VALERO ENERGY CORP/TX
Form 10-K
February 27, 2014
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FORM 10-K
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
(Mark One)

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

For the fiscal year ended December 31, 2013
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	78249
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (210) 345-2000

Securities registered pursuant to Section 12(b) of the Act: Common stock, $0.01 par value per share listed on the New York Stock Exchange.
Securities registered pursuant to Section 12(g) of the Act: None.
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes R No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes R No o
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 such shorter period that the registrant was required to submit and post such files). Yes R No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]
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 Rule12b-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 aggregate market value of the voting and non-voting common stock held by non-affiliates was approximately $18.8 billion based on the last sales price quoted as of June 28, 2013 on the New York Stock Exchange, the last business day of the registrant’s most recently completed second fiscal quarter.

As of January 31, 2014, 532,510,263 shares of the registrant’s common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

We intend to file with the Securities and Exchange Commission a definitive Proxy Statement for our Annual Meeting of Stockholders scheduled for May 1, 2014, at which directors will be elected. Portions of the 2014 Proxy Statement are incorporated by reference in Part III of this Form 10-K and are deemed to be a part of this report.

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CROSS-REFERENCE SHEET

The following table indicates the headings in the 2014 Proxy Statement where certain information required in Part III of this Form 10-K may be found.

Form 10-K Item No. and Caption	Heading in 2014 Proxy Statement
10. Directors, Executive Officers and Corporate Governance	Information Regarding the Board of Directors, Independent Directors, Audit Committee, Proposal No. 1 Election of Directors, Information Concerning Nominees and Other Directors, Identification of Executive Officers, Section 16(a) Beneficial Ownership Reporting Compliance, and Governance Documents and Codes of Ethics
11. Executive Compensation	Compensation Committee, Compensation Discussion and Analysis, Director Compensation, Executive Compensation, and Certain Relationships and Related Transactions
12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	Beneficial Ownership of Valero Securities and Equity Compensation Plan Information
13. Certain Relationships and Related Transactions, and Director Independence	Certain Relationships and Related Transactions and Independent Directors
14. Principal Accountant Fees and Services	KPMG Fees for Fiscal Year 2013, KPMG Fees for Fiscal Year 2012, and Audit Committee Pre-Approval Policy

Copies of all documents incorporated by reference, other than exhibits to such documents, will be provided without charge to each person who receives a copy of this Form 10-K upon written request to Valero Energy Corporation, Attn: Secretary, P.O. Box 696000, San Antonio, Texas 78269-6000.

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PART I

The terms “Valero,” “we,” “our,” and “us,” as used in this report, may refer to Valero Energy Corporation, to one or more of our consolidated subsidiaries, or to all of them taken as a whole. In this Form 10-K, we make certain forward-looking statements, including statements regarding our plans, strategies, objectives, expectations, intentions, and resources, under the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. You should read our forward-looking statements together with our disclosures beginning on page 23 of this report under the heading: “CAUTIONARY STATEMENT FOR THE PURPOSE OF SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995.”

ITEMS 1., 1A., and 2. BUSINESS, RISK FACTORS, AND PROPERTIES

Overview. We are a Fortune 500 company based in San Antonio, Texas. Our corporate offices are at One Valero Way, San Antonio, Texas, 78249, and our telephone number is (210) 345-2000. Our common stock trades on the New York Stock Exchange (NYSE) under the symbol “VLO.” We were incorporated in Delaware in 1981 under the name Valero Refining and Marketing Company. We changed our name to Valero Energy Corporation on August 1, 1997. On January 31, 2014, we had 10,007 employees.

Our 16 petroleum refineries are located in the United States (U.S.), Canada, the United Kingdom (U.K.), and Aruba. Our refineries can produce conventional gasolines, premium gasolines, gasoline meeting the specifications of the California Air Resources Board (CARB), diesel fuel, low-sulfur diesel fuel, ultra-low-sulfur diesel fuel, CARB diesel fuel, other distillates, jet fuel, asphalt, petrochemicals, lubricants, and other refined products.

We market branded and unbranded refined products on a wholesale basis in the U.S., Canada, the Caribbean, the U.K., and Ireland through an extensive bulk and rack marketing network and through approximately 7,400 outlets that carry our brand names.

We also own 10 ethanol plants in the central plains region of the U.S. that primarily produce ethanol, which we market on a wholesale basis through a bulk marketing network.

Available Information. Our website address is www.valero.com. Information on our website is not part of this annual report on Form 10-K. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K filed with (or furnished to) the Securities and Exchange Commission (SEC) are available on our website (under “Investor Relations”) free of charge, soon after we file or furnish such material. In this same location, we also post our corporate governance guidelines, codes of ethics, and the charters of the committees of our board of directors. These documents are available in print to any stockholder that makes a written request to Valero Energy Corporation, Attn: Secretary, P.O. Box 696000, San Antonio, Texas 78269-6000.

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SEGMENTS

We have two reportable segments: refining and ethanol. Our refining segment includes refining operations, wholesale marketing, product supply and distribution, and transportation operations in the U.S., Canada, the U.K., Aruba, and Ireland. Our ethanol segment primarily includes sales of internally produced ethanol and distillers grains. Financial information about our segments is presented in Note 18 of Notes to Consolidated Financial Statements and is incorporated herein by reference.

We formerly had a third reportable segment: retail. In 2013, we completed the separation of our retail business by creating an independent public company named CST Brands, Inc. (CST). The separation of our retail business is discussed in Note 3 of Notes to Consolidated Financial Statements and that discussion is incorporated herein by reference.

