VALERO ENERGY CORP/TX
Form 10-Q
November 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 September 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 October 31, 2011 was 559,726,988.

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)

	September 30, 2011 (Unaudited)	December 31, 2010
ASSETS		
Current assets:		
Cash and temporary cash investments	$2,829	$3,334
Receivables, net	7,509	4,583
Inventories	5,164	4,947
Income taxes receivable	5	343
Deferred income taxes	254	190
Prepaid expenses and other	109	121
Total current assets	15,870	13,518
Property, plant and equipment, at cost	31,066	28,921
Accumulated depreciation	(6,847)	(6,252)
Property, plant and equipment, net	24,219	22,669
Intangible assets, net	251	224
Deferred charges and other assets, net	1,343	1,210
Total assets	$41,683	$37,621
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of debt and capital lease obligations	$867	$822
Accounts payable	8,520	6,441
Accrued expenses	785	590
Taxes other than income taxes	1,053	671
Income taxes payable	136	3
Deferred income taxes	322	257
Total current liabilities	11,683	8,784
Debt and capital lease obligations, less current portion	6,781	7,515
Deferred income taxes	4,942	4,530
Other long-term liabilities	1,607	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	7,559	7,704
Treasury stock, at cost; 114,855,199 and 105,113,545 common shares	(6,491)	(6,462)
Retained earnings	15,347	13,388
Accumulated other comprehensive income	232	388
Total Valero Energy Corporation stockholders' equity	16,654	15,025
Noncontrolling interests	16	—
Total equity	16,670	15,025

Total liabilities and equity	$41,683	$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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating revenues (a)	$33,713	$21,015	$91,314	$60,069
Costs and expenses:				
Cost of sales	30,033	18,915	82,981	54,198
Operating expenses:				
Refining	870	753	2,427	2,210
Retail	177	169	508	484
Ethanol	103	96	302	267
General and administrative expenses	161	139	442	367
Depreciation and amortization expense	390	353	1,141	1,043
Asset impairment loss	—	—	—	2
Total costs and expenses	31,734	20,425	87,801	58,571
Operating income	1,979	590	3,513	1,498
Other income, net	1	17	28	29
Interest and debt expense, net of capitalized interest	(88)	(119)	(312)	(363)
Income from continuing operations before income tax expense	1,892	488	3,229	1,164
Income tax expense	689	185	1,178	421
Income from continuing operations	1,203	303	2,051	743
Income (loss) from discontinued operations, net of income taxes	—	(11)	(7)	19
Net income	1,203	292	2,044	762
Less: Net loss attributable to noncontrolling interests	—	—	(1)	—
Net income attributable to Valero Energy Corporation stockholders	$1,203	$292	$2,045	$762
Net income attributable to Valero Energy Corporation stockholders:				
Continuing operations	$1,203	$303	$2,052	$743
Discontinued operations	—	(11)	(7)	19
Total	$1,203	$292	$2,045	$762
Earnings per common share:				
Continuing operations	$2.12	$0.54	$3.61	$1.31
Discontinued operations	—	(0.02)	(0.01)	0.03
Total	$2.12	$0.52	$3.60	$1.34
Weighted-average common shares outstanding (in millions)	564	564	566	563
Earnings per common share – assuming dilution:				
Continuing operations	$2.11	$0.53	$3.59	$1.31
Discontinued operations	—	(0.02)	(0.01)	0.03
Total	$2.11	$0.51	$3.58	$1.34
Weighted-average common shares outstanding – assuming dilution (in millions)	569	568	572	567
Dividends per common share	$0.05	$0.05	$0.15	$0.15
Supplemental information:				
(a) Includes excise taxes on sales by our U.S. retail system	$229	$234	$670	$667

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)

	Nine Months Ended September 30, 2011	2010
Cash flows from operating activities:		
Net income	$2,044	$762
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	1,141	1,096
Noncash interest expense and other income, net	20	8
Asset impairment loss	—	2
Gain on sale of Delaware City Refinery assets	—	(92)
Stock-based compensation expense	34	32
Deferred income tax expense	393	285
Changes in current assets and current liabilities	840	592
Changes in deferred charges and credits and other operating activities, net	(144)	(63)
Net cash provided by operating activities	4,328	2,622
Cash flows from investing activities:		
Capital expenditures	(1,584)	(1,226)
Deferred turnaround and catalyst costs	(501)	(410)
Acquisition of Pembroke Refinery, net of cash acquired	(1,675)	—
Acquisition of pipeline and terminal facilities	(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	(24)	15
Net cash used in investing activities	(3,821)	(1,661)
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)
Purchase of common stock for treasury	(270)	(2)
Issuance of common stock in connection with stock-based compensation plans	42	12
Common stock dividends	(85)	(85)
Debt issuance costs	—	(10)
Contributions from noncontrolling interests	12	—
Other financing activities, net	17	5
Net cash provided by (used in) financing activities	(1,002)	547
Effect of foreign exchange rate changes on cash	(10)	19
Net increase (decrease) in cash and temporary cash investments	(505)	1,527
Cash and temporary cash investments at beginning of period	3,334	825
Cash and temporary cash investments at end of period	$2,829	$2,352

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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income	$1,203	$292	$2,044	$762
Other comprehensive income (loss):				
Foreign currency translation adjustment	(278)	100	(166)	63
Pension and other postretirement benefits:				
Net loss arising during the period, net of income tax benefit of $-, $-, $-, and $-	—	—	—	(21)
Net gain reclassified into income, net of income tax expense of $1, $2, $2, and $2	(1)	(2)	(3)	(4)
Net loss on pension and other postretirement benefits	(1)	(2)	(3)	(25)
Derivative instruments designated and qualifying as cash flow hedges:				
Net gain (loss) arising during the period, net of income tax (expense) benefit of $(7), $-, $(7), and $1	13	—	13	(1)
Net gain reclassified into income, net of income tax expense of $-, $13, $-, and $47	—	(24)	—	(88)
Net gain (loss) on cash flow hedges	13	(24)	13	(89)
Other comprehensive income (loss)	(266)	74	(156)	(51)
Comprehensive income	937	366	1,888	711
Less: Comprehensive loss attributable to noncontrolling interests	—	—	(1)	—
Comprehensive income attributable to Valero Energy Corporation stockholders	$937	$366	$1,889	$711

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 nine months ended September 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 nine months ended September 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 September 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.

Noncontrolling Interests

In connection with the acquisition of the Pembroke Refinery (see further discussion in Note 2), we acquired an 85 percent interest in Mainline Pipelines Limited (MLP). MLP owns a pipeline that distributes refined products from the Pembroke Refinery to terminals in the United Kingdom.

On January 21, 2011, we entered into a joint venture agreement with Darling Green Energy LLC, a subsidiary of Darling International, Inc., 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. 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 interests in MLP and DGD Holdings, we have included the financial statements of MLP and DGD Holdings in these consolidated financial statements and have separately disclosed the related noncontrolling interests.

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

Significant Accounting Policies
Reclassifications
As discussed in Note 2, we sold our Paulsboro Refinery in December 2010. As a result, the results of operations of the Paulsboro Refinery have been reclassified to discontinued operations for the three and nine months ended September 30, 2010.

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 $23 million and $68 million for the three and nine months ended September 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.

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

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

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 DISPOSITIONS

Meraux Acquisition
On October 1, 2011, we acquired the Meraux Refinery and related logistics assets for an initial payment of $586 million, including inventories of $261 million, from Murphy Oil Corporation, with the total purchase price funded from available cash. We expect to receive a favorable adjustment related to inventories in the fourth quarter of 2011 that will reduce the purchase price by approximately $40 million. The Meraux Refinery has a total throughput capacity of 135,000 barrels per day and is located in Meraux, Louisiana. This acquisition is referred to as the Meraux Acquisition.

The Meraux Acquisition is consistent with our general business strategy and complements our existing refining and marketing network.

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

Pembroke Acquisition
On August 1, 2011, we acquired 100 percent of the outstanding shares of Chevron Limited from a subsidiary of Chevron Corporation (Chevron), and we subsequently changed the name of Chevron Limited to Valero Energy Ltd. Valero Energy Ltd 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. Valero Energy Ltd also owns, directly and through various subsidiaries, an extensive network of marketing and logistics assets throughout the United Kingdom and Ireland. On the acquisition date, we initially paid $1.8 billion from available cash, of which $1.1 billion was for working capital. Subsequent to the acquisition date, the amounts paid have been favorably adjusted for working capital true-up adjustments (primarily inventory), with an adjusted purchase price of $1.675 billion, as outlined below. We expect final settlement by year end. 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.

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

The purchase price for the Pembroke Acquisition has been preliminarily allocated based on estimated fair values of the assets acquired and liabilities assumed at the acquisition date, pending the completion of an independent appraisal and other evaluations. The preliminary purchase price allocation as of September 30, 2011 was as follows (in millions):

Current assets, net of cash acquired	$2,217
Property, plant and equipment	777
Deferred charges and other assets	17
Intangible assets	50
Current liabilities, less current portion of debt and capital lease obligations	(1,294)
Debt and capital leases assumed, including current portion	(12)
Other long-term liabilities	(77)
Noncontrolling interest	(3)
Purchase price, net of cash acquired	$1,675

The acquired intangible assets are subject to amortization and have preliminary estimated useful lives of 15 years. These acquired intangible assets have been preliminarily assigned to the major intangible asset classes of royalties and licenses and wholesale dealer agreements.

