VALERO ENERGY CORP/TX
Form 10-Q
August 09, 2011
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

R QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2011
OR

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

Commission file number 1-13175
VALERO ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	74-1828067
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

One Valero Way
San Antonio, Texas
(Address of principal executive offices)
78249
(Zip Code)
(210) 345-2000
(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 R 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 shorter period that the registrant was required to submit and post such files). Yes R 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 R Accelerated filer o Non-accelerated filer o 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 R

The number of shares of the registrant's only class of common stock, $0.01 par value, outstanding as of July 29, 2011 was 572,133,317.

VALERO ENERGY CORPORATION AND SUBSIDIARIES
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PART I – FINANCIAL INFORMATION
Item 1. Financial Statements

VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars, Except Par Value)

	June 30, 2011 (Unaudited)	December 31, 2010
ASSETS		
Current assets:		
Cash and temporary cash investments	$4,107	$3,334
Receivables, net	6,027	4,583
Inventories	3,988	4,947
Income taxes receivable	118	343
Deferred income taxes	285	190
Prepaid expenses and other	162	121
Total current assets	14,687	13,518
Property, plant and equipment, at cost	29,866	28,921
Accumulated depreciation	(6,660)	(6,252)
Property, plant and equipment, net	23,206	22,669
Intangible assets, net	222	224
Deferred charges and other assets, net	1,411	1,210
Total assets	$39,526	$37,621
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of debt and capital lease obligations	$861	$822
Accounts payable	7,642	6,441
Accrued expenses	765	590
Taxes other than income taxes	627	671
Income taxes payable	82	3
Deferred income taxes	254	257
Total current liabilities	10,231	8,784
Debt and capital lease obligations, less current portion	6,762	7,515
Deferred income taxes	4,801	4,530
Other long-term liabilities	1,740	1,767
Commitments and contingencies		
Equity:		
Valero Energy Corporation stockholders' equity:		
Common stock, $0.01 par value; 1,200,000,000 shares authorized; 673,501,593 and 673,501,593 shares issued	7	7
Additional paid-in capital	7,616	7,704
Treasury stock, at cost; 102,738,591 and 105,113,545 common shares	(6,312)	(6,462)
Retained earnings	14,173	13,388
Accumulated other comprehensive income	498	388
Total Valero Energy Corporation stockholders' equity	15,982	15,025
Noncontrolling interest	10	—
Total equity	15,992	15,025

Total liabilities and equity	$39,526	$37,621

See Condensed Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Millions of Dollars, Except Per Share Amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Operating revenues (a)	$31,293	$20,561	$57,601	$39,054
Costs and expenses:				
Cost of sales	28,380	18,227	52,948	35,283
Operating expenses:				
Refining	813	693	1,557	1,457
Retail	169	163	331	315
Ethanol	104	91	199	171
General and administrative expenses	151	131	281	228
Depreciation and amortization expense	386	350	751	690
Asset impairment loss	—	2	—	2
Total costs and expenses	30,003	19,657	56,067	38,146
Operating income	1,290	904	1,534	908
Other income, net	10	1	27	12
Interest and debt expense, net of capitalized interest	(107)	(117)	(224)	(244)
Income from continuing operations before income tax expense	1,193	788	1,337	676
Income tax expense	449	268	489	236
Income from continuing operations	744	520	848	440
Income (loss) from discontinued operations, net of income taxes	(1)	63	(7)	30
Net income	743	583	841	470
Less: Net loss attributable to noncontrolling interest	(1)	—	(1)	—
Net income attributable to Valero Energy Corporation stockholders	$744	$583	$842	$470
Net income attributable to Valero Energy Corporation stockholders:				
Continuing operations	$745	$520	$849	$440
Discontinued operations	(1)	63	(7)	30
Total	$744	$583	$842	$470
Earnings per common share:				
Continuing operations	$1.31	$0.92	$1.49	$0.78
Discontinued operations	—	0.11	(0.01)	0.05
Total	$1.31	$1.03	$1.48	$0.83
Weighted-average common shares outstanding (in millions)	567	563	567	563
Earnings per common share – assuming dilution:				
Continuing operations	$1.30	$0.92	$1.48	$0.78
Discontinued operations	—	0.11	(0.01)	0.05
Total	$1.30	$1.03	$1.47	$0.83
Weighted-average common shares outstanding – assuming dilution (in millions)	574	567	573	567
Dividends per common share	$0.05	$0.05	$0.10	$0.10
Supplemental information:				
(a) Includes excise taxes on sales by our U.S. retail system	$227	$225	$441	$433

See Condensed Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions of Dollars)
(Unaudited)

	Six Months Ended June 30, 2011	2010
Cash flows from operating activities:		
Net income	$841	$470
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	751	724
Noncash interest expense and other income, net	21	4
Asset impairment loss	—	2
Gain on sale of Delaware City Refinery assets	—	(92)
Stock-based compensation expense	23	22
Deferred income tax expense	166	83
Changes in current assets and current liabilities	1,147	613
Changes in deferred charges and credits and other operating activities, net	5	(56)
Net cash provided by operating activities	2,954	1,770
Cash flows from investing activities:		
Capital expenditures	(969)	(785)
Deferred turnaround and catalyst costs	(432)	(343)
Acquisition of pipeline and terminal facilities	(37)	—
Advance payment related to the Pembroke Acquisition	(37)	—
Acquisitions of ethanol plants	—	(260)
Proceeds from sale of the Delaware City Refinery assets and associated terminal and pipeline assets	—	220
Other investing activities, net	(19)	11
Net cash used in investing activities	(1,494)	(1,157)
Cash flows from financing activities:		
Non-bank debt:		
Borrowings	—	1,244
Repayments	(718)	(517)
Accounts receivable sales program:		
Proceeds from the sale of receivables	—	1,225
Repayments	—	(1,325)
Issuance of common stock in connection with stock-based compensation plans	30	11
Common stock dividends	(57)	(57)
Debt issuance costs	—	(10)
Contributions from noncontrolling interest	9	—
Other financing activities, net	7	4
Net cash provided by (used in) financing activities	(729)	575
Effect of foreign exchange rate changes on cash	42	(12)
Net increase in cash and temporary cash investments	773	1,176
Cash and temporary cash investments at beginning of period	3,334	825
Cash and temporary cash investments at end of period	$4,107	$2,001

See Condensed Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Millions of Dollars)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net income	$743	$583	$841	$470
Other comprehensive income (loss):				
Foreign currency translation adjustment	20	(138)	112	(37)
Pension and other postretirement benefits:				
Net loss arising during the period, net of income tax benefit of $-, $-, $-, and $-	—	(21)	—	(21)
Net gain reclassified into income, net of income tax expense of $-, $-, $1, and $-	(1)	(1)	(2)	(2)
Net loss on pension and other postretirement benefits	(1)	(22)	(2)	(23)
Derivative instruments designated and qualifying as cash flow hedges:				
Net loss arising during the period, net of income tax benefit of $-, $-, $-, and $1	—	—	—	(1)
Net gain reclassified into income, net of income tax expense of $-, $17, $-, and $34	—	(32)	—	(64)
Net loss on cash flow hedges	—	(32)	—	(65)
Other comprehensive income (loss)	19	(192)	110	(125)
Comprehensive income	762	391	951	345
Less: Comprehensive loss attributable to noncontrolling interest	(1)	—	(1)	—
Comprehensive income attributable to Valero Energy Corporation stockholders	$763	$391	$952	$345

See Condensed Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

General

As used in this report, the terms “Valero,” “we,” “us,” or “our” may refer to Valero Energy Corporation, one or more of its consolidated subsidiaries, or all of them taken as a whole.

These unaudited consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (GAAP) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities Exchange Act of 1934. Accordingly, they do not include all of the information and notes required by GAAP for complete consolidated financial statements. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. All such adjustments are of a normal recurring nature unless disclosed otherwise. Financial information for the three and six months ended June 30, 2011 and 2010 included in these Condensed Notes to Consolidated Financial Statements is derived from our unaudited consolidated financial statements. Operating results for the three and six months ended June 30, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011.

The consolidated balance sheet as of December 31, 2010 has been derived from our audited financial statements as of that date. For further information, refer to our consolidated financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2010.

We have evaluated subsequent events that occurred after June 30, 2011 through the filing of this Form 10 Q. Any material subsequent events that occurred during this time have been properly recognized or disclosed in these financial statements.

Consolidation of Joint Venture

On January 21, 2011, we entered into a joint venture agreement with Darling Green Energy LLC, a subsidiary of Darling International, Inc. (collectively, Darling), to form Diamond Green Diesel Holdings LLC (DGD Holdings). DGD Holdings, through its wholly owned subsidiary, Diamond Green Diesel LLC (DGD), will construct and operate a biomass-based diesel plant having a design feed capacity of 10,000 barrels per day that will process animal fats, used cooking oils, and other vegetable oils into renewable green diesel. The plant will be located next to our St. Charles Refinery. The aggregate cost of this facility is estimated to be approximately $368 million and the construction is expected to be completed in late 2012 or early 2013.

The joint venture agreement requires that contributions be made to DGD Holdings based on the percentage of units held by each member, which is currently on a 50/50 basis. In addition, on May 31, 2011, we agreed to lend DGD up to $221 million in order to finance 60 percent of the construction costs of the plant. Because of our controlling financial interest in DGD Holdings, we have consolidated the consolidated financial statements of DGD Holdings in these financial statements and have separately disclosed Darling’s noncontrolling interest.

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

Significant Accounting Policies
Reclassifications
In December 2010, we sold our Paulsboro Refinery to PBF Holding Company LLC. The results of operations of the Paulsboro Refinery for the three and six months ended June 30, 2010, therefore, have been presented as discontinued operations in the consolidated statements of income and are shown below (in millions):

	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Operating revenues	$1,214	$2,364
Income (loss) before income taxes	18	(18)

In addition, credit card fees previously recognized in 2010 in retail operating expenses have been reclassified to cost of sales as such fees are directly and jointly related to the sale transaction. This reclassification resulted in an increase in cost of sales and a decrease in retail operating expenses of $24 million and $45 million for the three and six months ended June 30, 2010, respectively.