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VALERO'S OPERATIONS
REFINING

On December 31, 2013, our refining operations included 16 petroleum refineries in the U.S., Canada, the U.K., and Aruba, with a combined total throughput capacity of approximately 3.1 million barrels per day (BPD). The following table presents the locations of these refineries and their approximate feedstock throughput capacities as of December 31, 2013.

Refinery	Location	Throughput Capacity [a] (BPD)
U.S. Gulf Coast:		
Corpus Christi [b]	Texas	325,000
Port Arthur	Texas	350,000
St. Charles	Louisiana	280,000
Texas City	Texas	250,000
Aruba [c]	Aruba	235,000
Houston	Texas	165,000
Meraux	Louisiana	135,000
Three Rivers	Texas	100,000
		1,840,000
U.S. Mid-Continent:		
Memphis	Tennessee	195,000
McKee	Texas	170,000
Ardmore	Oklahoma	90,000
		455,000
North Atlantic:		
Pembroke	Wales, U.K.	270,000
Quebec City	Quebec, Canada	235,000
		505,000
U.S. West Coast:		
Benicia	California	170,000
Wilmington	California	135,000
		305,000
Total		3,105,000

(a) "Throughput capacity" represents estimated capacity for processing crude oil, intermediates, and other feedstocks. Total estimated crude oil capacity is approximately 2.6 million BPD.

(b) Represents the combined capacities of two refineries – the Corpus Christi East and Corpus Christi West Refineries.

(c) The operations of the Aruba Refinery were suspended in March 2012. For further discussion of this matter, see Note 4 in Notes to Consolidated Financial Statements.

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Total Refining System

The following table presents the percentages of principal charges and yields (on a combined basis) for all of our refineries for the year ended December 31, 2013. Our total combined throughput volumes averaged 2.7 million BPD for the year ended December 31, 2013.

Combined Total Refining System Charges and Yields

Charges:			
	sour crude oil	36	%
	sweet crude oil	39	%
	residual fuel oil	10	%
	other feedstocks	4	%
	blendstocks	11	%
Yields:			
	gasolines and blendstocks	48	%
	distillates	36	%
	petrochemicals	3	%
	other products (includes petrochemicals, gas oils, No. 6 fuel oil, petroleum coke, and asphalt)	13	%

U.S. Gulf Coast

The following table presents the percentages of principal charges and yields (on a combined basis) for the nine refineries in this region for the year ended December 31, 2013. Total throughput volumes for the U.S. Gulf Coast refining region averaged 1.52 million BPD for the year ended December 31, 2013.

Combined U.S. Gulf Coast Region Charges and Yields

Charges:			
	sour crude oil	46	%
	sweet crude oil	20	%
	residual fuel oil	17	%
	other feedstocks	4	%
	blendstocks	13	%
Yields:			
	gasolines and blendstocks	45	%
	distillates	36	%
	petrochemicals	4	%
	other products (includes gas oil, No. 6 fuel oil, petroleum coke, and asphalt)	15	%

Corpus Christi East and West Refineries. Our Corpus Christi East and West Refineries are located on the Texas Gulf Coast along the Corpus Christi Ship Channel. The East Refinery processes sour crude oil into conventional gasoline, diesel, jet fuel, asphalt, aromatics, and other light products. The West Refinery specializes in processing primarily sour crude oil and residual fuel oil into premium products such as RBOB (reformulated gasoline blendstock for oxygenate blending). The East and West Refineries allow for the transfer of various feedstocks and blending components between the two refineries and the sharing of resources. The refineries typically receive and deliver feedstocks and products by tanker and barge via

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deepwater docking facilities along the Corpus Christi Ship Channel. Three truck racks with a total of 16 bays service local markets for gasoline, diesel, jet fuels, liquefied petroleum gases, and asphalt. Finished products are distributed across the refineries' docks into ships or barges, and are transported via third-party pipelines to the Colonial, Explorer, Valley, and other major pipelines.

Port Arthur Refinery. Our Port Arthur Refinery is located on the Texas Gulf Coast approximately 90 miles east of Houston. The refinery processes primarily heavy sour crude oils and other feedstocks into gasoline, diesel, jet fuel, petrochemicals, intermediates, petroleum coke, and sulfur. The refinery's newest major unit is a 60,000 BPD hydrocracker (completed in 2012), constructed to expand the refinery's yield of distillates. The refinery receives crude oil over marine docks and through crude oil pipelines, and has access to the Sunoco and Oiltanking terminals at Nederland, Texas. Finished products are distributed into the Colonial, Explorer, and TEPPCO pipelines and across the refinery docks into ships or barges.

St. Charles Refinery. Our St. Charles Refinery is located approximately 15 miles west of New Orleans along the Mississippi River. The refinery processes sour crude oils and other feedstocks into gasoline, distillates, and other light products. In 2013, we completed construction and placed into operation a 60,000 BPD hydrocracker at this refinery. The refinery receives crude oil over five marine docks and has access to the Louisiana Offshore Oil Port where it can receive crude oil through a 24-inch pipeline. Finished products can be shipped over these docks or through the Colonial pipeline network for distribution to the eastern U.S.

Texas City Refinery. Our Texas City Refinery is located southeast of Houston on the Texas City Ship Channel. The refinery processes crude oils into a wide slate of products. The refinery receives its feedstocks by the Cameron Highway, Houston Offshore Oil, and Seaway Enterprise pipelines, and by ship and barge via deepwater docking facilities along the Texas City Ship Channel. The refinery uses ships and barges, as well as the Colonial, Explorer and TEPPCO pipelines for distribution of its products.