During the three and nine months ended September 30, 2011, we recognized $18 million and $23 million, respectively, of costs related to the Pembroke Acquisition. These costs were expensed and are included in general and administrative expenses.

Our consolidated statements of income include the results of operations of the Pembroke Acquisition commencing on August 1, 2011. The operating revenues and income from continuing operations associated with the Pembroke Acquisition included in our consolidated statements of income for the three and nine months ended September 30, 2011, were as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating revenues	$3,028	N/A	$3,028	N/A
Income from continuing operations	19	N/A	19	N/A

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

The following pro forma financial information (in millions, except per share amounts) presents our consolidated results assuming the Pembroke Acquisition occurred on January 1, 2010. The pro forma financial information is not necessarily indicative of the results of future operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating revenues	$35,491	$24,594	$103,030	$70,638
Income from continuing operations attributable to Valero stockholders	1,196	306	1,941	767
Earnings per common share from continuing operations – basic	2.11	0.54	3.41	1.36
Earnings per common share from continuing operations – assuming dilution	2.10	0.54	3.39	1.35

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 September 30, 2011 or pro forma results of operations for the three and nine months ended September 30, 2011 and 2010. The consolidated statements of income for the three and nine months ended September 30, 2011 include the results of this acquisition from its acquisition date.

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.

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

Disposition of Paulsboro Refinery
In December 2010, we sold our Paulsboro Refinery to PBF Holding Company LLC (PBF Holding) for total proceeds of $707 million, including $361 million from the sale of working capital, resulting in a pre-tax loss of $980 million ($610 million after taxes). The sale proceeds consisted of $547 million of cash and a $160 million note secured by the Paulsboro Refinery. The note matures in December 2011 and bears interest at LIBOR plus 700 basis points. PBF Holding has the option to extend the note for six months; however, the interest rate for the additional six months will be LIBOR plus 900 basis points.

The results of operations of the Paulsboro Refinery are reflected in discontinued operations, and selected results prior to its sale are shown below (in millions).

	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Operating revenues	$1,195	$3,559
Loss before income taxes	(18)	(36)

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 this gain is presented in discontinued operations for the nine months ended September 30, 2010.

Results of operations of the Delaware City Refinery are reflected in discontinued operations, and selected results prior to its sale, excluding the gain on the sale, are shown below (in millions):

	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Operating revenues	$—	$—
Loss before income taxes	—	(33)

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

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 restarted our Aruba Refinery due to improvements in the U.S. and worldwide economies and the resulting improvement in refining industry fundamentals; however, we analyzed our Aruba Refinery for potential impairment as of September 30, 2011 because of its recent temporary shutdown, its negative operating cash flows subsequent to its restart, the sensitivity of its profitability to sour crude oil differentials, and our decision in July 2011 to renew our exploration of strategic alternatives for the refinery, which may include the sale of the refinery. We considered these matters in our impairment analysis and concluded that our Aruba Refinery was not impaired as of September 30, 2011. Our future cash flow estimates for the refinery are based on our expectation that refining industry fundamentals will continue to improve in connection with an increase in the demand for refined products. Should refining industry fundamentals fail to continue to improve or should we decide to sell the refinery, our future 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 $950 million as of September 30, 2011; therefore, an impairment loss could be material to our results of operations.

4. INVENTORIES

Inventories consisted of the following (in millions):

	September 30, 2011	December 31, 2010
Refinery feedstocks	$2,502	$2,225
Refined products and blendstocks	2,217	2,233
Ethanol feedstocks and products	130	201
Convenience store merchandise	102	101
Materials and supplies	213	187
Inventories	$5,164	$4,947

As of September 30, 2011 and December 31, 2010, the replacement cost (market value) of LIFO inventories exceeded their LIFO carrying amounts by approximately $7.1 billion and $6.1 billion, respectively.

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

5. DEBT
Non-Bank Debt
During the nine months ended September 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
- 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.

During the nine months ended September 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 $1.2 billion.

Bank Debt and 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 September 30, 2011 and December 31, 2010, our debt-to-capitalization ratio, calculated in accordance with the terms of the Revolver, was 22 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 nine months ended September 30, 2011 and 2010, we had no borrowings or repayments under our Revolver or the Canadian revolving credit facility. As of September 30, 2011 and December 31, 2010, we had no borrowings outstanding under the Revolver or the Canadian revolving credit facility.

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

	Borrowing Capacity	Expiration	Amounts Outstanding September 30, 2011	December 31, 2010
Letter of credit facility	$200	June 2012	$—	$—
Letter of credit facility	$300	June 2012	$300	$100
Revolver	$2,400	November 2012	$74	$399
Canadian revolving credit facility	C$115	December 2012	C$20	C$20

As of September 30, 2011 and December 31, 2010, we had $346 million and $176 million, respectively, of letters of credit outstanding under our uncommitted short-term bank credit facilities.

In connection with the Pembroke Acquisition, we assumed a €2.8 million short-term demand loan, which bears interest at EURIBOR plus a margin. We expect to repay the loan on or before February 2012.

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 September 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 nine months ended September 30, 2011. During the nine months ended September 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.

Capitalized Interest
Capitalized interest was $41 million and $25 million for the three months ended September 30, 2011 and 2010, respectively, and $101 million and $67 million for the nine months ended September 30, 2011 and 2010, respectively.

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6. COMMITMENTS AND CONTINGENCIES

Environmental Matters
The U.S. Environmental Protection Agency (EPA) 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 statewide 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 statewide cap-and-trade program will begin in 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.

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

Tax Matters

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

Litigation Matters

We are party to 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

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

	2011 Valero Stockholders' Equity	Non-controlling Interests	Total Equity	2010 Valero Stockholders' Equity	Non-controlling Interests	Total Equity
Balance at beginning of period	$15,025	$—	$15,025	$14,725	$—	$14,725
Net income (loss)	2,045	(1)	2,044	762	—	762
Dividends	(85)	—	(85)	(85)	—	(85)
Stock-based compensation expense	34	—	34	32	—	32
Tax deduction in excess of stock-based compensation expense	19	—	19	7	—	7
Transactions in connection with stock-based compensation plans:						
Stock issuances	42	—	42	12	—	12
Stock repurchases	(270)	—	(270)	(2)	—	(2)
Contributions from noncontrolling interest	—	14	14	—	—	—
Recognition of noncontrolling interest in connection with Pembroke Acquisition	—	3	3	—	—	—
Other comprehensive income (loss)	(156)	—	(156)	(51)	—	(51)
Balance at end of period	$16,654	$16	$16,670	$15,400	$—	$15,400

The noncontrolling interests relate to the ownership interests in MLP and DGD Holdings that are owned by parties unrelated to us, as discussed in Note 1.

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Treasury Stock
During the nine months ended September 30, 2011 and 2010, we purchased 13.6 million shares and 1.6 million shares, respectively, of our common stock in connection with the administration of our stock-based compensation plans. During the nine months ended September 30, 2011 and 2010, we issued 3.9 million and 1.6 million shares from treasury, respectively, for our stock-based compensation plans.

Common Stock Dividends
On October 27, 2011, our board of directors declared a regular quarterly cash dividend of $0.15 per common share payable on December 14, 2011 to holders of record at the close of business on November 16, 2011.

8. EMPLOYEE BENEFIT PLANS

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

	Pension Plans		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Three months ended September 30:				
Service cost	$28	$22	$4	$3
Interest cost	21	21	5	6
Expected return on plan assets	(28)	(28)	—	—
Amortization of:				
Prior service cost (credit)	1	1	(6)	(5)
Net loss	3	—	—	1
Net periodic benefit cost	$25	$16	$3	$5
Nine months ended September 30:				
Service cost	$73	$65	$9	$8
Interest cost	64	62	16	19
Expected return on plan assets	(84)	(84)	—	—
Amortization of:				
Prior service cost (credit)	2	2	(17)	(15)
Net loss	9	1	1	3
Net periodic benefit cost	$64	$46	$9	$15

During the nine months ended September 30, 2011 and 2010, we contributed $207 million and $54 million, respectively, 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 September 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		$1,203		$303
Less dividends paid:				
Common stock		28		28
Nonvested restricted stock		—		—
Undistributed earnings		$1,175		$275
Weighted-average common shares outstanding	3	564	3	564
Earnings per common share from continuing operations:				
Distributed earnings	$0.05	$0.05	$0.05	$0.05
Undistributed earnings	2.07	2.07	0.49	0.49
Total earnings per common share from continuing operations	$2.12	$2.12	$0.54	$0.54
Earnings per common share from continuing operations – assuming dilution:				
Net income attributable to Valero stockholders from continuing operations		$1,203		$303
Weighted-average common shares outstanding		564		564
Common equivalent shares:				
Stock options		3		3
Performance awards and unvested restricted stock		2		1
Weighted-average common shares outstanding – assuming dilution		569		568
Earnings per common share from continuing operations – assuming dilution		$2.11		$0.53