Use of Estimates
The preparation of financial statements in conformity with GAAP 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. On an ongoing basis, we review our estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

New Accounting Pronouncements
In June 2011, the provisions of Accounting Standards Codification (ASC) Topic 220, “Comprehensive Income,” were amended to allow an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. In both choices, the entity is required to present reclassification adjustments on the face of the financial statements for items that are reclassified from other comprehensive income to net income in the statement where those components are presented. These provisions are effective for the first interim or annual period beginning after December 15, 2011, and are to be applied retrospectively, with early adoption permitted. The adoption of this guidance effective January 1, 2012 will not affect our financial position or results of operations because these requirements only affect disclosures.

In May 2011, the provisions of ASC Topic 820, “Fair Value Measurement,” were amended to clarify the application of existing fair value measurement requirements and to change certain fair value measurement and disclosure requirements. Amendments that change measurement and disclosure requirements relate to (i) fair value measurement of financial instruments that are managed within a portfolio, (ii) application of premiums and discounts in a fair value measurement, and (iii) additional disclosures about fair value measurements categorized within Level 3 of the fair value hierarchy. These provisions are effective for the first interim or annual period beginning after December 15, 2011. The adoption of this guidance effective January 1, 2012 will not affect our financial position or results of operations, but may result in additional disclosures.

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

In January 2011, the provisions of ASC Topic 310, “Receivables,” were amended to delay temporarily the effective date of disclosures relating to troubled debt restructurings, which were previously amended in July 2010, in order to allow the Financial Accounting Standards Board time to complete its deliberations on what constitutes a troubled debt restructuring. In April 2011, the provisions of ASC Topic 310 were amended to clarify the guidance on a creditor’s evaluations of whether it has granted a concession to the debtor and whether the debtor is experiencing financial difficulties. These provisions are effective for the first interim or annual period beginning on or after June 15, 2011. The new guidance should be applied retrospectively to restructurings occurring on or after the beginning of the annual period of adoption, with early adoption permitted. The adoption of this guidance effective July 1, 2011 did not affect our financial position or results of operations.

2. ACQUISITIONS AND DISPOSITION

Pembroke Acquisition
On August 1, 2011, we acquired 100 percent of the outstanding shares of Chevron Limited from a subsidiary of Chevron Corporation (Chevron). Chevron Limited owns and operates the Pembroke Refinery, which has a total throughput capacity of approximately 270,000 barrels per day and is located in Wales, United Kingdom. Chevron Limited also owns, directly and through various subsidiaries, an extensive network of marketing and logistics assets throughout the United Kingdom and Ireland. On the closing date, we paid $1.8 billion from available cash, of which $1.1 billion was for working capital based on estimated amounts at closing that are subject to adjustment. This acquisition is referred to as the Pembroke Acquisition.

The Pembroke Acquisition is consistent with our general business strategy and broadens the geographic diversity of our refining and marketing network.

A determination of the acquisition-date fair values of the assets acquired and the liabilities assumed in the Pembroke Acquisition is pending the completion of an independent appraisal and other evaluations. Disclosure of pro forma information for the Pembroke Acquisition for the three and six months ended June 30, 2011 and 2010 is impracticable as historical financial information is not readily available at this time.

Acquisition of Pipeline and Terminal Facilities
In June 2011, we acquired two product terminal facilities in Louisville and Lexington, Kentucky and a minority interest in the LouLex Pipeline system, which connects the terminal facilities, from a subsidiary of Chevron for cash consideration of $37 million. These assets provide storage and distribution facilities for our wholesale marketing business in eastern Kentucky, which is supplied primarily by our Memphis Refinery.

Because this acquisition was not material to our results of operations, we have not presented actual results of operations for this acquisition from the acquisition date through June 30, 2011 or pro forma results of operations for the three and six months ended June 30, 2011 and 2010. The consolidated statements of income for the three and six months ended June 30, 2011 include the results of this acquisition from its acquisition date.

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

Disposition of Delaware City Refinery Assets and Associated Terminal and Pipeline Assets
In June 2010, we sold our shutdown Delaware City Refinery assets and associated terminal and pipeline assets to wholly owned subsidiaries of PBF Energy Partners LP (PBF) for $220 million of cash proceeds. The sale resulted in a gain of $92 million ($58 million after taxes) related to the shutdown refinery assets and a gain of $3 million related to the terminal and pipeline assets. The gain on the sale of the shutdown refinery assets resulted from the proceeds we received for the scrap value of the assets and the reversal of certain liabilities recorded in the fourth quarter of 2009 associated with the shutdown of the refinery, which we did not incur because of the sale, and it is presented in discontinued operations for the three and six months ended June 30, 2010.

Results of operations for the Delaware City Refinery prior to its sale, excluding the gain on the sale, are shown below (in millions):

	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Operating revenues	$—	$—
Loss before income taxes	(7)	(33)

Acquisitions of Ethanol Plants
In December 2009, we signed an agreement with ASA Ethanol Holdings, LLC to buy two ethanol plants located in Linden, Indiana and Bloomingburg, Ohio and made a $20 million advance payment towards the acquisition of these plants. In January 2010, we completed the acquisition of these plants, including certain inventories, for total consideration of $202 million.

Also in December 2009, we received approval from a bankruptcy court to acquire an ethanol plant located near Jefferson, Wisconsin from Renew Energy LLC and made a $1 million advance payment towards the acquisition of this plant. We completed the acquisition of this plant, including certain receivables and inventories, in February 2010 for total consideration of $79 million.

3. IMPAIRMENT ANALYSIS

In late 2008, the U.S. and worldwide economies experienced severe disruptions in their capital and commodities markets resulting in a significant slowdown that persisted throughout 2009. This slowdown negatively impacted refining industry fundamentals and the demand and price for our refined products. Because of this negative impact, we decided to shut down our Aruba Refinery temporarily in July 2009, and it remained shut until January 2011. We decided to restart our Aruba Refinery due to improvements in the U.S. and worldwide economies during 2010 and the resulting improvement in refining industry fundamentals, both of which continued to improve during the first six months of 2011. Despite these improvements and the restart of the refinery, we analyzed our Aruba Refinery for potential impairment as of June 30, 2011 because of its recent temporary shutdown, its negative operating cash flows subsequent to its restart, and the sensitivity of its profitability to sour crude oil differentials. The price of sour crude oil is generally less than the price of sweet crude oil, and that price difference is referred to as the sour crude oil differential. Sour crude oil differentials have improved along with other refining industry fundamentals. We considered these positive developments in our impairment analysis and concluded that our Aruba Refinery was not

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

impaired as of June 30, 2011. Our cash flow estimates for the refinery are based on our expectation that sour crude oil differentials will continue to improve in connection with an increase in the demand for refined products and the increased production of sour crude oils. Should differentials fail to widen or fail to widen to amounts experienced in prior years, our cash flow estimates may be negatively impacted and we could ultimately determine that the refinery is impaired. The Aruba Refinery had a net book value of $953 million as of June 30, 2011; therefore, an impairment loss could be material to our results of operations.

In July 2011, we renewed our exploration of strategic alternatives related to our Aruba Refinery. We are continuing to pursue potential transactions for this refinery, which may include the sale of the refinery.

4. INVENTORIES

Inventories consisted of the following (in millions):

	June 30, 2011	December 31, 2010
Refinery feedstocks	$2,188	$2,225
Refined products and blendstocks	1,314	2,233
Ethanol feedstocks and products	182	201
Convenience store merchandise	109	101
Materials and supplies	195	187
Inventories	$3,988	$4,947

As of June 30, 2011 and December 31, 2010, the replacement cost (market value) of LIFO inventories exceeded their LIFO carrying amounts by approximately $7.9 billion and $6.1 billion, respectively.

5. DEBT

Non-Bank Debt

During the six months ended June 30, 2011, the following activity occurred related to our non-bank debt:

- in May 2011, we made a scheduled debt repayment of $200 million related to our 6.125% senior notes;
- in April 2011, we made scheduled debt repayments of $8 million related to our Series A 5.45%, Series B 5.40%, and Series C 5.40% industrial revenue bonds;
- in February 2011, we made a scheduled debt repayment of $210 million related to our 6.75% senior notes; and
- also in February 2011, we paid $300 million to acquire the Gulf Opportunity Zone Revenue Bonds Series 2010 (GO Zone Bonds), which were subject to mandatory tender. We expect to hold the GO Zone Bonds for our own account until conditions permit the remarketing of these bonds at an interest rate acceptable to us.

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

During the six months ended June 30, 2010, the following activity occurred related to our non-bank debt:

- in June 2010, we made a scheduled debt repayment of $25 million related to our 7.25% debentures;
- in May 2010, we redeemed our 6.75% senior notes with a maturity date of May 1, 2014 for $190 million, or 102.25% of stated value;
- in April 2010, we made scheduled debt repayments of $8 million related to our Series A 5.45%, Series B 5.40%, and Series C 5.40% industrial revenue bonds;
- in March 2010, we redeemed our 7.50% senior notes with a maturity date of June 15, 2015 for $294 million, or 102.5% of stated value; and
- in February 2010, we issued $400 million of 4.50% notes due in February 2015 and $850 million of 6.125% notes due in February 2020 for total net proceeds of $1.244 billion.

Bank Credit Facilities

We have a $2.4 billion revolving credit facility (the Revolver) that has a maturity date of November 2012. The Revolver has certain restrictive covenants, including a maximum debt-to-capitalization ratio of 60 percent. As of June 30, 2011 and December 31, 2010, our debt-to-capitalization ratio, calculated in accordance with the terms of the Revolver, was 18 percent and 25 percent, respectively. We believe that we will remain in compliance with this covenant.