Houston Refinery. Our Houston Refinery is located on the Houston Ship Channel. It processes a mix of crude oils and intermediate oils into reformulated gasoline and distillates. The refinery receives its feedstocks via interstate crude pipelines, tankers at deepwater docking facilities along the Houston Ship Channel and interconnecting pipelines with the Texas City Refinery. It delivers its products through major pipelines, including the Colonial, Explorer, Orion, and TEPPCO pipelines.

Meraux Refinery. Our Meraux Refinery is located in St. Bernard Parish southeast of New Orleans. The refinery processes primarily medium sour crude oils into gasoline, distillates, and other light products. The refinery receives crude oil at its marine dock and has access to the Louisiana Offshore Oil Port where it can receive crude oil via the Clovelly-Alliance-Meraux pipeline system. Finished products can be shipped from the refinery's dock or through the Colonial pipeline network for distribution to the eastern U.S. The Meraux Refinery is located about 40 miles from our St. Charles Refinery, allowing for integration of feedstocks and refined product blending.

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Three Rivers Refinery. Our Three Rivers Refinery is located in South Texas between Corpus Christi and San Antonio. It processes sweet and medium sour crude oils into gasoline, distillates, and aromatics. Additionally, the refinery has recently installed processing equipment to facilitate the processing of lighter domestic crude oil. The refinery has access to crude oil from sources outside the U.S. delivered to the Texas Gulf Coast at Corpus Christi as well as crude oil from U.S. sources through third-party pipelines and trucks. A 70-mile pipeline transports crude oil via connections to the Three Rivers Refinery from Corpus Christi. To capitalize on the increase in the production of domestic crude oil in South Texas, the refinery has installed facilities to receive increased volumes of domestic crude oil by truck and new third-party pipelines. The refinery distributes its refined products primarily through third-party pipelines.

Aruba Refinery. Our Aruba Refinery is located on the island of Aruba in the Caribbean Sea. The refinery heretofore processed primarily heavy sour crude oil and produced intermediate feedstocks and finished distillate products. The refinery receives crude oil by ship at its two deepwater marine docks, which can berth ultra-large crude carriers. The operations of the Aruba Refinery were suspended in March 2012, and in September 2012, we reorganized the refinery into a crude oil and refined products terminal. For additional information about this matter, see Note 4 of Notes to Consolidated Financial Statements.

U.S. Mid-Continent

The following table presents the percentages of principal charges and yields (on a combined basis) for the three refineries in this region for the year ended December 31, 2013. Total throughput volumes for the U.S. Mid-Continent refining region averaged approximately 435,000 BPD for the year ended December 31, 2013.

Combined U.S. Mid-Continent Region Charges and Yields

Charges:			
	sour crude oil	8	%
	sweet crude oil	83	%
	other feedstocks	1	%
	blendstocks	8	%
Yields:			
	gasolines and blendstocks	55	%
	distillates	35	%
	petrochemicals	5	%
	other products (includes gas oil, No. 6 fuel oil, and asphalt)	5	%

Memphis Refinery. Our Memphis Refinery is located in Tennessee along the Mississippi River’s Lake McKellar. It processes primarily sweet crude oils. Most of its production is light products, including regular and premium gasoline, diesel, jet fuels, and petrochemicals. Crude oil is supplied to the refinery via the Capline pipeline and can also be received, along with other feedstocks, via barge. The refinery’s products are distributed via truck racks, barges, and a pipeline network, including one pipeline directly to the Memphis airport.

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McKee Refinery. Our McKee Refinery is located in the Texas Panhandle. It processes primarily sweet crude oils into conventional gasoline, RBOB, low-sulfur diesel, jet fuels, and asphalt. The refinery has access to crude oil from Texas, Oklahoma, Kansas, and Colorado through third-party pipelines. The refinery also has access at Wichita Falls, Texas to third-party pipelines that transport crude oil from West Texas to the U.S. Mid-Continent region. The refinery distributes its products primarily via third-party pipelines to markets in Texas, New Mexico, Arizona, Colorado, and Oklahoma.

Ardmore Refinery. Our Ardmore Refinery is located in Ardmore, Oklahoma, approximately 100 miles south of Oklahoma City. It processes medium sour and sweet crude oils into conventional gasoline, ultra-low-sulfur diesel, liquefied petroleum gas products, and asphalt. Local crude oil is gathered by Enterprise’s crude oil gathering/trunkline systems and trucking operations, and is then transported to the refinery through third-party crude oil pipelines. The refinery also receives crude oil from other locations via third-party pipelines. Refined products are transported to market via railcars, trucks, and the Magellan pipeline system.

North Atlantic

The following table presents the percentages of principal charges and yields (on a combined basis) for the two refineries in this region for the year ended December 31, 2013. Total throughput volumes for the North Atlantic refining region averaged approximately 459,000 BPD for the year ended December 31, 2013.

Combined North Atlantic Region Charges and Yields

Charges:			
	sour crude oil	6	%
	sweet crude oil	80	%
	residual fuel oil	6	%
	other feedstocks	1	%
	blendstocks	7	%
Yields:			
	gasolines and blendstocks	43	%
	distillates	44	%
	petrochemicals	1	%
	other products (includes gas oil, No. 6 fuel oil, and other products)	12	%

Pembroke Refinery. Our Pembroke Refinery is located in the County of Pembrokeshire in southwest Wales, U.K. The refinery processes primarily sweet crude oils into ultra-low sulfur gasoline and diesel, jet fuel, heating oil, and low sulfur fuel oil. The refinery receives all of its feedstocks and delivers the majority of its products by ship and barge via deepwater docking facilities along the Milford Haven Waterway with its remaining products being delivered by our Mainline pipeline system and by tanker trucks.