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	Nine Months Ended September 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		$2,052		$743
Less dividends paid:				
Common stock		85		85
Nonvested restricted stock		—		—
Undistributed earnings		$1,967		$658
Weighted-average common shares outstanding	3	566	3	563
Earnings per common share from continuing operations:				
Distributed earnings	$0.15	$0.15	$0.15	$0.15
Undistributed earnings	3.46	3.46	1.16	1.16
Total earnings per common share from continuing operations	$3.61	$3.61	$1.31	$1.31
Earnings per common share from continuing operations – assuming dilution:				
Net income attributable to Valero stockholders from continuing operations		$2,052		$743
Weighted-average common shares outstanding		566		563
Common equivalent shares:				
Stock options		4		3
Performance awards and unvested restricted stock		2		1
Weighted-average common shares outstanding – assuming dilution		572		567
Earnings per common share from continuing operations – assuming dilution		$3.59		$1.31

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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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Stock options	6	17	6	14

10. SEGMENT INFORMATION

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

	Refining	Retail	Ethanol	Corporate	Total
Three months ended September 30, 2011:					
Operating revenues from external customers	$29,177	$3,053	$1,483	$—	$33,713
Intersegment revenues	2,258	—	25	—	2,283
Operating income (loss)	1,947	97	107	(172)	1,979
Three months ended September 30, 2010:					
Operating revenues from external customers	17,811	2,360	844	—	21,015
Intersegment revenues	1,576	—	73	—	1,649
Operating income (loss)	590	105	47	(152)	590
Nine months ended September 30, 2011:					
Operating revenues from external customers	78,660	8,865	3,789	—	91,314
Intersegment revenues	6,566	—	125	—	6,691
Operating income (loss)	3,476	298	215	(476)	3,513
Nine months ended September 30, 2010:					
Operating revenues from external customers	51,104	6,893	2,072	—	60,069
Intersegment revenues	4,675	—	184	—	4,859
Operating income (loss)	1,479	285	139	(405)	1,498

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

	September 30, 2011	December 31, 2010
Refining	$35,541	$30,363
Retail	1,933	1,925
Ethanol	879	953
Corporate	3,330	4,380
Total consolidated assets	$41,683	$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):

	Nine Months Ended September 30, 2011	2010
Decrease (increase) in current assets:		
Receivables, net	$(1,963)	$(516)
Inventories	891	79
Income taxes receivable	333	787
Prepaid expenses and other	12	111
Increase (decrease) in current liabilities:		
Accounts payable	1,191	358
Accrued expenses	137	(51)
Taxes other than income taxes	99	(168)
Income taxes payable	140	(8)
Changes in current assets and current liabilities	$840	$592

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 the Pembroke Acquisition in August 2011 and 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 rates as of each balance sheet date.

During the nine months ended September 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 nine months ended September 30, 2010.

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

	Nine Months Ended September 30,	
	2011	2010
Interest paid in excess of amount capitalized	$276	$302
Income taxes paid (received), net	289	(645)

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 nine months ended September 30, 2010 and are summarized as follows (in millions):

Cash provided by (used in) operating activities:	
Paulsboro Refinery	$42
Delaware City Refinery	(76)
Cash used in investing activities:	
Paulsboro Refinery	(32)
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 September 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 September 30, 2011
Assets:					
Commodity derivative contracts	$6,764	$238	$—	$(6,734)	$268
Physical purchase contracts	—	(81)	—	—	(81)
Investments of nonqualified benefit plans	81	—	11	—	92
Other investments	—	—	—	—	—
Liabilities:					
Commodity derivative contracts	6,503	338	—	(6,734)	107
Nonqualified benefit plan obligations	34	—	—	—	34
RINs obligation	137	—	—	—	137

	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
Physical purchase contracts	—	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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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.
- Physical purchase contracts 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, and as disclosed in Note 13, some of these contracts are designated as hedging instruments. 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. We have elected to account for these investments at their fair values. 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 $228 million and $403 million with brokers under master netting arrangements are included in the fair value of the commodity derivatives reflected in Level 1 as of September 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 September 30:				
Balance at beginning of period	$11	$—	$10	$—
Purchases	—	5	—	—
Total losses included in earnings	—	(5)	—	—
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	$—	$(5)	$—	$—
Nine months ended September 30:				
Balance at beginning of period	$10	$—	$10	$—
Purchases	—	21	—	1
Total gains (losses) included in earnings	1	(21)	—	(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	$(21)	$—	$(1)

Nonrecurring Fair Value Measurements
As of September 30, 2011 and December 31, 2010, there were no assets or liabilities that were measured 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):

	September 30, 2011	December 31, 2010
Carrying amount (excluding capital leases)	$7,595	$8,300
Fair value	9,169	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 derivative. 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 hedges (derivative instruments 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 instruments are reflected in operating activities in the consolidated statements of cash flows for all periods presented.

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

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 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 derivative is described below.

Fair Value Hedges

Fair value hedges are used to hedge price volatility in 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 September 30, 2011, we had the following outstanding commodity derivative instruments that were entered into to hedge crude oil and refined product inventories and commodity derivative instruments related to the physical purchase of crude oil and refined products at a fixed price. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes in thousands of barrels).

Derivative Instrument	Notional Contract Volumes by Year of Maturity 2011
Crude oil and refined products:	
Futures – long	3,025
Futures – short	16,453
Physical purchase contracts – long	13,428

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

Cash Flow Hedges
Cash flow hedges are used to hedge price volatility in 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 September 30, 2011, we had the following outstanding commodity derivative instruments that were entered into to hedge forecasted purchases or sales of crude oil and refined products. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes in thousands of barrels).

	Notional Contract Volumes by Year of Maturity
Derivative Instrument	2012
Crude oil and refined products:	
Swaps – long	5,241
Swaps – short	5,241

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

Economic Hedges

Economic hedges represent commodity derivative instruments that are 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 September 30, 2011, we had the following outstanding commodity derivative instruments that were entered into as economic hedges and commodity derivative instruments related to the physical purchase of corn at a fixed price. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes in thousands of barrels, except those identified as corn contracts that are presented in thousands of bushels).

	Notional Contract Volumes by Year of Maturity		
Derivative Instrument	2011	2012	2013
Crude oil and refined products:			
Swaps – long	34,708	65,040	—
Swaps – short	33,890	65,040	—
Futures – long	200,076	40,388	—
Futures – short	192,292	41,219	—
Options – long	606	10	—
Options – short	600	—	—
Corn:			
Futures – long	22,325	8,405	—
Futures – short	41,300	23,980	260
Physical purchase contracts – long	12,166	10,991	265

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

Trading Derivatives
Our objective in entering into commodity derivative instruments for trading purposes is to take advantage of existing market conditions related to future results of operations and cash flows.

As of September 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	6,196	3,240
Swaps – short	6,196	3,240
Futures – long	66,365	15,868
Futures – short	66,389	15,831
Options – short	75	—
Natural gas:		
Futures – long	5,050	—
Futures – short	5,050	—
Corn:		
Swaps – long	—	1,050
Swaps – short	—	1,050
Futures – long	3,850	60
Futures – short	2,350	1,060

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 and European operations that are denominated in currencies other than the local (functional) currencies 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 September 30, 2011, we had commitments to purchase $475 million of U.S. dollars. These commitments matured on or before October 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 September 30, 2011 and December 31, 2010 (in millions) and the line items in the consolidated 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.

	Consolidated Balance Sheet Location	September 30, 2011	
		Asset Derivatives	Liability Derivatives
Derivatives designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$360	$237
Swaps	Receivables, net	46	40
Swaps	Accrued expenses	4	3
Total		$410	$280
Derivatives not designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$6,170	$6,266
Swaps	Receivables, net	6	5
Swaps	Prepaid expenses and other	2	1
Swaps	Accrued expenses	181	268
Options	Receivables, net	5	—
Options	Accrued expenses	—	21
Physical purchase contracts	Inventories	—	81
Total		$6,364	$6,642
Total derivatives		$6,774	$6,922

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

	Consolidated Balance Sheet Location	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
Physical purchase contracts	Inventories	17	—
Total		$3,137	$3,345
Total derivatives		$3,343	$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 September 30, 2011, we had net receivables related to derivative instruments of $1 million from counterparties in the refining industry and no amount of net receivables 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 September 30:							
Commodity contracts	Cost of sales	$170	$54	$(161)	$(56)	$9	$(2)
Nine months ended September 30:							
Commodity contracts	Cost of sales	219	253	(222)	(247)	(3)	6

For fair value hedges, no component of the derivative instruments' gains or losses was excluded from the assessment of hedge effectiveness for the three and nine months ended September 30, 2011 and 2010. No amounts were recognized in income for hedged firm commitments that no longer qualify as fair value hedges for the three and nine months ended September 30, 2011 and 2010.