In addition to the Revolver, one of our Canadian subsidiaries has a committed revolving credit facility under which it may borrow and obtain letters of credit up to C$115 million.

During the six months ended June 30, 2011 and 2010, we had no borrowings or repayments under our Revolver or the Canadian revolving credit facility. As of June 30, 2011 and December 31, 2010, we had no borrowings outstanding under the Revolver or the Canadian revolving credit facility.

We had outstanding letters of credit under our committed lines of credit as follows (in millions):

	Borrowing Capacity	Expiration	June 30, 2011	December 31, 2010
Letter of credit facility	$200	June 2012	$200	$—
Letter of credit facility	$300	June 2012	$230	$100
Revolver	$2,400	November 2012	$123	$399
Canadian revolving credit facility	C$115	December 2012	C$20	C$20

As of June 30, 2011 and December 31, 2010, we had $223 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 2011 to extend the maturity date to June 2012. As of June 30, 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 six months ended June 30, 2011. During the six months ended June 30, 2010, we sold $1.2 billion of eligible receivables and repaid $1.3 billion to the third-party entities and financial institutions. Proceeds from the sale of receivables under this facility are reflected as debt.

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

Capitalized Interest

Capitalized interest was $33 million and $22 million for the three months ended June 30, 2011 and 2010, respectively, and $60 million and $42 million for the six months ended June 30, 2011 and 2010, respectively.

6. COMMITMENTS AND CONTINGENCIES

Environmental Matters

The regulation of greenhouse gases at the federal level has now shifted from the U.S. Congress 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 and foreign governments have pursued independent regulation of greenhouse gases. 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. The 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 (although the CARB has proposed to delay the implementation until 2013). 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 increase significantly 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, which we intend to contest. We have not recorded a loss contingency liability with respect to this matter. While we believe that it is reasonably possible that we may suffer a loss with respect to one or more of the lawsuits, we do not believe that such an outcome in any one or more of these lawsuits would have a material adverse effect on our financial position or results of operations.

Other Litigation

We are also a party to additional claims and legal proceedings arising in the ordinary course of business. We have not recorded a loss contingency liability with respect to some of these matters because we have determined that it is remote that a loss has been incurred. For other matters, we have recorded a loss contingency liability where we have determined that it is probable that a loss has been incurred and that the loss is reasonably estimable. These loss contingency liabilities are not material to our financial position. We re-evaluate and update our loss contingency liabilities as matters progress over time, and we believe that any changes to the recorded liabilities will not be material to our financial position or results of operations.

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7. EQUITY

On July 28, 2011, our board of directors declared a regular quarterly cash dividend of $0.05 per common share payable on September 14, 2011 to holders of record at the close of business on August 17, 2011.

The following is a reconciliation of the beginning and ending balances (in millions) of equity attributable to our stockholders, equity attributable to the noncontrolling interest, and total equity for the six months ended June 30, 2011 and 2010:

	2011 Valero Stockholders' Equity	Non-controlling Interest	Total Equity	2010 Valero Stockholders' Equity	Non-controlling Interest	Total Equity
Balance at beginning of period	$15,025	$—	$15,025	$14,725	$—	$14,725
Net income (loss)	842	(1)	841	470	—	470
Dividends	(57)	—	(57)	(57)	—	(57)
Stock-based compensation expense	23	—	23	22	—	22
Tax deduction in excess of stock-based compensation expense	11	—	11	7	—	7
Transactions in connection with stock-based compensation plans:						
Stock issuances	30	—	30	11	—	11
Stock repurchases	(2)	—	(2)	(2)	—	(2)
Contributions from noncontrolling interest	—	11	11	—	—	—
Other comprehensive income (loss)	110	—	110	(125)	—	(125)
Balance at end of period	$15,982	$10	$15,992	$15,051	$—	$15,051

The noncontrolling interest relates to the DGD Holdings joint venture as discussed in Note 1.

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8. EMPLOYEE BENEFIT PLANS

The components of net periodic benefit cost related to our defined benefit plans were as follows for the three and six months ended June 30, 2011 and 2010 (in millions):

	Pension Plans		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Three months ended June 30:				
Service cost	$22	$21	$2	$2
Interest cost	22	21	5	7
Expected return on plan assets	(28)	(28)	—	—
Amortization of:				
Prior service cost (credit)	—	—	(5)	(5)
Net loss	3	1	1	1
Net periodic benefit cost	$19	$15	$3	$5
Six months ended June 30:				
Service cost	$45	$43	$5	$5
Interest cost	43	41	11	13
Expected return on plan assets	(56)	(56)	—	—
Amortization of:				
Prior service cost (credit)	1	1	(11)	(10)
Net loss	6	1	1	2
Net periodic benefit cost	$39	$30	$6	$10

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 significant contributions made to our pension plans during the six months ended June 30, 2011. We contributed $25 million to our pension plans in July 2011, and we expect to contribute an additional $75 million later in the third quarter of 2011. During the six months ended June 30, 2010, we contributed $53 million to our pension plans.

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9. EARNINGS PER COMMON SHARE

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

	Three Months Ended June 30,			
	2011		2010	
	Restricted Stock	Common Stock	Restricted Stock	Common Stock
Earnings per common share from continuing operations:				
Net income attributable to Valero stockholders from continuing operations		$745		$520
Less dividends paid:				
Common stock		29		29
Nonvested restricted stock		—		—
Undistributed earnings		$716		$491
Weighted-average common shares outstanding	3	567	3	563
Earnings per common share from continuing operations:				
Distributed earnings	$0.05	$0.05	$0.05	$0.05
Undistributed earnings	1.26	1.26	0.87	0.87
Total earnings per common share from continuing operations	$1.31	$1.31	$0.92	$0.92
Earnings per common share from continuing operations – assuming dilution:				
Net income attributable to Valero stockholders from continuing operations		$745		$520
Weighted-average common shares outstanding		567		563
Common equivalent shares:				
Stock options		5		3
Performance awards and unvested restricted stock		2		1
Weighted-average common shares outstanding – assuming dilution		574		567
Earnings per common share from continuing operations – assuming dilution		$1.30		$0.92

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	Six Months Ended June 30,			
	2011		2010	
	Restricted Stock	Common Stock	Restricted Stock	Common Stock
Earnings per common share from continuing operations:				
Net income attributable to Valero stockholders from continuing operations		$849		$440
Less dividends paid:				
Common stock		57		57
Nonvested restricted stock		—		—
Undistributed earnings		$792		$383
Weighted-average common shares outstanding	3	567	3	563
Earnings per common share from continuing operations:				
Distributed earnings	$0.10	$0.10	$0.10	$0.10
Undistributed earnings	1.39	1.39	0.68	0.68
Total earnings per common share from continuing operations	$1.49	$1.49	$0.78	$0.78
Earnings per common share from continuing operations – assuming dilution:				
Net income attributable to Valero stockholders from continuing operations		$849		$440
Weighted-average common shares outstanding		567		563
Common equivalent shares:				
Stock options		5		3
Performance awards and unvested restricted stock		1		1
Weighted-average common shares outstanding – assuming dilution		573		567
Earnings per common share from continuing operations – assuming dilution		$1.48		$0.78

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The following table reflects potentially dilutive securities (in millions) that were excluded from the calculation of "earnings 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 stock options for which the exercise prices were greater than the average market price of our common stock during each respective reporting period.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Stock options	6	11	6	11

10. SEGMENT INFORMATION

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

	Refining	Retail	Ethanol	Corporate	Total
Three months ended June 30, 2011:					
Operating revenues from external customers	$26,921	$3,128	$1,244	$—	$31,293
Intersegment revenues	2,311	—	52	—	2,363
Operating income (loss)	1,253	135	64	(162)	1,290
Three months ended June 30, 2010:					
Operating revenues from external customers	17,546	2,357	658	—	20,561
Intersegment revenues	1,591	—	56	—	1,647
Operating income (loss)	904	109	35	(144)	904
Six months ended June 30, 2011:					
Operating revenues from external customers	49,483	5,812	2,306	—	57,601
Intersegment revenues	4,308	—	100	—	4,408
Operating income (loss)	1,529	201	108	(304)	1,534
Six months ended June 30, 2010:					
Operating revenues from external customers	33,293	4,533	1,228	—	39,054
Intersegment revenues	3,099	—	111	—	3,210
Operating income (loss)	889	180	92	(253)	908

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

	June 30, 2011	December 31, 2010
Refining	$31,798	$30,363
Retail	1,999	1,925
Ethanol	927	953
Corporate	4,802	4,380
Total consolidated assets	$39,526	$37,621

11. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Six Months Ended June 30,	
	2011	2010
Decrease (increase) in current assets:		
Receivables, net	$(1,422)	$(394)
Inventories	978	102
Income taxes receivable	175	808
Prepaid expenses and other	(3)	124
Increase (decrease) in current liabilities:		
Accounts payable	1,147	122
Accrued expenses	202	(145)
Taxes other than income taxes	(52)	(151)
Income taxes payable	122	147
Changes in current assets and current liabilities	$1,147	$613

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

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- 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.

During the six months ended June 30, 2011, we received a noncash contribution of $2 million from the noncontrolling interest for property, plant and equipment related to DGD Holdings. There were no significant noncash investing or financing activities for the six months ended June 30, 2010.