Quebec City Refinery. Our Quebec City Refinery is located in Lévis, Canada (near Quebec City). It processes sweet, high mercaptan crude oils and lower-quality, sweet acidic crude oils, western Canadian synthetic oil, West Texas Intermediate (WTI) crude oil and shale oil into conventional gasoline, low-sulfur diesel, jet fuel, heating oil, and propane. The refinery receives crude oil by ship at its deepwater dock on the St. Lawrence River and by rail cars. The refinery transports its products through our pipeline from Quebec City to our terminal in Montreal and to various other terminals throughout eastern Canada by trains, ships, trucks and third-party pipelines.

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U.S. West Coast

The following table presents the percentages of principal charges and yields (on a combined basis) for the two refineries in this region for the year ended December 31, 2013. Total throughput volumes for the U.S. West Coast refining region averaged approximately 265,000 BPD for the year ended December 31, 2013.

Combined U.S. West Coast Region Charges and Yields

Charges:			
	sour crude oil	70	%
	sweet crude oil	4	%
	other feedstocks	11	%
	blendstocks	15	%
Yields:			
	gasolines and blendstocks	59	%
	distillates	27	%
	other products (includes gas oil, No. 6 fuel oil, petroleum coke, and asphalt)	14	%

Benicia Refinery. Our Benicia Refinery is located northeast of San Francisco on the Carquinez Straits of San Francisco Bay. It processes sour crude oils into premium products, primarily CARBOB gasoline, a reformulated gasoline mixture that meets the specifications of the California Air Resources Board (CARB) when blended with ethanol. The refinery receives crude oil feedstocks via a marine dock that can berth large crude oil carriers and a 20-inch crude oil pipeline connected to a southern California crude oil delivery system. Most of the refinery's products are distributed via the Kinder Morgan pipeline system in California.

Wilmington Refinery. Our Wilmington Refinery is located near Los Angeles, California. The refinery processes a blend of lower-cost heavy and high-sulfur crude oils. The refinery can produce all of its gasoline as CARBOB gasoline and produces ultra-low-sulfur diesel, CARB diesel, and jet fuel. The refinery is connected by pipeline to marine terminals and associated dock facilities that can move and store crude oil and other feedstocks. Refined products are distributed via the Kinder Morgan pipeline system and various third-party terminals in southern California, Nevada, and Arizona.

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Feedstock Supply

Approximately 51 percent of our current crude oil feedstock requirements are purchased through term contracts while the remaining requirements are generally purchased on the spot market. Our term supply agreements include arrangements to purchase feedstocks at market-related prices directly or indirectly from various national oil companies as well as international and U.S. oil companies. The contracts generally permit the parties to amend the contracts (or terminate them), effective as of the next scheduled renewal date, by giving the other party proper notice within a prescribed period of time (e.g., 60 days, 6 months) before expiration of the current term. The majority of the crude oil purchased under our term contracts is purchased at the producer's official stated price (i.e., the "market" price established by the seller for all purchasers) and not at a negotiated price specific to us.

Refining Segment Sales

Overview

Our refining segment includes sales of refined products in both the wholesale rack and bulk markets. These sales include refined products that are manufactured in our refining operations as well as refined products purchased or received on exchange from third parties. Most of our refineries have access to marine transportation facilities and interconnect with common-carrier pipeline systems, allowing us to sell products in the U.S., Canada, the U.K., and other countries. No customer accounted for more than 10 percent of our total operating revenues in 2013.

Wholesale Marketing

We market branded and unbranded refined products on a wholesale basis through an extensive rack marketing network. The principal purchasers of our refined products from terminal truck racks are wholesalers, distributors, retailers, and truck-delivered end users throughout the U.S., Canada, the U.K., and Ireland.

The majority of our rack volume is sold through unbranded channels. The remainder is sold to distributors and dealers that are members of the Valero-brand family that operate approximately 5,600 branded sites in the U.S., approximately 1,000 branded sites in the U.K. and Ireland, and approximately 800 branded sites in Canada. These sites are independently owned and are supplied by us under multi-year contracts. For wholesale branded sites, we promote the Valero®, Beacon®, and Shamrock® brands in the U.S., the Ultramar® brand in Canada, and the Texaco® brand in the U.K. and Ireland.

Bulk Sales and Trading

We sell a significant portion of our gasoline and distillate production through bulk sales channels in U.S. and international markets. Our bulk sales are made to various oil companies and traders as well as certain bulk end-users such as railroads, airlines, and utilities. Our bulk sales are transported primarily by pipeline, barges, and tankers to major tank farms and trading hubs.

We also enter into refined product exchange and purchase agreements. These agreements help minimize transportation costs, optimize refinery utilization, balance refined product availability, broaden geographic distribution, and provide access to markets not connected to our refined-product pipeline systems. Exchange agreements provide for the delivery of refined products by us to unaffiliated companies at our and third-parties' terminals in exchange for delivery of a similar amount of refined products to us by these unaffiliated companies at specified locations. Purchase agreements involve our purchase of refined products from third parties with delivery occurring at specified locations.

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Specialty Products

We sell a variety of other products produced at our refineries, which we refer to collectively as “Specialty Products.” Our Specialty Products include asphalt, lube oils, natural gas liquids (NGLs), petroleum coke, petrochemicals, and sulfur.