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 September 30:								
Commodity contracts	$20	$—	Cost of sales	$—	$37	Cost of sales	$4	$—
Nine months ended September 30:								
Commodity contracts	20	(2)	Cost of sales	—	135	Cost of sales	4	—

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

For cash flow hedges, no component of the derivative instruments' gains or losses was excluded from the assessment of hedge effectiveness for the three and nine months ended September 30, 2011 and 2010. For the three and nine months ended September 30, 2011, cash flow hedges primarily related to forward sales of gasoline and distillates, and associated forward purchases of crude oil, with $13 million of cumulative after-tax gains on cash flow hedges remaining in accumulated other comprehensive income as of September 30, 2011. We estimate that $10 million of the deferred gains as of September 30, 2011 will be reclassified into cost of sales over the next 12 months as a result of hedged transactions that are forecasted to occur. For the three and nine months ended September 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.

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 September 30:			
Commodity contracts	Cost of sales	$9	$22
Foreign currency contracts	Cost of sales	41	(5)
Other contract	Cost of sales	29	—
Total		$79	$17
Nine months ended September 30:			
Commodity contracts	Cost of sales	$(362)	$(93)
Foreign currency contracts	Cost of sales	32	(2)
Other contract	Cost of sales	29	—
Total		$(301)	$(95)

The gain of $29 million on the other contract for the three and nine months ended September 30, 2011 is related to the difference between the fair value of inventories acquired in connection with the Pembroke Acquisition and the amount paid for such inventories based on the terms of the purchase agreement. The loss of $362 million on commodity contracts for the nine months ended September 30, 2011 includes a $542 million loss related to forward sales of refined products.

Trading Derivatives	Location of Gain or (Loss) Recognized in Income on Derivatives	Gain or (Loss) Recognized in Income on Derivatives	
		2011	2010
Three months ended September 30:			
Commodity contracts	Cost of sales	$3	$2
Nine months ended September 30:			
Commodity contracts	Cost of sales	17	7

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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, the United Kingdom, Ireland, 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 produce crude oil or consume refined products, including the U.S., Canada, Europe, 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, petrochemicals, and ethanol;
- 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 to the U.S., Canada, or the United Kingdom;
- 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, the pound sterling, and the Euro 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 third quarter of 2011, we reported net income attributable to Valero stockholders from continuing operations of $1.2 billion, or $2.11 per share, compared to $303 million, or $0.53 per share, for the third quarter of 2010. For the first nine months of 2011, we reported net income attributable to Valero stockholders from continuing operations of $2.1 billion, or $3.59 per share, compared to $743 million, or $1.31 per share for the first nine months of 2010. Included in the results for the first nine months of 2011 was a $542 million loss ($352 million after taxes, or $0.62 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 third quarter and first nine 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 September 30,		
	2011	2010	Change
Operating income (loss) by business segment:			
Refining	$1,947	$590	$1,357
Retail	97	105	(8)
Ethanol	107	47	60
Corporate	(172)	(152)	(20)
Total	$1,979	$590	$1,389

	Nine Months Ended September 30,		
	2011	2010	Change
Operating income (loss) by business segment:			
Refining	$3,476	$1,479	$1,997
Retail	298	285	13
Ethanol	215	139	76
Corporate	(476)	(405)	(71)
Total	$3,513	$1,498	$2,015

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 $4.1 billion and $4.0 billion, respectively, for the first nine months of 2011, which reflects an improvement in operating income of $2.6 billion and $2.5 billion, respectively, 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 third quarter of 2011 and the first nine months of 2011, versus the comparable 2010 periods.

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Our retail segment generated operating income of $97 million for the third quarter of 2011 compared to $105 million for the third quarter of 2010. This decrease of $8 million was due primarily to an increase of $8 million in the fuel margin generated by our Canadian retail operations, offset by a decrease of $10 million in the fuel margin generated by our U.S. retail operations and an increase of $8 million in operating expenses. For the first nine months of 2011, our retail segment generated $298 million of operating income compared to $285 million for the first nine months of 2010. The increase was primarily due to higher fuel margins and volumes in our Canadian operations, including a favorable impact from the strengthening of the Canadian dollar relative to the U.S. dollar.

Our ethanol segment generated operating income of $107 million for the third quarter of 2011 compared to $47 million for the third quarter of 2010, and it generated $215 million of operating income for the first nine months of 2011 compared to $139 million for the first nine months of 2010. The increase in operating income in both the third quarter and first nine months of 2011 was primarily due to improved operating margins combined with a full nine 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 and we subsequently changed the name of Chevron Limited to Valero Energy Ltd. Valero Energy Ltd 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. Valero Energy Ltd also owns, directly and through various subsidiaries, an extensive network of marketing and logistics assets throughout the United Kingdom and Ireland. On the acquisition date, we initially paid $1.8 billion from available cash, of which $1.1 billion was for working capital. Subsequent to the acquisition date, the amounts paid have been favorably adjusted for working capital true-up adjustments (primarily inventory), to an adjusted purchase price of $1.675 billion. We expect final settlement by year end. This acquisition is referred to as the Pembroke Acquisition.

On October 1, 2011, we acquired the Meraux Refinery and related logistics assets for an initial payment of $586 million, including inventories of $261 million, from Murphy Oil Corporation. The purchase price was funded from available cash. We expect to receive a favorable adjustment related to inventories in the fourth quarter of 2011 that will reduce the purchase price by approximately $40 million.

As of the date of the filing of this report, the financial markets continue to experience 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 September 30,		
	2011	2010	Change
Operating revenues	$33,713	$21,015	$12,698
Costs and expenses:			
Cost of sales (d)	30,033	18,915	11,118
Operating expenses:			
Refining	870	753	117
Retail (d)	177	169	8
Ethanol	103	96	7
General and administrative expenses	161	139	22
Depreciation and amortization expense:			
Refining	340	303	37
Retail	29	27	2
Ethanol	10	10	—
Corporate	11	13	(2)
Total costs and expenses	31,734	20,425	11,309
Operating income	1,979	590	1,389
Other income, net	1	17	(16)
Interest and debt expense, net of capitalized interest	(88)	(119)	31
Income from continuing operations before income tax expense	1,892	488	1,404
Income tax expense	689	185	504
Income from continuing operations	1,203	303	900
Income (loss) from discontinued operations, net of income taxes	—	(11)	11
Net income	1,203	292	911
Less: Net loss attributable to noncontrolling interests	—	—	—
Net income attributable to Valero stockholders	$1,203	$292	$911
Net income attributable to Valero stockholders:			
Continuing operations	$1,203	$303	$900
Discontinued operations	—	(11)	11
Total	$1,203	$292	$911
Earnings per common share – assuming dilution:			
Continuing operations	$2.11	$0.53	$1.58
Discontinued operations	—	(0.02)	0.02
Total	$2.11	$0.51	$1.60

See note references on page 47.

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

	Three Months Ended September 30,		
	2011	2010	Change
Refining (a) (b):			
Operating income	$1,947	$590	$1,357
Throughput margin per barrel (e)	$13.24	$8.13	$5.11
Operating costs per barrel:			
Operating expenses	3.65	3.71	(0.06)
Depreciation and amortization expense	1.43	1.50	(0.07)
Total operating costs per barrel	5.08	5.21	(0.13)
Operating income per barrel	$8.16	$2.92	$5.24
Throughput volumes (thousand barrels per day):			
Feedstocks:			
Heavy sour crude	540	443	97
Medium/light sour crude	455	402	53
Acidic sweet crude	150	51	99
Sweet crude	739	708	31
Residuals	310	239	71
Other feedstocks	123	113	10
Total feedstocks	2,317	1,956	361
Blendstocks and other	275	247	28
Total throughput volumes	2,592	2,203	389
Yields (thousand barrels per day):			
Gasolines and blendstocks	1,196	1,088	108
Distillates	894	766	128
Other products (f)	519	381	138
Total yields	2,609	2,235	374

See note references on page 47.

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

	Three Months Ended September 30,		
	2011	2010	Change
Gulf Coast:			
Operating income	$1,167	$388	$779
Throughput volumes (thousand barrels per day)	1,522	1,336	186
Throughput margin per barrel (e)	$13.08	$8.34	$4.74
Operating costs per barrel:			
Operating expenses	3.31	3.65	(0.34)
Depreciation and amortization expense	1.43	1.54	(0.11)
Total operating costs per barrel	4.74	5.19	(0.45)
Operating income per barrel	$8.34	$3.15	$5.19
Mid-Continent:			
Operating income	$586	$131	$455
Throughput volumes (thousand barrels per day)	400	422	(22)
Throughput margin per barrel (e)	$22.27	$8.06	$14.21
Operating costs per barrel:			
Operating expenses	4.76	3.34	1.42
Depreciation and amortization expense	1.59	1.33	0.26
Total operating costs per barrel	6.35	4.67	1.68
Operating income per barrel	$15.92	$3.39	$12.53
North Atlantic (a) (b):			
Operating income	$65	$36	$29
Throughput volumes (thousand barrels per day)	386	193	193
Throughput margin per barrel (e)	$5.46	$6.04	$(0.58)
Operating costs per barrel:			
Operating expenses	2.91	2.75	0.16
Depreciation and amortization expense	0.74	1.30	(0.56)
Total operating costs per barrel	3.65	4.05	(0.40)
Operating income per barrel	$1.81	$1.99	$(0.18)
West Coast:			
Operating income	$129	$35	$94
Throughput volumes (thousand barrels per day)	284	252	32
Throughput margin per barrel (e)	$11.96	$8.66	$3.30
Operating costs per barrel:			
Operating expenses	4.94	5.42	(0.48)
Depreciation and amortization expense	2.08	1.74	0.34
Total operating costs per barrel	7.02	7.16	(0.14)
Operating income per barrel	$4.94	$1.50	$3.44
Total refining operating income	$1,947	$590	$1,357

See note references on page 47.