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

	Six Months Ended June 30,	
	2011	2010
Interest paid in excess of amount capitalized	$221	$225
Income taxes paid, net	(10)	(797)

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 six months ended June 30, 2010 and are summarized as follows (in millions):

Cash provided by (used in) operating activities:	
Paulsboro Refinery	$32
Delaware City Refinery	(76)
Cash used in investing activities:	
Paulsboro Refinery	(28)
Delaware City Refinery	—

12. FAIR VALUE MEASUREMENTS

General

GAAP requires that certain financial instruments, such as derivative instruments, be recognized at their fair values in our consolidated balance sheets. However, other financial instruments, such as debt obligations, are not required to be recognized at their fair values, but GAAP provides an option to elect fair value accounting for these instruments. GAAP requires the disclosure of the fair values of all financial instruments, regardless of whether they are recognized at their fair values or carrying amounts in our consolidated balance sheets. For financial instruments recognized at fair value, GAAP requires the disclosure of their fair values by type of instrument, along with other information, including changes in the fair values of certain financial instruments recognized in income or other comprehensive income, and this information is provided below under “Recurring Fair Value Measurements.” For financial instruments not recognized at fair value, the disclosure of their fair values is provided below under “Other Financial Instruments.”

Nonfinancial assets, such as property, plant and equipment, and nonfinancial liabilities are recognized at their carrying amounts in our consolidated balance sheets. GAAP does not permit nonfinancial assets and liabilities to be remeasured at their fair values. However, GAAP requires the remeasurement of such assets

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and liabilities to their fair values upon the occurrence of certain events, such as the impairment of property, plant and equipment. In addition, if such an event occurs, GAAP requires the disclosure of the fair value of the asset or liability along with other information, including the gain or loss recognized in income in the period the remeasurement occurred. This information is provided below under “Nonrecurring Fair Value Measurements.”

GAAP provides a framework for measuring fair value and establishes a three-level fair value hierarchy that prioritizes inputs to valuation techniques based on the degree to which objective prices in external active markets are available to measure fair value. Following is a description of each of the levels of the fair value hierarchy.

- Level 1 - Observable inputs, such as unadjusted quoted prices in active markets for identical assets or liabilities.
- Level 2 - Inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.
- Level 3 - Unobservable inputs for the asset or liability for which there is little, if any, market activity at the measurement date. Unobservable inputs reflect our own assumptions about what market participants would use to price the asset or liability. The inputs are developed based on the best information available in the circumstances, which might include occasional market quotes or sales of similar instruments or our own financial data such as internally developed pricing models, discounted cash flow methodologies, as well as instruments for which the fair value determination requires significant judgment.

The financial instruments and nonfinancial assets and liabilities included in our disclosure of recurring and nonrecurring fair value measurements are categorized according to the fair value hierarchy based on the inputs used to measure their fair values.

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Recurring Fair Value Measurements
The tables below present information (in millions) about our financial instruments recognized at their fair values in our consolidated balance sheets categorized according to the fair value hierarchy of the inputs utilized by us to determine the fair values as of June 30, 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 June 30, 2011
Assets:					
Commodity derivative contracts	$5,018	$227	$—	$(4,815)	$430
Investments of nonqualified benefit plans	92	—	11	—	103
Other investments	—	—	—	—	—
Liabilities:					
Commodity derivative contracts	4,592	378	—	(4,815)	155
Firm commitments to purchase inventories	—	31	—	—	31
Nonqualified benefit plan obligations	39	—	—	—	39
RINs obligation	135	—	—	—	135

	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
Firm commitments to purchase inventories	—	17	—	—	17
Investments of nonqualified benefit plans	104	—	10	—	114
Other investments	—	—	—	—	—
Liabilities:					
Commodity derivative contracts	3,097	502	—	(3,560)	39
Nonqualified benefit plan obligations	36	—	—	—	36
RINs obligation	51	—	—	—	51

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CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A description of our financial instruments and the valuation methods used to measure those instruments at fair value are as follows:

- Commodity derivative contracts consist primarily of exchange-traded futures and swaps, and as disclosed in Note 13, some of these contracts are designated as hedging instruments. These contracts 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.
- Firm commitments to purchase inventories represent the fair value of firm commitments to purchase crude oil feedstocks and the fair value of fixed-price corn purchase contracts in connection with hedging activity as more fully described in Note 13. The fair values of these firm commitments and purchase contracts are measured using a market approach based on quoted prices from the commodity exchange, but because these commitments have contractual terms that are not identical to exchange-traded futures instruments with a comparable market price, they are categorized in Level 2 of the fair value hierarchy.
- Nonqualified benefit plan assets consist of investment securities held by our nonqualified defined benefit and nonqualified defined contribution plans. The nonqualified benefit plan obligations relate to our nonqualified defined contribution plans under which our obligations to eligible employees are equal to the fair value of the assets held by those plans. The nonqualified benefit plan assets 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.
- Other investments consist of (i) equity securities of private companies over which we do not exercise significant influence nor whose financial statements are consolidated into our financial statements and (ii) debt securities of a private company whose financial statements are not consolidated into our financial statements. These investments are categorized in Level 3 of the fair value hierarchy as the fair values of these investments are determined using the income approach based on internally developed analyses.
- Our RINs obligation represents a liability for the purchase of Renewable Identification Numbers (RINs) to satisfy our obligation to blend biofuels into the products we produce. A RIN represents a serial number assigned to each gallon of biofuel produced or imported into the U.S. as required by the EPA’s Renewable Fuel Standard, which was implemented in accordance with the Energy Policy Act of 2005. The EPA sets annual quotas for the percentage of biofuels that must be blended into motor fuels consumed in the U.S., and as a producer of motor fuels from petroleum, we are obligated to blend biofuels into the products we produce at a rate that is at least equal to the EPA’s quota. To the degree we are unable to blend at that rate, we must purchase RINs in the open market to satisfy our obligation. Our RINs obligation is based on our RINs deficiency and the price of those RINs as of the balance sheet date. Our RINs obligation is categorized in Level 1 of the fair value hierarchy and is measured at fair value using the market approach based on quoted prices from an independent pricing service.

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Cash collateral deposits of $376 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 June 30, 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 (Level 3).

	2011 Investments of Nonqualified Benefit Plans	Other Investments	2010 Investments of Nonqualified Benefit Plans	Other Investments
Three months ended June 30:				
Balance at beginning of period	$11	$—	$10	$—
Purchases	—	10	—	1
Total losses included in earnings	—	(10)	—	(1)
Transfers in and/or out of Level 3	—	—	—	—
Balance at end of period	$11	$—	$10	$—
The amount of total losses included in earnings attributable to the change in unrealized losses relating to assets still held at end of period	$—	$(10)	$—	$(1)
Six months ended June 30:				
Balance at beginning of period	$10	$—	$10	$—
Purchases	—	16	—	1
Total gains (losses) included in earnings	1	(16)	—	(1)
Transfers in and/or out of Level 3	—	—	—	—
Balance at end of period	$11	$—	$10	$—
The amount of total gains (losses) included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at end of period	$1	$(16)	$—	$(1)

Nonrecurring Fair Value Measurements
As of June 30, 2011 and December 31, 2010, there were no assets or liabilities that were measured and recorded at fair value on a nonrecurring basis.

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Other Financial Instruments

Financial instruments that we recognize in our consolidated balance sheets at their carrying amounts include cash and temporary cash investments, receivables, payables, debt and capital lease obligations. The fair values of these financial instruments approximate their carrying amounts, except for debt as shown in the table below (in millions):

	June 30, 2011	December 31, 2010
Carrying amount (excluding capital leases)	$7,588	$8,300
Fair value	8,835	9,492

The fair value of our debt is determined using the market approach based on quoted prices in active markets (Level 1).

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 (See Note 12).

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.

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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.

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 June 30, 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).

Derivative Instrument	Notional Contract Volumes by Year of Maturity 2011
Crude oil and refined products:	
Futures – long	5,878
Futures – short	18,734

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 June 30, 2011, we had no outstanding commodity derivative instruments that were designated as cash flow hedges.

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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 June 30, 2011, we had the following outstanding commodity derivative instruments that were entered into as economic hedges. 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	74,882	51,750
Swaps – short	73,791	51,750
Futures – long	203,662	10,584
Futures – short	198,509	9,326
Options – long	1,200	—
Options – short	1,200	—
Corn:		
Futures – long	78,065	8,405
Futures – short	109,420	19,155

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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 June 30, 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	12,167	1,500
Swaps – short	12,167	1,500
Futures – long	71,114	13,089
Futures – short	71,159	13,054
Options – long	1,545	—
Options – short	1,545	—
Natural gas:		
Futures – long	4,850	—
Futures – short	4,600	—
Corn:		
Futures – long	4,925	60
Futures – short	4,525	60

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.

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 June 30, 2011, we had commitments to purchase $480 million of U.S. dollars. These commitments matured on or before July 28, 2011.

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

Fair Values of Derivative Instruments
The following tables provide information about the fair values of our derivative instruments as of June 30, 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 June 30, 2011	
	Balance Sheet Location	Asset Derivatives	Liability Derivatives
Derivatives designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$939	$815
Total		$939	$815
Derivatives not designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$3,700	$3,777
Swaps	Prepaid expenses and other	39	35
Swaps	Accrued expenses	188	320
Options	Receivables, net	3	—
Options	Accrued expenses	—	23
Total		$3,930	$4,155
Total derivatives		$4,869	$4,970

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

	Balance Sheet Location	Fair Value as of December 31, 2010 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 June 30, 2011, we had net receivables related to derivative instruments of $1 million from counterparties in the refining industry and $3 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 June 30:							
Commodity contracts	Cost of sales	$140	$216	$(147)	$(207)	$(7)	$9
Six months ended June 30:							
Commodity contracts	Cost of sales	49	199	(61)	(191)	(12)	8

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 June 30:								
Commodity contracts	$—	$—	Cost of sales	$—	$49	Cost of sales	$—	$—
Six months ended June 30:								
Commodity contracts	—	(2)	Cost of sales	—	98	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 June 30, 2011. For the six months ended June 30, 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 June 30:			
Commodity contracts	Cost of sales	$(72)	$(76)
Foreign currency contracts	Cost of sales	5	16
Total		$(67)	$(60)
Six months ended June 30:			
Commodity contracts	Cost of sales	$(371)	$(115)
Foreign currency contracts	Cost of sales	(9)	3
Total		$(380)	$(112)

Included in the results above for the six months ended June 30, 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 June 30:			
Commodity contracts	Cost of sales	$8	$8
Six months ended June 30:			
Commodity contracts	Cost of sales	14	5

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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, Africa, 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 AB 32) 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.