- We produce asphalt at five of our refineries. Our asphalt products are sold for use in road construction, road repair, and roofing applications through a network of refinery and terminal loading racks.
- We produce naphthenic oils at one of our refineries suitable for a wide variety of lubricant and process applications.
- NGLs produced at our refineries include butane, isobutane, and propane. These products can be used for gasoline blending, home heating, and petrochemical plant feedstocks.
- We are a significant producer of petroleum coke, supplying primarily power generation customers and cement manufacturers. Petroleum coke is used largely as a substitute for coal.
- We produce and market a number of commodity petrochemicals including aromatics (benzene, toluene, and xylene) and two grades of propylene. Aromatics and propylenes are sold to customers in the chemical industry for further processing into such products as paints, plastics, and adhesives.
- We are a large producer of sulfur with sales primarily to customers serving the agricultural sector. Sulfur is used in manufacturing fertilizer.

Logistics and Transportation

We own several transportation and logistics assets (crude oil pipelines, refined product pipelines, terminals, tanks, marine docks, truck rack bays, railcars, and rail facilities) that support our refining and ethanol operations. In addition, through subsidiaries, we own 100 percent of the general partner interest of Valero Energy Partners LP and approximately 70 percent of its limited partner interests. Valero Energy Partners LP is a midstream master limited partnership. Its common units representing limited partner interests are traded on the NYSE under the symbol “VLP.” Its assets support the operations of our Port Arthur, McKee, and Memphis Refineries. Valero Energy Partners LP is discussed more fully in Note 5 of Notes to Consolidated Financial Statements.

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ETHANOL

We own 10 ethanol plants with a combined ethanol production capacity of about 1.2 billion gallons per year. Our ethanol plants are dry mill facilities[1] that process corn to produce ethanol and distillers grains.[2] We source our corn supply from local farmers and commercial elevators. Our facilities receive corn primarily by rail and truck. We publish on our website a corn bid for local farmers and cooperative dealers to use to facilitate corn supply transactions.

After processing, our ethanol is held in storage tanks on-site pending loading to trucks and railcars. We sell our ethanol (i) to large customers – primarily refiners and gasoline blenders – under term and spot contracts, and (ii) in bulk markets such as New York, Chicago, the U.S. Gulf Coast, Florida, and the U.S. West Coast. We ship our dry distillers grains (DDG) by truck or rail primarily to animal feed customers in the U.S. and Mexico, with some sales into the Far East. We also sell modified distillers grains locally at our plant sites.

The following table presents the locations of our ethanol plants, their approximate ethanol and DDG production capacities, and their approximate corn processing capacities.

State	City	Ethanol Production Capacity (in gallons per year)	Production of DDG (in tons per year)	Corn Processed (in bushels per year)
Indiana	Linden	120 million	355,000	42 million
Iowa	Albert City	120 million	355,000	42 million
	Charles City	125 million	370,000	44 million
	Fort Dodge	125 million	370,000	44 million
	Hartley	125 million	370,000	44 million
Minnesota	Welcome	125 million	370,000	44 million
Nebraska	Albion	120 million	355,000	42 million
Ohio	Bloomingburg	120 million	355,000	42 million
South Dakota	Aurora	125 million	370,000	44 million
Wisconsin	Jefferson	100 million	320,000	37 million
	total	1,205 million	3,590,000	425 million

The combined production of denatured ethanol from our plants in 2013 averaged 3.3 million gallons per day.

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1 Ethanol is commercially produced using either the wet mill or dry mill process. Wet milling involves separating the grain kernel into its component parts (germ, fiber, protein, and starch) prior to fermentation. In the dry mill process, the entire grain kernel is ground into flour. The starch in the flour is converted to ethanol during the fermentation process, creating carbon dioxide and distillers grains.

2 During fermentation, nearly all of the starch in the grain is converted into ethanol and carbon dioxide, while the remaining nutrients (proteins, fats, minerals, and vitamins) are concentrated to yield modified distillers grains, or, after further drying, dried distillers grains. Distillers grains generally are an economical partial replacement for corn, soybean, and dicalcium phosphate in feeds for livestock, swine, and poultry.

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RISK FACTORS

Risk Factors Related to Our Business

Our financial results are affected by volatile refining margins, which are dependent upon factors beyond our control.
Our financial results are primarily affected by the relationship, or margin, between refined product prices and the prices for crude oil and other feedstocks. Our cost to acquire feedstocks and the price at which we can ultimately sell refined products depend upon several factors beyond our control, including regional and global supply of and demand for crude oil, gasoline, diesel, and other feedstocks and refined products. These in turn depend on, among other things, the availability and quantity of imports, the production levels of U.S. and international suppliers, levels of refined product inventories, productivity and growth (or the lack thereof) of U.S. and global economies, U.S. relationships with foreign governments, political affairs, and the extent of governmental regulation. Historically, refining margins have been volatile, and we believe they will continue to be volatile in the future.

Economic turmoil and political unrest or hostilities, including the threat of future terrorist attacks, could affect the economies of the U.S. and other countries. Lower levels of economic activity could result in declines in energy consumption, including declines in the demand for and consumption of our refined products, which could cause our revenues and margins to decline and limit our future growth prospects.

Refining margins are also significantly impacted by additional refinery conversion capacity through the expansion of existing refineries or the construction of new refineries. Worldwide refining capacity expansions may result in refining production capability exceeding refined product demand, which would have an adverse effect on refining margins.