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

	Three Months Ended September 30,		
	2011	2010	Change
Feedstocks:			
Louisiana Light Sweet (LLS) crude oil	$112.21	$78.66	$33.55
LLS less West Texas Intermediate (WTI) crude oil	22.47	2.58	19.89
LLS less Alaska North Slope (ANS) crude oil	0.60	3.03	(2.43)
LLS less Brent crude oil	(1.43)	1.73	(3.16)
LLS less Mars crude oil	2.53	3.96	(1.43)
LLS less Maya crude oil	13.48	11.04	2.44
WTI crude oil	89.74	76.08	13.66
WTI less Mars crude oil	(19.94)	1.38	(21.32)
WTI less Maya crude oil	(8.99)	8.46	(17.45)
Products:			
Gulf Coast:			
Conventional 87 gasoline less LLS	$8.20	$4.35	$3.85
Ultra-low-sulfur diesel less LLS	14.19	9.12	5.07
Propylene less LLS	12.46	2.61	9.85
Conventional 87 gasoline less WTI	30.67	6.93	23.74
Ultra-low-sulfur diesel less WTI	36.66	11.70	24.96
Propylene less WTI	34.93	5.19	29.74
Mid-Continent:			
Conventional 87 gasoline less WTI	32.11	9.20	22.91
Ultra-low-sulfur diesel less WTI	38.34	13.20	25.14
North Atlantic:			
Conventional 87 gasoline less Brent	7.48	5.85	1.63
Ultra-low-sulfur diesel less Brent	14.55	12.16	2.39
Conventional 87 gasoline less WTI	31.38	6.70	24.68
Ultra-low-sulfur diesel less WTI	38.45	13.01	25.44
West Coast:			
CARBOB 87 gasoline less ANS	10.27	16.96	(6.69)
CARB diesel less ANS	15.77	15.10	0.67
CARBOB 87 gasoline less WTI	32.14	16.51	15.63
CARB diesel less WTI	37.64	14.65	22.99
New York Harbor corn crush (dollars per gallon)	0.36	0.43	(0.07)

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See note references on page 47.

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

	Three Months Ended September 30,		
	2011	2010	Change
Retail–U.S.: (d)			
Operating income	$59	$72	$(13)
Company-operated fuel sites (average)	994	990	4
Fuel volumes (gallons per day per site)	5,168	5,204	(36)
Fuel margin per gallon	$0.155	$0.176	$(0.021)
Merchandise sales	$324	$322	$2
Merchandise margin (percentage of sales)	29.2 %	28.8 %	0.4 %
Margin on miscellaneous sales	$22	$21	$1
Operating expenses	$111	$108	$3
Depreciation and amortization expense	$19	$18	$1
Retail–Canada: (d)			
Operating income	$38	$33	$5
Fuel volumes (thousand gallons per day)	3,214	3,214	—
Fuel margin per gallon	$0.273	$0.247	$0.026
Merchandise sales	$72	$66	$6
Merchandise margin (percentage of sales)	29.4 %	30.4 %	(1)%
Margin on miscellaneous sales	$11	$10	$1
Operating expenses	$66	$61	$5
Depreciation and amortization expense	$10	$9	$1
Ethanol (c):			
Operating income	$107	$47	$60
Production (thousand gallons per day)	3,272	3,100	172
Gross margin per gallon of production (e)	$0.73	$0.54	$0.19
Operating costs per gallon of production:			
Operating expenses	0.34	0.34	—
Depreciation and amortization expense	0.04	0.03	0.01
Total operating costs per gallon of production	0.38	0.37	0.01
Operating income per gallon of production	$0.35	$0.17	$0.18

See note references on page 47.

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The following notes relate to references on pages 42 through 46.

(a) The information presented for the three months ended September 30, 2011 includes the results of operations of our refinery in Wales, United Kingdom (Pembroke Refinery), including the related marketing and logistics business, from the date of its acquisition, August 1, 2011, through September 30, 2011. In addition, the refining segment and North Atlantic region operating highlights for the three months ended September 30, 2011 include the Pembroke Refinery.

(b) 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 September 30, 2010. In addition, the refining segment and North Atlantic region operating highlights exclude the Paulsboro Refinery for the three months ended September 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 $23 million for the three months ended September 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 September 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 North Atlantic (formerly known as Northeast) region includes the Pembroke and Quebec City Refineries; 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 60 percent (or $12.7 billion) for the third quarter of 2011 compared to the third 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. The higher throughput volumes resulted primarily from the incremental throughput of 178,000 barrels per day[1] ($3.0 billion of revenue) from the Pembroke Refinery, which was acquired on August 1, 2011, and throughput of 182,000 barrels per day ($1.8 billion of revenue) from the Aruba Refinery, which restarted operations in January 2011. Both operating income and income from continuing operations before taxes increased $1.4 billion for the third quarter of 2011 compared to amounts reported for the third quarter of 2010 primarily due to a $1.4 billion increase in refining segment operating income discussed below.

[1]Calculated based on throughput volumes of the Pembroke Refinery from the date of acquisition (August 1, 2011), divided by the number of days during the third quarter of 2011.

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Refining

Refining segment operating income more than tripled (a $1.4 billion increase) from $590 million for the third quarter of 2010 to $1.9 billion for the third quarter of 2011. The $1.4 billion improvement in operating income was due to a $1.5 billion increase in refining margin, offset by a $117 million increase in operating expenses.

The $1.5 billion increase in refining margin was primarily due to a 63 percent increase in throughput margin per barrel (a $5.11 per barrel increase between the comparable periods), and this increase was largely driven by an improvement in gasoline and distillate margins in most of our refining regions, primarily the Mid-Continent and Gulf Coast refining regions, as further explained below.

- The WTI-based benchmark reference margin for Mid-Continent conventional 87 gasoline was $32.11 per barrel for the third quarter of 2011, compared to $9.20 per barrel for the third quarter of 2010, representing a favorable increase of $22.91 per barrel. In addition, the WTI-based benchmark reference margin for Mid-Continent ultra-low sulfur diesel (a type of distillate) was $38.34 per barrel for the third quarter of 2011, compared to $13.20 per barrel for the third quarter of 2010, representing a favorable increase of $25.14 per barrel. We estimate that these increases in gasoline and distillate margins per barrel had a positive impact to our refining margin of approximately $500 million and $300 million, respectively, quarter versus quarter. The increases in the gasoline and distillate benchmark reference margins in the Mid-Continent region are primarily due to the substantial discount in the price of WTI crude oil, the primary type of crude oil processed by our Mid-Continent refineries, versus LLS-type crude oils. Historically, the price of WTI crude oil has tracked LLS crude oil, but 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 crude oil has resulted in WTI crude oil currently being priced at a significant discount to LLS crude oil.
- The LLS-based benchmark reference margin for Gulf Coast conventional 87 gasoline was $8.20 per barrel for the third quarter of 2011, compared to $4.35 per barrel for the third quarter of 2010, representing a favorable increase of $3.85 per barrel. In addition, the LLS-based benchmark reference margin for Gulf Coast ultra-low sulfur diesel was $14.19 per barrel for the third quarter of 2011, compared to $9.12 per barrel for the third quarter of 2010, representing a favorable increase of $5.07 per barrel. We estimate that these increases in gasoline and distillate margins per barrel had a positive impact to our refining margin of approximately $200 million and $250 million, respectively, quarter versus quarter. The increases in the gasoline and distillate benchmark reference margins are supported by increased exports of gasoline and distillate as well as an increase in demand for distillates.
- In addition, our system benefited from the increase in the discount of the price of heavy sour crude oils as compared to the price of sweet crude oils. For example, Maya crude oil, which is a type of heavy sour crude oil, sold at a discount of $13.48 per barrel to LLS crude oil, which is a type of sweet crude oil, during the third quarter of 2011. This compares to a discount of $11.04 per barrel during the third quarter of 2010, representing a favorable increase of $2.44 per barrel. We estimate that the increase in the discounts for all types of sour crude oil that we process had a positive impact to our refining margin of approximately $120 million, quarter versus quarter.

The increase of $117 million in operating expenses discussed above was primarily due to $50 million in operating expenses incurred by the Pembroke Refinery, which was acquired on August 1, 2011. The remaining increase in refining operating expenses of $67 million was primarily due to a $34 million increase in maintenance expenses and a $38 million increase in chemicals and catalyst costs.

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Retail

Retail segment operating income was $97 million for the third quarter of 2011 compared to $105 million for the third quarter of 2010. This 8 percent (or $8 million) decrease was due primarily to an increase of $8 million in the fuel margin generated by our Canadian retail operations offset by a decrease of $10 million in the fuel margin generated by our U.S. retail operations and an increase of $8 million in operating expenses between the quarters.