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OVERVIEW AND OUTLOOK

For the second quarter of 2011, we reported net income attributable to Valero stockholders from continuing operations of $745 million, or $1.30 per share, compared to $520 million, or $0.92 per share, for the second quarter of 2010. For the first six months of 2011, we reported net income attributable to Valero stockholders from continuing operations of $849 million, or $1.48 per share, compared to $440 million, or $0.78 per share for the first six months of 2010. Included in the results for the first six months of 2011 was a $542 million loss ($352 million after taxes, or $0.61 per share) on commodity derivative contracts related to forward sales of refined products. These contracts were closed and realized in the first quarter of 2011. The improvement in net income attributable to Valero stockholders from continuing operations in the second quarter and first six months of 2011 versus the comparable periods of 2010 was primarily due to an increase in operating income attributable to the business segments outlined in the following tables (in millions):

	Three Months Ended June 30,		
	2011	2010	Change
Operating income (loss) by business segment:			
Refining	$1,253	$904	$349
Retail	135	109	26
Ethanol	64	35	29
Corporate	(162)	(144)	(18)
Total	$1,290	$904	$386

	Six Months Ended June 30,		
	2011	2010	Change
Operating income (loss) by business segment:			
Refining	$1,529	$889	$640
Retail	201	180	21
Ethanol	108	92	16
Corporate	(304)	(253)	(51)
Total	$1,534	$908	$626

Excluding the impact of the $542 million loss on commodity derivative contracts described above, total company operating income and our refining segment operating income would have been $2.1 billion for the first six months of 2011, which reflects a $1.2 billion improvement in operating results over the comparable 2010 period.

Refining segment operating income improved primarily due to increased margins for most of the products we produce. Our margin improvement included the benefits 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 favorable difference between the price of waterborne sweet crude oils, such as Louisiana Light Sweet (LLS) and Brent, and inland sweet crude oils, such as West Texas Intermediate (WTI). Many of our refineries process sour crude oils or WTI-type crude oils and these crude oils were priced significantly below waterborne sweet crude oils during the second quarter of 2011 and the first six months of 2011, versus the comparable 2010 periods.

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Our retail segment generated operating income of $135 million for the second quarter of 2011 compared to $109 million for the second quarter of 2010, and it generated $201 million of operating income for the first six months of 2011 compared to $180 million for the first six months of 2010. The increase in operating income in both the second quarter and first six months of 2011 was primarily due to higher retail fuel margins.

Our ethanol segment generated operating income of $64 million for the second quarter of 2011 compared to $35 million for the second quarter of 2010, and it generated $108 million of operating income for the first six months of 2011 compared to $92 million for the first six months of 2010. The increase in operating income in both the second quarter and first six months of 2011 was primarily due to improved operating margins combined with a full six months of operations related to 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 August 1, 2011, we acquired 100 percent of the outstanding shares of Chevron Limited from a subsidiary of Chevron Corporation. Chevron Limited owns and operates the Pembroke Refinery, which has a total throughput capacity of approximately 270,000 barrels per day and is located in Wales, United Kingdom. Chevron Limited also owns, directly and through various subsidiaries, an extensive network of marketing and logistics assets throughout the United Kingdom and Ireland. On the closing date, we paid $1.8 billion from available cash, of which $1.1 billion was for working capital based on estimated amounts at closing that are subject to adjustment. This acquisition is referred to as the Pembroke Acquisition.

As of the date of the filing of this report, the financial markets are experiencing significant volatility. The overall impact on our business is uncertain at this time 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 June 30,		
	2011	2010	Change
Operating revenues	$31,293	$20,561	$10,732
Costs and expenses:			
Cost of sales (d)	28,380	18,227	10,153
Operating expenses:			
Refining	813	693	120
Retail (d)	169	163	6
Ethanol	104	91	13
General and administrative expenses	151	131	20
Depreciation and amortization expense:			
Refining	339	301	38
Retail	27	27	—
Ethanol	9	9	—
Corporate	11	13	(2)
Asset impairment loss	—	2	(2)
Total costs and expenses	30,003	19,657	10,346
Operating income	1,290	904	386
Other income, net	10	1	9
Interest and debt expense, net of capitalized interest	(107)	(117)	10
Income from continuing operations before income tax expense	1,193	788	405
Income tax expense	449	268	181
Income from continuing operations	744	520	224
Income (loss) from discontinued operations, net of income taxes	(1)	63	(64)
Net income	743	583	160
Less: Net loss attributable to noncontrolling interest	(1)	—	(1)
Net income attributable to Valero stockholders	$744	$583	$161
Net income attributable to Valero stockholders:			
Continuing operations	$745	$520	$225
Discontinued operations	(1)	63	(64)
Total	$744	$583	$161
Earnings per common share – assuming dilution:			
Continuing operations	$1.30	$0.92	$0.38
Discontinued operations	—	0.11	(0.11)
Total	$1.30	$1.03	$0.27

See note references on page 43.

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

	Three Months Ended June 30,		
	2011	2010	Change
Refining (a) (b):			
Operating income	$1,253	$904	$349
Throughput margin per barrel (e)	$11.41	$9.57	$1.84
Operating costs per barrel:			
Operating expenses	3.86	3.49	0.37
Depreciation and amortization expense	1.61	1.52	0.09
Total operating costs per barrel	5.47	5.01	0.46
Operating income per barrel	$5.94	$4.56	$1.38
Throughput volumes (thousand barrels per day):			
Feedstocks:			
Heavy sour crude	450	472	(22)
Medium/light sour crude	418	409	9
Acidic sweet crude	128	58	70
Sweet crude	679	668	11
Residuals	293	211	82
Other feedstocks	105	116	(11)
Total feedstocks	2,073	1,934	139
Blendstocks and other	243	246	(3)
Total throughput volumes	2,316	2,180	136
Yields (thousand barrels per day):			
Gasolines and blendstocks	1,054	1,084	(30)
Distillates	786	720	66
Other products (f)	487	395	92
Total yields	2,327	2,199	128

See note references on page 43.

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

	Three Months Ended June 30,		
	2011	2010	Change
Gulf Coast:			
Operating income	$786	$650	$136
Throughput volumes (thousand barrels per day)	1,432	1,329	103
Throughput margin per barrel (e)	$11.30	$10.28	$1.02
Operating costs per barrel:			
Operating expenses	3.74	3.34	0.40
Depreciation and amortization expense	1.54	1.57	(0.03)
Total operating costs per barrel	5.28	4.91	0.37
Operating income per barrel	$6.02	$5.37	$0.65
Mid-Continent:			
Operating income	$393	$151	$242
Throughput volumes (thousand barrels per day)	398	390	8
Throughput margin per barrel (e)	$16.50	$9.13	$7.37
Operating costs per barrel:			
Operating expenses	4.01	3.54	0.47
Depreciation and amortization expense	1.65	1.36	0.29
Total operating costs per barrel	5.66	4.90	0.76
Operating income per barrel	$10.84	$4.23	$6.61
Northeast (a) (b):			
Operating income (loss)	$(17)	$7	$(24)
Throughput volumes (thousand barrels per day)	207	199	8
Throughput margin per barrel (e)	$3.36	$4.40	$(1.04)
Operating costs per barrel:			
Operating expenses	3.04	2.55	0.49
Depreciation and amortization expense	1.22	1.47	(0.25)
Total operating costs per barrel	4.26	4.02	0.24
Operating income (loss) per barrel	$(0.90)	$0.38	$(1.28)
West Coast:			
Operating income	$91	$98	$(7)
Throughput volumes (thousand barrels per day)	279	262	17
Throughput margin per barrel (e)	$10.65	$10.55	$0.10
Operating costs per barrel:			
Operating expenses	4.84	4.87	(0.03)
Depreciation and amortization expense	2.21	1.57	0.64
Total operating costs per barrel	7.05	6.44	0.61
Operating income per barrel	$3.60	$4.11	$(0.51)
Operating income for regions above	$1,253	$906	$347
Asset impairment loss applicable to refining	—	(2)	2
Total refining operating income	$1,253	$904	$349

See note references on page 43.

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

	Three Months Ended June 30,		
	2011	2010	Change
Feedstocks:			
Louisiana Light Sweet (LLS) crude oil	$117.96	$80.06	$37.90
LLS less West Texas Intermediate (WTI) crude oil	15.47	2.26	13.21
LLS less Alaska North Slope (ANS) crude oil	2.94	3.00	(0.06)
LLS less Brent crude oil	(0.64)	1.61	(2.25)
LLS less Mars crude oil	6.04	2.62	3.42
LLS less Maya crude oil	14.58	12.01	2.57
WTI crude oil	102.49	77.80	24.69
WTI less Mars crude oil	(9.43)	0.36	(9.79)
WTI less Maya crude oil	(0.89)	9.75	(10.64)
Products:			
U.S. Gulf Coast:			
Conventional 87 gasoline less LLS	$10.26	$7.97	$2.29
Ultra-low-sulfur diesel less LLS	11.49	9.88	1.61
Propylene less LLS	26.03	3.85	22.18
Conventional 87 gasoline less WTI	25.73	10.23	15.50
Ultra-low-sulfur diesel less WTI	26.96	12.14	14.82
Propylene less WTI	41.50	6.11	35.39
U.S. Mid-Continent:			
Conventional 87 gasoline less WTI	26.38	10.39	15.99
Ultra-low-sulfur diesel less WTI	28.83	13.29	15.54
U.S. Northeast:			
Conventional 87 gasoline less Brent	7.44	8.85	(1.41)
Ultra-low-sulfur diesel less Brent	12.53	12.93	(0.40)
Conventional 87 gasoline less WTI	23.55	9.50	14.05
Ultra-low-sulfur diesel less WTI	28.64	13.58	15.06
U.S. West Coast:			
CARBOB 87 gasoline less ANS	14.54	17.24	(2.70)
CARB diesel less ANS	19.21	15.19	4.02
CARBOB 87 gasoline less WTI	27.07	16.50	10.57
CARB diesel less WTI	31.74	14.45	17.29
New York Harbor corn crush (dollars per gallon)	0.07	0.36	(0.29)

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See note references on page 43.