A significant portion of our profitability is derived from the ability to purchase and process crude oil feedstocks that historically have been cheaper than benchmark crude oils, such as Louisiana Light Sweet (LLS) and Brent crude oils. These crude oil feedstock differentials vary significantly depending on overall economic conditions and trends and conditions within the markets for crude oil and refined products, and they could decline in the future, which would have a negative impact on our results of operations.

Uncertainty and illiquidity in credit and capital markets can impair our ability to obtain credit and financing on acceptable terms, and can adversely affect the financial strength of our business partners.
Our ability to obtain credit and capital depends in large measure on capital markets and liquidity factors that we do not control. Our ability to access credit and capital markets may be restricted at a time when we would like, or need, to access those markets, which could have an impact on our flexibility to react to changing economic and business conditions. In addition, the cost and availability of debt and equity financing may be adversely impacted by unstable or illiquid market conditions. Protracted uncertainty and illiquidity in these markets also could have an adverse impact on our lenders, commodity hedging counterparties, or our customers, causing them to fail to meet their obligations to us. In addition, decreased returns on pension fund assets may also materially increase our pension funding requirements.

Our access to credit and capital markets also depends on the credit ratings assigned to our debt by independent credit rating agencies. We currently maintain investment-grade ratings by Standard & Poor’s Ratings Services (S&P), Moody’s Investors Service (Moody’s), and Fitch Ratings (Fitch) on our senior unsecured debt. Ratings from credit agencies are not recommendations to buy, sell, or hold our securities. Each rating should be evaluated independently of any other rating. We cannot provide assurance that any of our current ratings

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will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Specifically, if ratings agencies were to downgrade our long-term rating, particularly below investment grade, our borrowing costs would increase, which could adversely affect our ability to attract potential investors and our funding sources could decrease. In addition, we may not be able to obtain favorable credit terms from our suppliers or they may require us to provide collateral, letters of credit, or other forms of security, which would increase our operating costs. As a result, a downgrade below investment grade in our credit ratings could have a material adverse impact on our financial position, results of operations, and liquidity.

From time to time, our cash needs may exceed our internally generated cash flow, and our business could be materially and adversely affected if we were unable to obtain necessary funds from financing activities. From time to time, we may need to supplement our cash generated from operations with proceeds from financing activities. We have existing revolving credit facilities, committed letter of credit facilities, and an accounts receivable sales facility to provide us with available financing to meet our ongoing cash needs. In addition, we rely on the counterparties to our derivative instruments to fund their obligations under such arrangements. Uncertainty and illiquidity in financial markets may materially impact the ability of the participating financial institutions and other counterparties to fund their commitments to us under our various financing facilities or our derivative instruments, which could have a material adverse effect on our financial position, results of operations, and liquidity.

Compliance with and changes in environmental laws, including proposed climate change laws and regulations, could adversely affect our performance.
The principal environmental risks associated with our operations are emissions into the air and releases into the soil, surface water, or groundwater. Our operations are subject to extensive 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 gasoline and diesel fuels. Certain of these laws and regulations could impose obligations to conduct assessment or remediation efforts at our facilities as well as at formerly owned properties or third-party sites where we have taken wastes for disposal or where our wastes have migrated. Environmental laws and regulations also may impose liability on us for the conduct of third parties, or for actions that complied with applicable requirements when taken, regardless of negligence or fault. If we violate or fail to comply with these laws and regulations, we could be fined or otherwise sanctioned.

Because environmental laws and regulations are becoming more stringent and new environmental laws and regulations are continuously being enacted or proposed, such as those relating to greenhouse gas emissions and climate change, the level of expenditures required for environmental matters could increase in the future. Current and future legislative action and regulatory initiatives could result in changes to operating permits, material changes in operations, increased capital expenditures and operating costs, increased costs of the goods we sell, and decreased demand for our products that cannot be assessed with certainty at this time. We may be required to make expenditures to modify operations or install pollution control equipment that could materially and adversely affect our business, financial condition, results of operations, and liquidity. For example, in 2012, the U.S. Environmental Protection Agency (EPA) proposed more stringent requirements for refinery air emissions through revisions to existing New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants. The EPA also issued final amendments to Subpart Ja of the New Source Performance Standards, which included revisions to certain emission limits, monitoring requirements, fuel gas concentration limits, and waste gas flow limits for process heaters and flares. In addition, the EPA has, in recent years, adopted final rules making more stringent the National Ambient Air Quality Standards (NAAQS) for ozone, sulfur dioxide and nitrogen dioxide, and the EPA is

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considering further revisions to the NAAQS. Emerging rules and permitting requirements implementing these revised standards may require us to install more stringent controls at our facilities, which may result in increased capital expenditures. Governmental restrictions on greenhouse gas emissions – including so-called “cap-and-trade” programs targeted at reducing carbon dioxide emissions – could result in material increased compliance costs, additional operating restrictions or permitting delays for our business, and an increase in the cost of, and reduction in demand for, the products we produce, which could have a material adverse effect on our financial position, results of operations, and liquidity.

Disruption of our ability to obtain crude oil could adversely affect our operations.
A significant portion of our feedstock requirements is satisfied through supplies originating in the Middle East, Africa, Asia, North America, and South America. We are, therefore, subject to the political, geographic, and economic risks attendant to doing business with suppliers located in, and supplies originating from, these areas. If one or more of our supply contracts were terminated, or if political events disrupt our traditional crude oil supply, we believe that adequate alternative supplies of crude oil would be available, but it is possible that we would be unable to find alternative sources of supply. If we are unable to obtain adequate crude oil volumes or are able to obtain such volumes only at unfavorable prices, our results of operations could be materially adversely affected, including reduced sales volumes of refined products or reduced margins as a result of higher crude oil costs.