Ethanol

Ethanol segment operating income was $107 million for the third quarter of 2011 compared to $47 million for the third quarter of 2010. The $60 million increase in operating income was primarily due to a $68 million increase in gross margin, partially offset by a $7 million increase in operating expenses.

The increase in gross margin was due to an increase in ethanol production (a 172,000 gallon per day increase between the comparable periods), which resulted from higher utilization rates and increased yield from the corn feedstock that we processed during the third quarter of 2011, and a 35 percent increase in the gross margin per gallon of ethanol production (a $0.19 per gallon increase between the comparable periods).

The increase in operating expenses was due primarily to a $5 million increase in energy costs and chemical expenses.

Corporate Expenses and Other

General and administrative expenses increased $22 million from the third quarter of 2010 to the third quarter of 2011 primarily due to $18 million in costs incurred in connection with the Pembroke Acquisition.

“Other income, net” for the third quarter of 2011 decreased $16 million from the third quarter of 2010 primarily due to a $12 million decrease in investment income earned on the plan assets of certain of our non-qualified benefit plans and earnings of $4 million in the third quarter of 2010 related to our joint venture investment in Cameron Highway Oil Pipeline Company, which did not recur due to the sale of our ownership interest in that joint venture in the fourth quarter of 2010.

“Interest and debt expense, net of capitalized interest” for the third quarter of 2011 decreased $31 million from the third quarter of 2010. This decrease is primarily due to a $16 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 combined with a $7 million favorable impact from a decrease in average borrowings and an $8 million favorable impact resulting from the successful resolution of a tax contingency.

Income tax expense increased $504 million from the third quarter of 2010 to the third quarter of 2011 mainly as a result of higher operating income in 2011.

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

	Nine Months Ended September 30,		
	2011	2010	Change
Operating revenues	$91,314	$60,069	$31,245
Costs and expenses:			
Cost of sales (d) (e)	82,981	54,198	28,783
Operating expenses:			
Refining	2,427	2,210	217
Retail (d)	508	484	24
Ethanol	302	267	35
General and administrative expenses	442	367	75
Depreciation and amortization expense:			
Refining	995	898	97
Retail	84	80	4
Ethanol	28	27	1
Corporate	34	38	(4)
Asset impairment loss	—	2	(2)
Total costs and expenses	87,801	58,571	29,230
Operating income	3,513	1,498	2,015
Other income, net	28	29	(1)
Interest and debt expense, net of capitalized interest	(312)	(363)	51
Income from continuing operations before income tax expense	3,229	1,164	2,065
Income tax expense	1,178	421	757
Income from continuing operations	2,051	743	1,308
Income (loss) from discontinued operations, net of income taxes	(7)	19	(26)
Net income	2,044	762	1,282
Less: Net loss attributable to noncontrolling interests	(1)	—	(1)
Net income attributable to Valero stockholders	$2,045	$762	$1,283
Net income attributable to Valero stockholders:			
Continuing operations	$2,052	$743	$1,309
Discontinued operations	(7)	19	(26)
Total	$2,045	$762	$1,283
Earnings per common share – assuming dilution:			
Continuing operations	$3.59	$1.31	$2.28
Discontinued operations	(0.01)	0.03	(0.04)
Total	$3.58	$1.34	$2.24

See note references on page 55.

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

	Nine Months Ended September 30,		
	2011	2010	Change
Refining (a) (b):			
Operating income (e)	$3,476	$1,479	$1,997
Throughput margin per barrel (e) (f)	$10.80	$7.97	$2.83
Operating costs per barrel:			
Operating expenses	3.80	3.84	(0.04)
Depreciation and amortization expense	1.56	1.56	—
Total operating costs per barrel	5.36	5.40	(0.04)
Operating income per barrel	$5.44	$2.57	$2.87
Throughput volumes (thousand barrels per day):			
Feedstocks:			
Heavy sour crude	455	452	3
Medium/light sour crude	415	399	16
Acidic sweet crude	117	51	66
Sweet crude	695	655	40
Residuals	284	195	89
Other feedstocks	122	115	7
Total feedstocks	2,088	1,867	221
Blendstocks and other	252	241	11
Total throughput volumes	2,340	2,108	232
Yields (thousand barrels per day):			
Gasolines and blendstocks	1,069	1,046	23
Distillates	793	695	98
Other products (g)	491	392	99
Total yields	2,353	2,133	220

See note references on page 55.

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

	Nine Months Ended September 30,		
	2011	2010	Change
Gulf Coast:			
Operating income (e)	$2,064	$1,027	$1,037
Throughput volumes (thousand barrels per day)	1,418	1,268	150
Throughput margin per barrel (e) (f)	$10.48	$8.35	$2.13
Operating costs per barrel:			
Operating expenses	3.62	3.78	(0.16)
Depreciation and amortization expense	1.53	1.60	(0.07)
Total operating costs per barrel	5.15	5.38	(0.23)
Operating income per barrel	$5.33	$2.97	$2.36
Mid-Continent:			
Operating income (e)	$1,146	$271	$875
Throughput volumes (thousand barrels per day)	401	392	9
Throughput margin per barrel (e) (f)	$16.18	$7.59	$8.59
Operating costs per barrel:			
Operating expenses	4.14	3.63	0.51
Depreciation and amortization expense	1.56	1.42	0.14
Total operating costs per barrel	5.70	5.05	0.65
Operating income per barrel	$10.48	$2.54	$7.94
North Atlantic (a) (b):			
Operating income	$104	$81	$23
Throughput volumes (thousand barrels per day)	268	189	79
Throughput margin per barrel (f)	$5.32	$6.01	$(0.69)
Operating costs per barrel:			
Operating expenses	2.92	2.98	(0.06)
Depreciation and amortization expense	0.98	1.47	(0.49)
Total operating costs per barrel	3.90	4.45	(0.55)
Operating income per barrel	$1.42	$1.56	$(0.14)
West Coast:			
Operating income (e)	$162	$102	$60
Throughput volumes (thousand barrels per day)	253	259	(6)
Throughput margin per barrel (e) (f)	$9.87	$8.14	$1.73
Operating costs per barrel:			
Operating expenses	5.21	5.08	0.13
Depreciation and amortization expense	2.31	1.62	0.69
Total operating costs per barrel	7.52	6.70	0.82
Operating income per barrel	$2.35	$1.44	$0.91
Operating income for regions above	$3,476	$1,481	$1,995
Asset impairment loss applicable to refining	—	(2)	2
Total refining operating income	$3,476	$1,479	$1,997

See note references on page 55.

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

	Nine Months Ended September 30,		
	2011	2010	Change
Feedstocks:			
LLS crude oil	$111.73	$79.35	$32.38
LLS less WTI	16.34	1.83	14.51
LLS less ANS crude oil	2.44	2.27	0.17
LLS less Brent crude oil	(0.82)	2.14	(2.96)
LLS less Mars crude oil	4.05	3.39	0.66
LLS less Maya crude oil	14.58	10.88	3.70
WTI crude oil	95.39	77.52	17.87
WTI less Mars crude oil	(12.29)	1.56	(13.85)
WTI less Maya crude oil	(1.76)	9.05	(10.81)
Products:			
Gulf Coast:			
Conventional 87 gasoline less LLS	$7.43	$6.26	$1.17
Ultra-low-sulfur diesel less LLS	13.09	8.61	4.48
Propylene less LLS	19.33	7.80	11.53
Conventional 87 gasoline less WTI	23.77	8.09	15.68
Ultra-low-sulfur diesel less WTI	29.43	10.44	18.99
Propylene less WTI	35.67	9.63	26.04
Mid-Continent:			
Conventional 87 gasoline less WTI	24.79	8.77	16.02
Ultra-low-sulfur diesel less WTI	30.75	11.06	19.69
North Atlantic:			
Conventional 87 gasoline less Brent	6.29	8.33	(2.04)
Ultra-low-sulfur diesel less Brent	14.04	12.15	1.89
Conventional 87 gasoline less WTI	23.45	8.02	15.43
Ultra-low-sulfur diesel less WTI	31.20	11.84	19.36
West Coast:			
CARBOB 87 gasoline less ANS	13.39	14.97	(1.58)
CARB diesel less ANS	18.56	12.95	5.61
CARBOB 87 gasoline less WTI	27.29	14.53	12.76
CARB diesel less WTI	32.46	12.51	19.95
New York Harbor corn crush (dollars per gallon)	0.17	0.41	(0.24)

See note references on page 55.