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

	Three Months Ended June 30, 2011	2010	Change
Retail–U.S.: (d)			
Operating income	$87	$76	$11
Company-operated fuel sites (average)	995	990	5
Fuel volumes (gallons per day per site)	5,094	5,196	(102)
Fuel margin per gallon	$0.204	$0.186	$0.018
Merchandise sales	$323	$316	$7
Merchandise margin (percentage of sales)	28.4%	28.1%	0.3%
Margin on miscellaneous sales	$22	$22	$—
Operating expenses	$103	$104	$(1)
Depreciation and amortization expense	$18	$18	$—
Retail–Canada: (d)			
Operating income	$48	$33	$15
Fuel volumes (thousand gallons per day)	3,182	3,098	84
Fuel margin per gallon	$0.319	$0.260	$0.059
Merchandise sales	$68	$61	$7
Merchandise margin (percentage of sales)	29.8%	29.9%	(0.1)%
Margin on miscellaneous sales	$11	$9	$2
Operating expenses	$66	$59	$7
Depreciation and amortization expense	$9	$9	$—
Ethanol (c):			
Operating income	$64	$35	$29
Production (thousand gallons per day)	3,397	3,190	207
Gross margin per gallon of production (e)	$0.57	$0.47	$0.10
Operating costs per gallon of production:			
Operating expenses	0.33	0.31	0.02
Depreciation and amortization expense	0.03	0.03	—
Total operating costs per gallon of production	0.36	0.34	0.02
Operating income per gallon of production	$0.21	$0.13	$0.08

See note references on page 43.

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The following notes relate to references on pages 38 through 42.

(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 June 30, 2010. The refining segment and Northeast region operating highlights exclude the Paulsboro Refinery for the three months ended June 30, 2010.

(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 June 30, 2010. In addition, the refining segment and Northeast region operating highlights exclude the Delaware City Refinery for three months ended June 30, 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. 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 $24 million for the three months ended June 30, 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 June 30, 2010 have been restated to reflect this reclassification.

(e) Throughput margin per barrel represents operating revenues less cost of sales of our refining segment divided by throughput volumes. Gross margin per gallon of production represents operating revenues less cost of sales of our ethanol segment divided by production volumes.

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

(g) 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.

(h) Average market reference prices for 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 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 52 percent (or $10.7 billion) for the second quarter of 2011 compared to the second quarter of 2010 primarily as a result of higher refined product prices and higher throughput volumes between the two periods related to our refining segment operations. Operating income increased $386 million and income from continuing operations before taxes increased $405 million for the second quarter of 2011 compared to amounts reported for the second quarter of 2010 primarily due to a $349 million increase in refining segment operating income discussed below.

Refining

Refining segment operating income increased 39 percent (or $349 million) from $904 million for the second quarter of 2010 to $1.3 billion for the second quarter of 2011.

The $349 million improvement in operating results was primarily due to a 19 percent increase in throughput margin per barrel (a $1.84 per barrel increase between the comparable periods) combined with a 6 percent increase in total throughput volumes (a 136,000 barrel per day increase between the comparable periods). The increase in throughput margin per barrel was caused by an improvement in distillate and gasoline margins in our Gulf Coast and Mid-Continent refining regions. Our throughput margin per barrel also benefited from 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 $11.49 per barrel for the second quarter of 2011, compared to $9.88 per barrel for the second quarter of 2010, representing a favorable increase of $1.61 per barrel. Similar increases in distillate margins were experienced in other regions. We estimate that the increase in margin for distillates had a $223 million positive impact to our overall refining margin, quarter versus quarter, as we produced 786,000 barrels per day of distillates during the second quarter of 2011. Distillate margins were higher in the second quarter of 2011 as compared to the second quarter of 2010 due to an increase in the worldwide industrial demand for these products.

The LLS-based benchmark reference margin for U.S. Gulf Coast Conventional 87 gasoline (Conventional 87 gasoline) was $10.26 per barrel for the second quarter of 2011, compared to $7.97 per barrel for the second quarter of 2010, representing a favorable increase of $2.29 per barrel. A more significant increase in the gasoline margin was experienced in the U.S. Mid-Continent region as we process a higher proportion of WTI versus LLS-based feedstocks in this region. We estimate that the overall increase in gasoline margins had a $65 million positive impact to our overall refining margin, quarter versus quarter, as we produced 1,054,000 barrels per day of gasoline during the second quarter of 2011. Gasoline margins were higher in the U.S. Gulf Coast and U.S. Mid-Continent regions in the second quarter of 2011 as compared to the second quarter of 2010 due to the price of gasoline increasing at a higher rate than the cost of crude oil processed in those regions. Conversely, gasoline margins were lower in the U.S. Northeast and U.S. West Coast regions in the second quarter of 2011 as compared to the second quarter of 2010 due to the price of gasoline increasing at a lower rate than the cost of crude oil processed in those regions. 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 increased 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 significant 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 or 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 $14.58 per barrel to LLS crude oil, which is a type of sweet crude oil, during the second quarter of 2011. This compares to a discount of $12.01 per barrel during the second quarter of 2010, representing a favorable increase of $2.57 per barrel. We estimate that the wider discounts for all types of sour crude oil that we process had a $309 million positive impact to our overall refining margin, quarter versus quarter, as we processed 868,000 barrels per day of sour crude oils.

The improvements discussed above were partially offset by a 17 percent (or $120 million) increase in refining operating expenses for the second quarter of 2011 compared to the second quarter of 2010. This increase was primarily due to a $33 million increase in maintenance expenses, a $40 million increase in employee-related expenses, and a $22 million increase in chemicals and catalyst costs.

Retail

Retail segment operating income was $135 million for the second quarter of 2011 compared to $109 million for the second quarter of 2010. This 24 percent (or $26 million) increase was due to a $26 million improvement in fuel margin between the quarters, which resulted from high retail pump prices.

Ethanol

Ethanol segment operating income was $64 million for the second quarter of 2011 compared to $35 million for the second quarter of 2010. The $29 million increase in operating income was primarily due to a $40 million increase in gross margin, partially offset by a $13 million increase in operating expenses.

The increase in gross margin was due to an increase in ethanol production (a 207,000 gallon per day increase between the comparable periods), which resulted from higher utilization rates and increased yield from the

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corn feedstock that we processed during the second quarter of 2011, and a 21 percent increase in the gross margin per gallon of ethanol production (a $0.10 per gallon increase between the comparable periods).

The increase in operating expenses was primarily due to a $10 million increase in energy costs and chemical expenses.

Corporate Expenses and Other

General and administrative expenses increased $20 million from the second quarter of 2010 to the second quarter of 2011 primarily due to a $15 million increase in variable compensation expense and $4 million in costs incurred in connection with the Pembroke Acquisition.

“Other income, net” for the second quarter of 2011 increased $9 million from the second quarter of 2010 primarily due to an increase of $3 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, net of capitalized interest” for the second quarter of 2011 decreased $10 million from the second quarter of 2010. This decrease is primarily due to a $10 million increase in capitalized interest due to a corresponding increase in capital expenditures between the quarters and the resumption of construction activity on previously suspended projects.

Income tax expense increased $181 million from the second quarter of 2010 to the second quarter of 2011 mainly as a result of higher operating income in 2011 and the nonrecurrence of a $20 million income tax benefit recognized in 2010 related to a tax settlement with the Government of Aruba.

Income from discontinued operations of $63 million for the second quarter of 2010 is primarily due to a $58 million after-tax gain on the sale of the shutdown refinery assets at Delaware City, which resulted from the proceeds we received for the scrap value of the shutdown refinery assets and the reversal of certain liabilities recorded in the fourth quarter of 2009 associated with the shutdown of the refinery, which were not incurred because of the sale.

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

	Six Months Ended June 30,		
	2011	2010	Change
Operating revenues	$57,601	$39,054	$18,547
Costs and expenses:			
Cost of sales (d) (e)	52,948	35,283	17,665
Operating expenses:			
Refining	1,557	1,457	100
Retail (d)	331	315	16
Ethanol	199	171	28
General and administrative expenses	281	228	53
Depreciation and amortization expense:			
Refining	655	595	60
Retail	55	53	2
Ethanol	18	17	1
Corporate	23	25	(2)
Asset impairment loss	—	2	(2)
Total costs and expenses	56,067	38,146	17,921
Operating income	1,534	908	626
Other income, net	27	12	15
Interest and debt expense, net of capitalized interest	(224)	(244)	20
Income from continuing operations before income tax expense	1,337	676	661
Income tax expense	489	236	253
Income from continuing operations	848	440	408
Income (loss) from discontinued operations, net of income taxes	(7)	30	(37)
Net income	841	470	371
Less: Net loss attributable to noncontrolling interest	(1)	—	(1)
Net income attributable to Valero stockholders	$842	$470	$372
Net income attributable to Valero stockholders:			
Continuing operations	$849	$440	$409
Discontinued operations	(7)	30	(37)
Total	$842	$470	$372
Earnings per common share – assuming dilution:			
Continuing operations	$1.48	$0.78	$0.70
Discontinued operations	(0.01)	0.05	(0.06)
Total	$1.47	$0.83	$0.64

See note references on page 51.