In addition, the U.S. government can prevent or restrict us from doing business in or with other countries. These restrictions, and those of other governments, could limit our ability to gain access to business opportunities in various countries. Actions by both the U.S. and other countries have affected our operations in the past and will continue to do so in the future.

We are subject to interruptions of supply and increased costs as a result of our reliance on third-party transportation of crude oil and refined products.
We often use the services of third parties to transport feedstocks and refined products to and from our facilities. If we experience prolonged interruptions of supply or increases in costs to deliver refined products to market, or if the ability of the pipelines or vessels to transport feedstocks or refined products is disrupted because of weather events, accidents, governmental regulations, or third-party actions, it could have a material adverse effect on our financial position, results of operations, and liquidity.

Competitors that produce their own supply of feedstocks, own their own retail sites, have greater financial resources, or provide alternative energy sources may have a competitive advantage.
The refining and marketing industry is highly competitive with respect to both feedstock supply and refined product markets. We compete with many companies for available supplies of crude oil and other feedstocks and for sites for our refined products. We do not produce any of our crude oil feedstocks and, following the separation of our retail business, we do not have a company-owned retail network. Many of our competitors, however, obtain a significant portion of their feedstocks from company-owned production and some have extensive retail sites. Such competitors are at times able to offset losses from refining operations with profits from producing or retailing operations, and may be better positioned to withstand periods of depressed refining margins or feedstock shortages.

Some of our competitors also have materially greater financial and other resources than we have. Such competitors have a greater ability to bear the economic risks inherent in all phases of our industry. In addition,

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we compete with other industries that provide alternative means to satisfy the energy and fuel requirements of our industrial, commercial, and individual consumers.

A significant interruption in one or more of our refineries or our information technology systems could adversely affect our business.

Our refineries are our principal operating assets. As a result, our operations could be subject to significant interruption if one or more of our refineries were to experience a major accident or mechanical failure, encounter work stoppages relating to organized labor issues, be damaged by severe weather or other natural or man-made disaster, such as an act of terrorism, or otherwise be forced to shut down. If any refinery were to experience an interruption in operations, earnings from the refinery could be materially adversely affected (to the extent not recoverable through insurance) because of lost production and repair costs. Significant interruptions in our refining system could also lead to increased volatility in prices for crude oil feedstocks and refined products, and could increase instability in the financial and insurance markets, making it more difficult for us to access capital and to obtain insurance coverage that we consider adequate.

In addition, our information technology systems and network infrastructure may be subject to unauthorized access or attack, which could result in a loss of sensitive business information, systems interruption, or the disruption of our business operations. There can be no assurance that our infrastructure protection technologies and disaster recovery plans can prevent a technology systems breach or systems failure, which could have a material adverse effect on our financial position or results of operations.

We are subject to operational risks and our insurance may not be sufficient to cover all potential losses arising from operating hazards. Failure by one or more insurers to honor its coverage commitments for an insured event could materially and adversely affect our financial position, results of operations, and liquidity.

Our refining and marketing operations are subject to various hazards common to the industry, including explosions, fires, toxic emissions, maritime hazards, and natural catastrophes. As protection against these hazards, we maintain insurance coverage against some, but not all, potential losses and liabilities. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies could increase substantially. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, coverage for hurricane damage is very limited, and coverage for terrorism risks includes very broad exclusions. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results of operations, and liquidity.

Our insurance program includes a number of insurance carriers. Significant disruptions in financial markets could lead to a deterioration in the financial condition of many financial institutions, including insurance companies. We can make no assurances that we will be able to obtain the full amount of our insurance coverage for insured events.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax liabilities imposed by multiple jurisdictions, including income taxes, indirect taxes (excise/duty, sales/use, gross receipts, and value-added taxes), payroll taxes, franchise taxes, withholding taxes, 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

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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.

We may incur losses as a result of our forward-contract activities and derivative transactions.
We currently use commodity derivative instruments, and we expect to continue their use in the future. If the instruments we use to hedge our exposure to various types of risk are not effective, we may incur losses.

One of our subsidiaries acts as the general partner of a publicly traded master limited partnership, Valero Energy Partners LP, which may involve a greater exposure to legal liability than our historic business operations.

One of our subsidiaries acts as the general partner of Valero Energy Partners LP, a publicly traded master limited partnership. Our control of the general partner of Valero Energy Partners LP may increase the possibility of claims of breach of fiduciary duties, including claims of conflicts of interest, related to Valero Energy Partners LP. Liability resulting from such claims could have a material adverse effect on our financial position, results of operations, and liquidity.

If our spin-off of CST Brands, Inc. (the "Spin-off"), or certain internal transactions undertaken in anticipation of the Spin-off, were determined to be taxable for U.S. federal income tax purposes, then we and our stockholders could be subject to significant tax liability.