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

	Nine Months Ended September 30,		
	2011	2010	Change
Retail–U.S.: (d)			
Operating income	$165	$181	$(16)
Company-operated fuel sites (average)	994	990	4
Fuel volumes (gallons per day per site)	5,053	5,115	(62)
Fuel margin per gallon	$0.146	$0.158	$(0.012)
Merchandise sales	$930	$910	$20
Merchandise margin (percentage of sales)	28.6%	28.4%	0.2%
Margin on miscellaneous sales	$66	$65	$1
Operating expenses	$312	$306	$6
Depreciation and amortization expense	$56	$54	$2
Retail–Canada: (d)			
Operating income	$133	$104	$29
Fuel volumes (thousand gallons per day)	3,210	3,131	79
Fuel margin per gallon	$0.303	$0.263	$0.040
Merchandise sales	$197	$179	$18
Merchandise margin (percentage of sales)	29.6%	30.3%	(0.7)%
Margin on miscellaneous sales	$33	$29	$4
Operating expenses	$196	$178	$18
Depreciation and amortization expense	$28	$26	$2
Ethanol (c):			
Operating income	$215	$139	$76
Production (thousand gallons per day)	3,317	2,943	374
Gross margin per gallon of production (f)	$0.60	$0.54	$0.06
Operating costs per gallon of production:			
Operating expenses	0.33	0.33	—
Depreciation and amortization expense	0.03	0.04	(0.01)
Total operating costs per gallon of production	0.36	0.37	(0.01)
Operating income per gallon of production	$0.24	$0.17	$0.07

See note references on page 55.

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The following notes relate to references on pages 50 through 54.

(a) The information presented for the nine months ended September 30, 2011 includes the results of operations of our Pembroke Refinery, including the related marketing and logistics business, from the date of its acquisition, August 1, 2011, through September 30, 2011. In addition, the refining segment and North Atlantic region operating highlights for the nine months ended September 30, 2011 include the Pembroke Refinery.

(b) In December 2010, we sold our Paulsboro Refinery to PBF Holding Company LLC and 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 these refineries have been presented as discontinued operations for the nine months ended September 30, 2010. In addition, the refining segment and North Atlantic region operating highlights exclude these refineries for nine months ended September 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 $68 million for the nine months ended September 30, 2010 have been reclassified from retail operating expenses to cost of sales. The Retail–U.S. and Retail–Canada operating highlights for the nine months ended September 30, 2010 have been restated to reflect this reclassification.

(e) Cost of sales for the nine months ended September 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 an $0.85 reduction in refining throughput margin per barrel for the nine months ended September 30, 2011, and is allocated to refining operating income by region, excluding the North Atlantic, based on relative throughput volumes for each region as follows: Gulf Coast- $372 million, or $0.96 per barrel; Mid-Continent- $122 million, or $1.11 per barrel; and West Coast- $48 million, or $0.69 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 North Atlantic region includes the Pembroke and Quebec City Refineries; 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 52 percent (or $31.2 billion) for the first nine months of 2011 compared to the first nine 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. The higher throughput volumes resulted primarily from the incremental throughput of 60,000 barrels per day[1] ($3.0 billion of revenue) from the Pembroke Refinery, which was acquired on August 1, 2011, and throughput of 161,000 barrels per day ($4.2 billion of revenue) from the Aruba Refinery, which restarted operations in January 2011. Operating income increased $2.0 billion and income from continuing operations before taxes increased $2.1 billion for the first nine months of 2011 compared to amounts reported for the first nine months of 2010 primarily due to a $2.0 billion increase in refining segment operating income discussed below.

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[1]Calculated based on throughput volumes of the Pembroke Refinery from the date of acquisition (August 1, 2011), divided by the number of days during the nine months ended September 30, 2011.

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Refining

Refining segment operating income more than doubled (a $2.0 billion increase) from $1.5 billion for the first nine months of 2010 to $3.5 billion for the first nine months of 2011. The $2.0 billion improvement in operating income was due to a $2.8 billion increase in refining margin, offset by a $542 million first quarter loss on forward sales of refined products and a $217 million increase in operating expenses.

The $2.8 billion increase in refining margin was primarily due to a 46 percent increase in throughput margin per barrel (a $3.68 per barrel increase between the comparable periods, consisting of the increase of $2.83 per barrel adjusted for the $0.85 per barrel impact of the $542 million loss discussed above). This increase in refining margin was largely driven by an improvement in gasoline and distillate margins in most of our refining regions, especially the Mid-Continent and Gulf Coast refining regions, as further explained below.

- The WTI-based benchmark reference margin for Mid-Continent conventional 87 gasoline was $24.79 per barrel for the first nine months of 2011, compared to $8.77 per barrel for the first nine months of 2010, representing a favorable increase of $16.02 per barrel. In addition, the WTI-based benchmark reference margin for Mid-Continent ultra-low sulfur diesel (a type of distillate) was $30.75 per barrel for the first nine months of 2011, compared to $11.06 per barrel for the first nine months of 2010, representing a favorable increase of $19.69 per barrel. We estimate that these increases in gasoline and distillate margins per barrel had a positive impact to our refining margin of approximately $900 million and $800 million, respectively, nine months versus nine months. The increases in the gasoline and distillate benchmark reference margins in the Mid-Continent region are primarily due to the substantial discount in the price of WTI crude oil, the primary type of crude oil processed by our Mid-Continent refineries, versus LLS-type crude oils. Historically, the price of WTI crude oil has tracked LLS crude oil, but 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 crude oil has resulted in WTI crude oil currently being priced at a significant discount to LLS crude oil.

- The LLS-based benchmark reference margin for Gulf Coast conventional 87 gasoline was $7.43 per barrel for the first nine months of 2011, compared to $6.26 per barrel for the first nine months of 2010, representing a favorable increase of $1.17 per barrel. In addition, the LLS-based benchmark reference margin for Gulf Coast ultra-low sulfur diesel was $13.09 per barrel for the first nine months of 2011, compared to $8.61 per barrel for the first nine months of 2010, representing a favorable increase of $4.48 per barrel. We estimate that these increases in gasoline and distillate margins per barrel had a positive impact to our refining margin of approximately $200 million and $600 million, respectively, nine months versus nine months. The increases in the gasoline and distillate benchmark reference margins are supported by increased exports of gasoline and distillate as well as an increase in demand for distillates.

- In addition, our system benefited from the increase in the discount of the price of heavy sour crude oils as compared to the price of sweet crude oils. For example, Maya crude oil, which is a type of heavy 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 first nine months of 2011. This compares to a discount of $10.88 per barrel during the first nine months of 2010, representing a favorable increase of $3.70 per barrel. We estimate that the increase in the discounts for all types of sour crude oil that we process had a positive impact to our refining margin of approximately $450 million, nine months versus nine months.

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The increase of $217 million in operating expenses discussed above was partially due to $50 million in operating expenses incurred by the Pembroke Refinery, which was acquired on August 1, 2011. The remaining increase of operating expenses of $167 million was primarily due to a $58 million increase in maintenance expenses, a $64 million increase in employee-related expenses, and a $76 million increase in chemicals and catalyst costs.

Retail

Retail segment operating income was $298 million for the first nine months of 2011 compared to $285 million for the first nine months of 2010. This 5 percent (or $13 million) increase was due to an increase in fuel margins of $23 million primarily from our Canadian operations, including a favorable impact from the strengthening of the Canadian dollar relative to the U.S. dollar, and an increase in merchandise margins of $12 million, offset by increased operating expenses of $24 million.

Ethanol

Ethanol segment operating income was $215 million for the first nine months of 2011 compared to $139 million for the first nine months of 2010. The $76 million increase in operating income was primarily due to a $113 million increase in gross margin, partially offset by a $35 million increase in operating expenses.

Gross margin increased from the first nine months of 2010 to the first nine months of 2011 due to an increase in ethanol production (a 374,000 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 and increased yields during 2011 combined with a $0.06 per gallon increase in the ethanol gross margin .

The increase in operating expenses was primarily due to $25 million of additional expenses related to the operation of the three ethanol plants we acquired in the first quarter of 2010 for a full nine months in 2011.

Corporate Expenses and Other

General and administrative expenses increased $75 million from the first nine months of 2010 to the first nine months of 2011 due to a $16 million increase in variable compensation expense, $23 million in costs incurred in connection in with the Pembroke Acquisition, and 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.

“Interest and debt expense, net of capitalized interest” for the first nine months of 2011 decreased $51 million from the first nine months of 2010. This decrease is primarily due to an increase of $34 million in capitalized interest due to a corresponding increase in capital expenditures between the nine-month periods and the resumption of construction activity on previously suspended projects combined with favorable impacts from the decrease in average borrowings of $12 million and the decrease in average interest rates of $3 million.

Income tax expense increased $757 million from the first nine months of 2010 to the first nine 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 nine 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 $19 million for the first nine months of 2010 represents a $58 million after-tax gain on the sale of the shutdown refinery assets at Delaware City, offset by a $39 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 Nine Months Ended September 30, 2011 and 2010

Net cash provided by operating activities for the first nine months of 2011 was $4.3 billion compared to $2.6 billion for the first nine months of 2010. The increase in cash generated from operating activities was primarily due to a $248 million favorable effect from changes in working capital between the periods, combined with the $2.0 billion increase in operating income discussed above under "RESULTS OF OPERATIONS." Changes in cash provided by or used for working capital during the first nine months of 2011 and 2010 are shown in Note 11 of Condensed Notes to Consolidated Financial Statements.

The net cash provided by operating activities during the first nine months of 2011 combined with $505 million from available cash on hand were used mainly to:

- fund $2.1 billion of capital expenditures and deferred turnaround and catalyst costs;
- purchase the Pembroke Refinery and the related marketing and logistics business for $1.7 billion,
- 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;
- purchase our common stock for $270 million; and
- pay common stock dividends of $85 million.

