigation

Environmental Enforcement Matters

While it is not possible to predict the outcome of the following environmental proceedings, if any one or more of them were decided against us, we believe that there would be no material effect on our financial position or results of operations. We are reporting these proceedings to comply with SEC regulations, which require us to disclose certain information about proceedings arising under federal, state, or local provisions regulating the discharge of materials into the environment or protecting the environment if we reasonably believe that such proceedings will result in monetary sanctions of $100,000 or more.

Bay Area Air Quality Management District (BAAQMD) (Benicia Refinery). In the first quarter of 2011, we settled 28 violation notices (VN's) with the BAAQMD that were issued in 2008.

Texas Commission on Environmental Quality (TCEQ) (Three Rivers Refinery). In our annual report on Form 10-K for the year ended December 31, 2010, we disclosed a proposed agreed order from the TCEQ alleging an unauthorized discharge of wastewater at our Three Rivers Refinery. In the first quarter of 2011, we signed an agreed order to resolve this matter.

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in our annual report on Form 10-K for the year ended December 31, 2010.

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

(a) Unregistered Sales of Equity Securities. Not applicable.

(b) Use of Proceeds. Not applicable.

(c) Issuer Purchases of Equity Securities. The following table discloses purchases of shares of our common stock made by us or on our behalf for the periods shown below.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Not Purchased as Part of Publicly Announced Plans or Programs (a)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (b)
January 2011	12,146	$24.95	12,146	—	$3.46 billion
February 2011	7,023	$26.47	7,023	—	$3.46 billion
March 2011	1,864	$28.22	1,864	—	$3.46 billion
Total	21,033	$25.75	21,033	—	$3.46 billion

(a) The shares reported in this column represent purchases settled in the first quarter of 2011 relating to (a) our purchases of shares in open-market transactions to meet our obligations under employee stock compensation plans, and (b) our purchases of shares from our employees and non-employee directors in connection with the exercise of stock options, the vesting of restricted stock, and other stock compensation transactions in accordance with the terms of our incentive compensation plans.

(b) On April 26, 2007, we publicly announced an increase in our common stock purchase program from $2 billion to $6 billion, as authorized by our board of directors on April 25, 2007. The $6 billion common stock purchase program has no expiration date. On February 28, 2008, we announced that our board of directors approved a $3 billion common stock purchase program. This program is in addition to the $6 billion program. This $3 billion program has no expiration date.

Item 6. Exhibits

Exhibit No.	Description
12.01	Statements of Computations of Ratios of Earnings to Fixed Charges and Ratios of Earnings to Fixed Charges and Preferred Stock Dividends.
31.01	Rule 13a-14(a) Certification (under Section 302 of the Sarbanes-Oxley Act of 2002) of principal executive officer.
31.02	Rule 13a-14(a) Certification (under Section 302 of the Sarbanes-Oxley Act of 2002) of principal financial officer.
32.01	Section 1350 Certifications (as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
101	Interactive Data Files

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SIGNATURE

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.

VALERO ENERGY CORPORATION
(Registrant)

By: /s/ Michael S. Ciskowski
Michael S. Ciskowski
Executive Vice President and
Chief Financial Officer
(Duly Authorized Officer and Principal
Financial and Accounting Officer)

Date: May 9, 2011