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

	Six Months Ended June 30,		
	2011	2010	Change
Refining (a) (b):			
Operating income (e)	$1,529	$889	$640
Throughput margin per barrel (e) (f)	$9.35	$7.89	$1.46
Operating costs per barrel:			
Operating expenses	3.89	3.91	(0.02)
Depreciation and amortization expense	1.64	1.59	0.05
Total operating costs per barrel	5.53	5.50	0.03
Operating income per barrel	$3.82	$2.39	$1.43
Throughput volumes (thousand barrels per day):			
Feedstocks:			
Heavy sour crude	412	456	(44)
Medium/light sour crude	395	397	(2)
Acidic sweet crude	100	50	50
Sweet crude	672	628	44
Residuals	271	174	97
Other feedstocks	121	117	4
Total feedstocks	1,971	1,822	149
Blendstocks and other	241	238	3
Total throughput volumes	2,212	2,060	152
Yields (thousand barrels per day):			
Gasolines and blendstocks	1,005	1,025	(20)
Distillates	741	659	82
Other products (g)	476	397	79
Total yields	2,222	2,081	141

See note references on page 51.

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

	Six Months Ended June 30, 2011	2010	Change
Gulf Coast:			
Operating income (e)	$897	$639	$258
Throughput volumes (thousand barrels per day)	1,366	1,234	132
Throughput margin per barrel (e) (f)	$9.01	$8.35	$0.66
Operating costs per barrel:			
Operating expenses	3.80	3.85	(0.05)
Depreciation and amortization expense	1.58	1.64	(0.06)
Total operating costs per barrel	5.38	5.49	(0.11)
Operating income per barrel	$3.63	$2.86	$0.77
Mid-Continent:			
Operating income (e)	$560	$140	$420
Throughput volumes (thousand barrels per day)	401	377	24
Throughput margin per barrel (e) (f)	$13.09	$7.32	$5.77
Operating costs per barrel:			
Operating expenses	3.83	3.79	0.04
Depreciation and amortization expense	1.54	1.48	0.06
Total operating costs per barrel	5.37	5.27	0.10
Operating income per barrel	$7.72	$2.05	$5.67
Northeast (a) (b):			
Operating income	$39	$45	$(6)
Throughput volumes (thousand barrels per day)	208	187	21
Throughput margin per barrel (f)	$5.19	$5.99	$(0.80)
Operating costs per barrel:			
Operating expenses	2.93	3.10	(0.17)
Depreciation and amortization expense	1.20	1.56	(0.36)
Total operating costs per barrel	4.13	4.66	(0.53)
Operating income per barrel	$1.06	$1.33	$(0.27)
West Coast:			
Operating income (e)	$33	$67	$(34)
Throughput volumes (thousand barrels per day)	237	262	(25)
Throughput margin per barrel (e) (f)	$8.60	$7.89	$0.71
Operating costs per barrel:			
Operating expenses	5.37	4.92	0.45
Depreciation and amortization expense	2.46	1.55	0.91
Total operating costs per barrel	7.83	6.47	1.36
Operating income per barrel	$0.77	$1.42	$(0.65)
Operating income for regions above	$1,529	$891	$638
Asset impairment loss applicable to refining	—	(2)	2
Total refining operating income	$1,529	$889	$640

See note references on page 51.

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

	Six Months Ended June 30, 2011	2010	Change
Feedstocks:			
LLS crude oil	$111.49	$79.70	$31.79
LLS less WTI	13.27	1.46	11.81
LLS less ANS crude oil	3.36	1.90	1.46
LLS less Brent crude oil	(0.52)	2.34	(2.86)
LLS less Mars crude oil	4.81	3.12	1.69
LLS less Maya crude oil	15.13	10.79	4.34
WTI crude oil	98.22	78.24	19.98
WTI less Mars crude oil	(8.46)	1.66	(10.12)
WTI less Maya crude oil	1.86	9.33	(7.47)
Products:			
U.S. Gulf Coast:			
Conventional 87 gasoline less LLS	$7.04	$7.22	$(0.18)
Ultra-low-sulfur diesel less LLS	12.54	8.36	4.18
Propylene less LLS	22.76	10.40	12.36
Conventional 87 gasoline less WTI	20.31	8.68	11.63
Ultra-low-sulfur diesel less WTI	25.81	9.82	15.99
Propylene less WTI	36.03	11.86	24.17
U.S. Mid-Continent:			
Conventional 87 gasoline less WTI	21.14	8.55	12.59
Ultra-low-sulfur diesel less WTI	26.97	10.00	16.97
U.S. Northeast:			
Conventional 87 gasoline less Brent	5.69	9.57	(3.88)
Ultra-low-sulfur diesel less Brent	13.78	12.14	1.64
Conventional 87 gasoline less WTI	19.48	8.69	10.79
Ultra-low-sulfur diesel less WTI	27.57	11.26	16.31
U.S. West Coast:			
CARBOB 87 gasoline less ANS	14.95	13.97	0.98
CARB diesel less ANS	19.96	11.87	8.09
CARBOB 87 gasoline less WTI	24.86	13.53	11.33
CARB diesel less WTI	29.87	11.43	18.44
New York Harbor corn crush (dollars per gallon)	0.07	0.41	(0.34)

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See note references on page 51.

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

	Six Months Ended June 30, 2011	2010	Change
Retail–U.S.: (d)			
Operating income	$106	$109	$(3)
Company-operated fuel sites (average)	994	989	5
Fuel volumes (gallons per day per site)	4,995	5,070	(75)
Fuel margin per gallon	$0.142	$0.148	$(0.006)
Merchandise sales	$606	$588	$18
Merchandise margin (percentage of sales)	28.3%	28.1%	0.2%
Margin on miscellaneous sales	$44	$44	$—
Operating expenses	$201	$198	$3
Depreciation and amortization expense	$37	$36	$1
Retail–Canada: (d)			
Operating income	$95	$71	$24
Fuel volumes (thousand gallons per day)	3,208	3,088	120
Fuel margin per gallon	$0.318	$0.272	$0.046
Merchandise sales	$125	$113	$12
Merchandise margin (percentage of sales)	29.8%	30.3%	(0.5)%
Margin on miscellaneous sales	$22	$19	$3
Operating expenses	$130	$117	$13
Depreciation and amortization expense	$18	$17	$1
Ethanol (c):			
Operating income	$108	$92	$16
Production (thousand gallons per day)	3,340	2,864	476
Gross margin per gallon of production (f)	$0.54	$0.54	$—
Operating costs per gallon of production:			
Operating expenses	0.33	0.33	—
Depreciation and amortization expense	0.03	0.03	—
Total operating costs per gallon of production	0.36	0.36	—
Operating income per gallon of production	$0.18	$0.18	$—

See note references on page 51.

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The following notes relate to references on pages 46 through 50.

(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 six months ended June 30, 2010. The refining segment and Northeast region operating highlights exclude the Paulsboro Refinery for the six months ended June 30, 2010.

(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 six months ended June 30, 2010. In addition, the refining segment and Northeast region operating highlights exclude the Delaware City Refinery for the six months ended June 30, 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. 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 $45 million for the six months ended June 30, 2010 have been reclassified from retail operating expenses to cost of sales. The Retail–U.S. and Retail–Canada operating highlights for the six months ended June 30, 2010 have been restated to reflect this reclassification.

(e) Cost of sales for the six months ended June 30, 2011 includes a loss of $542 million ($352 million after taxes) on commodity derivative contracts related to forward sales of refined products. 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 $1.35 reduction in refining throughput margin per barrel for the six months ended June 30, 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 $1.51 per barrel; Mid-Continent- $122 million, or $1.68 per barrel; and West Coast- $48 million, or $1.11 per barrel.

(f) Throughput margin per barrel represents operating revenues less cost of sales of our refining segment divided by throughput volumes. Gross margin per gallon of production represents operating revenues less cost of sales of our ethanol segment divided by production 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 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 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 47 percent (or $18.5 billion) for the first six months of 2011 compared to the first six months of 2010 primarily as a result of higher refined product prices and higher throughput volumes between the two periods related to our refining segment operations. Operating income increased $626 million and income from continuing operations before taxes increased $661 million for the first six months of 2011 compared to amounts reported for the first six months of 2010 primarily due to a $640 million increase in refining segment operating income discussed below.

Refining

Refining segment operating income increased 72 percent (or $640 million) from $889 million for the first six months of 2010 to $1.5 billion for the first six months of 2011. The $640 million increase in refining segment operating income is due to an overall improvement in refining operating results of $1.2 billion, offset by a $542 million loss on commodity derivative contracts related to forward sales of refined products. These contracts were closed and realized in the first quarter of 2011.

The $1.2 billion improvement in operating results was primarily due to a 36 percent increase in throughput margin per barrel (a $2.81 per barrel increase between the comparable periods, consisting of the increase of $1.46 per barrel adjusted for the $1.35 per barrel impact of the $542 million loss discussed above) combined with a 7 percent increase in total throughput volumes (a 152,000 barrel per day increase between the comparable periods). The increase in throughput margin per barrel was caused by an improvement in LLS-based distillate margins and 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 $12.54 per barrel for the first six months of 2011, compared to $8.36 per barrel for the first six months of 2010, representing a favorable increase of $4.18 per barrel. Similar increases in distillate margins were experienced in other regions. We estimate that the increase in margin for distillates had a $714 million positive impact to our overall refining margin, six months versus six months, as we produced 741,000 barrels per day of distillates during the first six months of 2011. Distillate margins were higher in the first six months of 2011 as compared to the first six months of 2010 due to an increase in the worldwide industrial demand for these products.