The net cash provided by operating activities during the first nine months of 2010, combined with $1.2 billion of net 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 $1.6 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 $85 million; and
- increase available cash on hand by $1.5 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 nine months ended September 30, 2010 and are summarized as follows (in millions):

Cash provided by (used in) operating activities:		
Paulsboro Refinery	$42	
Delaware City Refinery	(76	)
Cash used in investing activities:		
Paulsboro Refinery	(32	)
Delaware City Refinery	—	

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Capital Investments

Our operations, especially those of our refining segment, are highly capital intensive. Each of our refineries is comprised of a large base of assets, consisting of a series of interconnected, highly integrated and interdependent crude oil processing facilities and supporting logistical infrastructure (Units), and these Units are continuously improved. Improvements consist of the addition of new Units and betterments of existing Units, and the cost of these improvements is significant. We have historically acquired our refineries at amounts significantly below their replacement costs, whereas our improvements are made at full replacement value. As such, the costs for improving our refinery assets increase over time and are significant in relation to the amounts we paid to acquire our refineries. We plan for these improvements by developing a multi-year capital program that is updated and revised based on changing internal and external factors.

We make improvements to our refineries in order to maintain and enhance their operating reliability, to meet environmental obligations with respect to reducing emissions and removing prohibited elements from the products we produce, or to enhance their profitability. Reliability and environmental improvements generally do not increase the throughput capacities of our refineries. Improvements that enhance refinery profitability may increase throughput capacity, but many of these improvements allow our refineries to process higher volumes of sour crude oil, which lowers our feedstock costs, and to further refine crude oil into products with higher market values. Therefore, many of our improvements do not increase throughput capacity significantly.

During the nine months ended September 30, 2011, we expended $1.6 billion for capital expenditures primarily related to improvements to our refineries. We also expended $501 million for deferred turnaround and catalyst costs. Capital expenditures for the nine months ended September 30, 2011 included $168 million of costs related to environmental projects.

For 2011, we expect to incur $3.2 billion for capital investments, including $2.5 billion for capital expenditures primarily related to improvements to our refineries and $650 million for deferred turnaround and catalyst costs. The $2.5 billion for capital expenditures includes $250 million for environmental projects, but excludes expenditures related to strategic business acquisitions.

Contractual Obligations

As of September 30, 2011, our contractual obligations included debt, capital lease obligations, operating leases, purchase obligations, and other long-term liabilities.

During the nine months ended September 30, 2011, we had no material changes outside the ordinary course of our business with respect to our debt, capital lease obligations, operating leases, purchase obligations, or other long-term liabilities; however, we made the following debt repayments:

- 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
- in February 2011, we paid $300 million to acquire the GO Zone Bonds, which were subject to mandatory tender.

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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 November 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 (stable outlook)

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

Other Commercial Commitments

As of September 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	$—
Letter of credit facility	$300	June 2012	$300
Revolving credit facility	$2,400	November 2012	$74
Canadian revolving credit facility	C$115	December 2012	C$20

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

Other Matters Impacting Liquidity and Capital Resources

Meraux Acquisition

On October 1, 2011, we acquired the Meraux Refinery and related logistics assets for an initial payment of $586 million, including inventories of $261 million, from Murphy Oil Corporation. The purchase price was funded from available cash. We expect to receive a favorable adjustment related to inventories in the fourth quarter of 2011 that will reduce the purchase price by approximately $40 million.

Contributions to Pension Plans

We have no minimum required contributions to our pension plans during 2011 under the Employee Retirement Income Security Act. However, we contributed $207 million to our pension plans in the first nine months of 2011.

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Stock Purchase Programs

As of September 30, 2011, we have approvals under common stock purchase programs to purchase approximately $3.5 billion of our common stock.

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 U.S. Environmental Protection Agency (EPA) 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. CARB has issued a variety of regulations aimed at reaching this goal, including a Low Carbon Fuel Standard (LCFS) as well as a statewide 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 statewide cap-and-trade program will begin in 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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On June 30, 2010, the EPA formally disapproved the flexible permits program submitted by the Texas Commission on Environmental Quality (TCEQ) in 1994 for inclusion in its clean-air implementation plan. The EPA determined that Texas' flexible permit program did not meet several requirements under the federal Clean Air Act. Our Port Arthur, Texas City, Three Rivers, McKee, and Corpus Christi East and West Refineries formerly operated under flexible permits administered by the TCEQ. In the fourth quarter of 2010, we completed the conversion of our flexible permits into federally enforceable conventional state NSR permits ("de-flexed permits"). We are now in the process of incorporating these de-flexed permits into our Title V permits. Continued discussions with the TCEQ and the EPA regarding this matter are likely.

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

Tax Matters

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

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.

Concentration of Customers

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.

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Sources of Liquidity

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 the accounting for our property, plant and equipment, including the manner in which we estimate the useful lives of such assets, which we have identified as a critical accounting policy.

Property, Plant and Equipment

The cost of property, plant and equipment (property assets) purchased or constructed, including betterments of property assets, are capitalized. The cost of repairs to and normal maintenance of property assets, however, is expensed as incurred. Betterments of property assets are those which either extend the useful life, increase the capacity or improve the operating efficiency of the asset, or improve the safety of our operations. The cost of property assets constructed includes interest and certain overhead costs allocable to the construction activities.

Our operations, especially those of our refining segment, are highly capital intensive. Each of our refineries is comprised of a large base of property assets, consisting of a series of interconnected, highly integrated and interdependent crude oil processing facilities and supporting logistical infrastructure (Units), and these Units are continuously improved. Improvements consist of the addition of new Units and betterments of existing Units. We plan for these improvements by developing a multi-year capital program that is updated and revised based on changing internal and external factors.

Depreciation of our property assets is recorded on a straight-line basis over the estimated useful lives of these assets primarily using the composite method of depreciation. We maintain a separate composite group of property assets for each of our 15 refineries. We estimate the useful life of each group based on an evaluation of the property assets comprising the group, and such evaluations consist of, but are not limited to, the physical inspection of the assets to determine their condition, consideration of the manner in which the assets are maintained, assessment of the need to replace assets, and evaluation of the manner in which improvements impact the useful life of the group. The estimated useful lives of our composite groups range primarily from 25 to 30 years.

Under the composite method of depreciation, the cost of an improvement is added to the composite group to which it relates and is depreciated over that group’s estimated useful life. We design improvements to our refineries in accordance with engineering specifications, design standards and practices accepted in our industry, and these improvements have design lives consistent with our estimated useful lives. Therefore, we believe the use of the group life to depreciate the cost of improvements made to the group is reasonable because the estimated useful life of each improvement is consistent with that of the group. It should be noted, however, that factors such as competition, regulation, or environmental matters could cause us to change our estimates, thus impacting depreciation expense in the future.

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Also under the composite method of depreciation, the historical cost of a minor property asset (net of salvage value) that is retired or replaced is charged to accumulated depreciation and no gain or loss is recognized in income. However, a gain or loss is recognized in income for a major property asset that is retired, replaced or sold and for an abnormal disposition of a property asset (primarily involuntary conversions). Gains and losses are reflected in depreciation and amortization expense, unless such amounts are reported separately due to materiality.

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 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 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 future results of operations and cash flows.

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	Derivative Instruments Held For Trading Purposes
September 30, 2011:		
Gain (loss) in fair value due to:		
10% increase in underlying commodity prices	$(56)	$—
10% decrease in underlying commodity prices	56	—
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 September 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 September 30, 2011 or December 31, 2010.

	September 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	$9,065
Average interest rate	— %	6.9 %	5.5 %	4.8 %	5.2 %	7.2 %	6.9 %	
Floating rate	$—	$104	$—	$—	$—	$—	$104	$104
Average interest rate	— %	0.7 %	— %	— %	— %	— %	0.7 %	

	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 and European operations that are denominated in currencies other than the local (functional) currencies of those operations. To manage our exposure to these exchange rate fluctuations, we use foreign currency exchange and purchase contracts. As of September 30, 2011, we had commitments to purchase $475 million of U.S. dollars. Our market risk was minimal on these contracts, as they matured on or before October 28, 2011, resulting in a $17 million loss in the fourth 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 September 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, or our quarterly reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011.

Litigation

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."

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.

Texas Commission on Environmental Quality (TCEQ) (McKee Refinery). In our quarterly report on Form 10-Q for the quarter ended June 30, 2011, we disclosed that our McKee Refinery had received a proposed agreed order from the TCEQ relating to alleged violations noted during an annual air compliance inspection. In the third quarter of 2011, we settled this matter with the TCEQ.

TCEQ (Three Rivers Refinery). In September 2011, our Three Rivers Refinery received a proposed agreed order that assesses a penalty of $192,663 for various alleged air violations. We believe that we have several defenses to the allegations and are working with the TCEQ to settle 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)
July 2011	9,560	$26.35	9,560	—	$3.46 billion
August 2011	10,597,275	$19.90	10,597,275	—	$3.46 billion
September 2011	2,936,270	$19.27	2,936,270	—	$3.46 billion
Total	13,543,105	$19.77	13,543,105	—	$3.46 billion

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