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 $15.13 per barrel to LLS crude oil, which is a type of sweet crude oil, during the first six months of 2011. This compares to a discount of $10.79 per barrel during the first six months of 2010, representing a favorable increase of $4.34 per barrel. We estimate that the wider discounts for all types of sour crude oil that we process had a $790 million positive impact to our overall refining margin, six months versus six months, as we processed 807,000 barrels per day of sour crude oils during the first six months of 2011.

The improvements discussed above were partially offset by a 7 percent (or $100 million) increase in refining operating expenses for the first six months of 2011 compared to the first six months of 2010. This increase was primarily due to a $24 million increase in maintenance expenses, a $48 million increase in employee-related expenses, and a $37 million increase in chemicals and catalyst costs.

Retail

Retail segment operating income was $201 million for the first six months of 2011 compared to $180 million for the first six months of 2010. This 12 percent (or $21 million) increase was primarily due to improved retail fuel margins of $26 million and retail merchandise margins of $9 million, offset by higher operating expenses of $16 million, of which $9 million related to the strengthening of the Canadian dollar relative to the U.S. dollar in our Canadian operations.

Ethanol

Ethanol segment operating income was $108 million for the first six months of 2011 compared to $92 million for the first six months of 2010. The $16 million increase in operating income was primarily due to a $45 million increase in gross margin, partially offset by a $28 million increase in operating expenses.

Gross margin increased from the first six months of 2010 to the first six months of 2011 due an increase in ethanol production (a 476,000 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 and higher utilization rates during 2011.

The increase in operating expenses was primarily due to $23 million of additional expenses related to the operation of the three ethanol plants we acquired in the first quarter of 2010 for a full six months in 2011.

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Corporate Expenses and Other

General and administrative expenses increased $53 million from the first six months of 2010 to the first six months 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 period, and a $15 million increase in variable compensation expense.

“Other income, net” for the first six months of 2011 increased $15 million from the first six months of 2010 primarily due to an increase of $7 million in interest income earned on cash held in interest-bearing accounts and $6 million in interest on the note receivable related to the sale of our Paulsboro Refinery in December 2010.

“Interest and debt expense, net of capitalized interest” for the first six months of 2011 decreased $20 million from the first six months of 2010. This decrease is primarily due to an increase of $18 million in capitalized interest due to a corresponding increase in capital expenditures between the quarters and the resumption of construction activity on previously suspended projects.

Income tax expense increased $253 million from the first six months of 2010 to the first six months of 2011 mainly as a result of higher operating income in 2011 and the nonrecurrence of a $20 million income tax benefit recognized in 2010 related to a tax settlement with the Government of Aruba.

The loss from discontinued operations of $7 million for the first six months of 2011 primarily represents adjustments to the working capital settlement related to the sale of our Paulsboro Refinery in December 2010. The income from discontinued operations of $30 million for the first six months of 2010 represents a $58 million after-tax gain on the sale of the shutdown refinery assets at Delaware City, offset by a $28 million loss from the discontinued operations of the Delaware City and Paulsboro Refineries.

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LIQUIDITY AND CAPITAL RESOURCES

Cash Flows for the Six Months Ended June 30, 2011 and 2010

Net cash provided by operating activities for the first six months of 2011 was $3.0 billion compared to $1.8 billion for the first six months of 2010. The increase in cash generated from operating activities was primarily due to a $534 million favorable effect from changes in working capital between the periods, combined with the $626 million increase in operating income discussed above under “RESULTS OF OPERATIONS.” Changes in cash provided by or used for working capital during the first six 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 six months of 2011 was used mainly to:

- fund $1.4 billion of capital expenditures and deferred turnaround and catalyst costs;
- make scheduled long-term note repayments of $418 million and acquire the Gulf Opportunity Zone Revenue Bonds Series 2010 (GO Zone Bonds) for $300 million;
- pay common stock dividends of $57 million; and
- increase available cash on hand by $773 million.

The net cash generated from operating activities during the first six months of 2010, combined with $1.2 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, and $220 million of proceeds from the sale of the Delaware City Refinery assets and associated terminal and pipeline assets as discussed in Note 2 of Condensed Notes to Consolidated Financial Statements, were used mainly to:

- fund $1.1 billion of capital expenditures and deferred turnaround and catalyst costs;
- redeem our 7.50% senior notes for $294 million and our 6.75% senior notes for $190 million;
- make scheduled long-term note repayments of $33 million;
- make repayments under our accounts receivable sales facility of $100 million;
- purchase additional ethanol plants for $260 million;
- pay common stock dividends of $57 million; and
- increase available cash on hand by $1.2 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 six months ended June 30, 2010 and are summarized as follows (in millions):

Cash provided by (used in) operating activities:	
Paulsboro Refinery	$32
Delaware City Refinery	(76)
Cash used in investing activities:	
Paulsboro Refinery	(28)
Delaware City Refinery	—

Capital Investments

During the six months ended June 30, 2011, we expended $969 million for capital expenditures and $432 million for deferred turnaround and catalyst costs. Capital expenditures for the six months ended June 30, 2011 included $114 million of costs related to environmental projects.

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For 2011, we expect to incur approximately $3.2 billion for capital investments, including approximately $2.5 billion for capital expenditures (approximately $270 million of which is for environmental projects) and approximately $650 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.

Pembroke Acquisition

On August 1, 2011, we acquired 100 percent of the outstanding shares of Chevron Limited from a subsidiary of Chevron Corporation. Chevron Limited owns and operates the Pembroke Refinery, which has a total throughput capacity of approximately 270,000 barrels per day and is located in Wales, United Kingdom. Chevron Limited also owns, directly and through various subsidiaries, an extensive network of marketing and logistics assets throughout the United Kingdom and Ireland. On the closing date, we paid $1.8 billion from available cash, of which $1.1 billion was for working capital based on estimated amounts at closing that are subject to adjustment.

Contractual Obligations

As of June 30, 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. In April 2011, we made scheduled debt repayments of $8 million related to our Series A 5.45%, Series B 5.40%, and Series C 5.40% industrial revenue bonds. In May 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 2012. As of June 30, 2011, the amount of eligible receivables sold was $100 million.

During the six months ended June 30, 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 August 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)

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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.

Other Commercial Commitments

As of June 30, 2011, our committed lines of credit were as follows (in millions):

	Borrowing Capacity	Expiration	Outstanding Letters of Credit
Letter of credit facility	$200	June 2012	$200
Letter of credit facility	$300	June 2012	$230
Revolving credit facility	$2,400	November 2012	$123
Canadian revolving credit facility	C$115	December 2012	C$20

As of June 30, 2011, we had no amounts borrowed under our revolving credit facilities. The letters of credit outstanding as of June 30, 2011 expire during 2011 and 2012.

Stock Purchase Programs

As of June 30, 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 contributed $25 million to our pension plans in July 2011, and we expect to contribute an additional $75 million later in the third quarter of 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.

The regulation of greenhouse gases at the federal level has now shifted from the U.S. Congress 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

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position, results of operations, and liquidity.

In addition, certain states and foreign governments have pursued independent regulation of greenhouse gases. 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 (although the CARB has proposed to delay the implementation until 2013). 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 increase significantly 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.

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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.

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 consolidated balance sheets 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
June 30, 2011:		
Gain (loss) in fair value due to:		
10% increase in underlying commodity prices	$(37)	$—
10% decrease in underlying commodity prices	37	—
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 June 30, 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 June 30, 2011 or December 31, 2010.

	June 30, 2011 Expected Maturity Dates							
	2011	2012	2013	2014	2015	There-after	Total	Fair Value
Debt (excluding capital lease obligations):								
Fixed rate	$—	$759	$489	$209	$484	$5,605	$7,546	$8,735
Average interest rate	— %	6.9 %	5.5 %	4.8 %	5.2 %	7.2 %	6.9 %	
Floating rate	$—	$100	$—	$—	$—	$—	$100	$100
Average interest rate	— %	0.5 %	— %	— %	— %	— %	0.5 %	

	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 June 30, 2011, we had commitments to purchase $480 million of U.S. dollars. Our market risk was minimal on these contracts, as they matured on or before July 28, 2011, resulting in a $4 million loss in the third 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 June 30, 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.

Illinois Environmental Protection Agency (The Premcor Refining Group Inc. former Clark Retail Enterprises, Inc. retail sites). The Illinois Environmental Protection Agency (IEPA) demanded stipulated penalties relating to certain retail sites in Illinois that were formerly owned by Premcor. In 2006, we entered into a consent order for the cleanup of several retail sites. At issue was our alleged failure to timely reach “no further action” status on a prescribed number of the sites. We recently agreed to a settlement in principle with the IEPA to resolve this matter.

Texas Commission on Environmental Quality (TCEQ) (Corpus Christi West Refinery and Texas City Refinery). In our annual report on Form 10-K for the year ended December 31, 2010, we disclosed outstanding environmental proceedings with the TCEQ relating to alleged excess air emissions at cooling towers in our Corpus Christi West Refinery and alleged flaring emissions at our Texas City Refinery. We recently entered into settlement agreements with the TCEQ regarding these and certain other immaterial proceedings, thus resolving this disclosed matter.

Texas Commission on Environmental Quality (TCEQ) (McKee Refinery). Our McKee Refinery received a proposed agreed order from the TCEQ with a proposed penalty of $116,169 for a notice of enforcement (NOE) issued in April 2011. The NOE is for alleged violations noted during an annual air compliance inspection conducted earlier in 2011. We are negotiating with the TCEQ 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)
April 2011	34,625	$28.03	34,625	—	$3.46 billion
May 2011	11,585	$27.28	11,585	—	$3.46 billion
June 2011	3,215	$25.06	3,215	—	$3.46 billion
Total	49,425	$27.66	49,425	—	$3.46 billion

(a) The shares reported in this column represent purchases settled in the second 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: August 9, 2011