We have received a private letter ruling from the Internal Revenue Service (IRS) substantially to the effect that, for U.S. federal income tax purposes, the Spin-off, except for cash received in lieu of fractional shares, will qualify as tax-free under sections 355 and 361 of the U.S. Internal Revenue Code of 1986, as amended (Code), and that certain internal transactions undertaken in anticipation of the Spin-off qualified for favorable treatment. The IRS did not rule, however, on whether the Spin-off satisfied certain requirements necessary to obtain tax-free treatment under section 355 of the Code. Instead, the private letter ruling was based on representations by us that those requirements were satisfied, and any inaccuracy in those representations could invalidate the private letter ruling. In connection with the private letter ruling, we also obtained an opinion from a nationally recognized accounting firm, substantially to the effect that, for U.S. federal income tax purposes, the Spin-off qualified under sections 355 and 361 of the Code. The opinion relied on, among other things, the continuing validity of the private letter ruling and various assumptions and representations as to factual matters made by CST and us which, if inaccurate or incomplete in any material respect, would jeopardize the conclusions reached by such counsel in its opinion. The opinion is not binding on the IRS or the courts, and there can be no assurance that the IRS or the courts would not challenge the conclusions stated in the opinion or that any such challenge would not prevail. Furthermore, notwithstanding the private letter ruling, the IRS could determine on audit that the Spin-off or the internal transactions undertaken in anticipation of the Spin-off should be treated as taxable transactions if it determines that any of the facts, assumptions, representations, or undertakings we or CST have made or provided to the IRS is incorrect or incomplete, or that the Spin-off or the internal transactions should be taxable for other reasons, including as a result of a significant change in stock or asset ownership after the Spin-off.

If the Spin-off ultimately were determined to be taxable, each holder of our common stock who received shares of CST common stock in the Spin-off generally would be treated as receiving a Spin-off of property in an amount equal to the fair market value of the shares of CST common stock received by such holder. Any such Spin-off would be a dividend to the extent of our current earnings and profits as of the end of 2013,

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and any accumulated earnings and profits. Any amount that exceeded our relevant earnings and profits would be treated first as a non-taxable return of capital to the extent of such holder's tax basis in our shares of common stock with any remaining amount generally being taxed as a capital gain. In addition, we would recognize gain in an amount equal to the excess of the fair market value of shares of CST common stock distributed to our holders on the Spin-off date over our tax basis in such shares of CST common stock. Moreover, we could incur significant U.S. federal income tax liabilities if it ultimately were determined that certain internal transactions undertaken in anticipation of the Spin-off were taxable.

Under the terms of the tax matters agreement we entered into with CST in connection with the Spin-off, we generally are responsible for any taxes imposed on us and our subsidiaries in the event that the Spin-off and/or certain related internal transactions were to fail to qualify for tax-free treatment. However, if the Spin-off and/or such internal transactions were to fail to qualify for tax-free treatment because of actions or failures to act by CST or its subsidiaries, CST would be responsible for all such taxes. If we were to become liable for taxes under the tax matters agreement, that liability could have a material adverse effect on us. The Spin-off is more fully described in Note 3 of Notes to Consolidated Financial Statements.

ENVIRONMENTAL MATTERS

We incorporate by reference into this Item the environmental disclosures contained in the following sections of this report:

- Item 1 under the caption "Risk Factors – Compliance with and changes in environmental laws, including proposed climate change laws and regulations, could adversely affect our performance,"
- Item 3, "Legal Proceedings" under the caption "Environmental Enforcement Matters," and
- Item 8, "Financial Statements and Supplementary Data" in Note 10 of Notes to Consolidated Financial Statements under the caption "Environmental Liabilities," and Note 12 of Notes to Consolidated Financial Statements under the caption "Environmental Matters."

Capital Expenditures Attributable to Compliance with Environmental Regulations. In 2013, our capital expenditures attributable to compliance with environmental regulations were $69 million, and are currently estimated to be $90 million for 2014 and $204 million for 2015. The estimates for 2014 and 2015 do not include amounts related to capital investments at our facilities that management has deemed to be strategic investments. These amounts could materially change as a result of governmental and regulatory actions.

PROPERTIES

Our principal properties are described above under the caption "Valero's Operations," and that information is incorporated herein by reference. We believe that our properties and facilities are generally adequate for our operations and that our facilities are maintained in a good state of repair. As of December 31, 2013, we were the lessee under a number of cancelable and noncancelable leases for certain properties. Our leases are discussed more fully in Notes 11 and 12 of Notes to Consolidated Financial Statements. Financial information about our properties is presented in Note 8 of Notes to Consolidated Financial Statements and is incorporated herein by reference.

Our patents relating to our refining operations are not material to us as a whole. The trademarks and tradenames under which we conduct our branded wholesale business – including Valero®, Diamond Shamrock®, Shamrock®, Ultramar®, Beacon®, Texaco® – and other trademarks employed in the marketing of petroleum products are integral to our wholesale marketing operations.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Litigation

We incorporate by reference into this Item our disclosures made in Part II, Item 8 of this report included in Note 12 of 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, results of operations, or liquidity. 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.

EPA (St. Charles Refinery). In our quarterly report on Form 10-Q for the quarter ended June 30, 2013, we reported that the EPA had issued to our St. Charles Refinery a draft Compliance Agreement and Final Order assessing a penalty of $440,000 for various alleged violations under the Clean Air Act’s Section 112(r) and the EPA’s Risk Management Program. Recently, we resolved the matter with the EPA.

People of the State of Illinois, ex rel. v. The Premcor Refining Group Inc., et al., Third Judicial Circuit Court, Madison County (Case No. 03-CH-00459, filed May 29, 2003) (Hartford Refinery and terminal). The Illinois Environmental Protection Agency has issued several Notices of Violation (NOVs) alleging violations of air and waste regulations at Premcor’s Hartford, Illinois terminal and closed refinery. We are negotiating the terms of a consent order for corrective action.

Bay Area Air Quality Management District (BAAQMD) (Benicia Refinery). We currently have multiple outstanding Violation Notices (VNs) issued by the BAAQMD in 2011, 2012, and 2013, which we reasonably believe may result in penalties of $100,000 or more. These VNs are for various alleged air regulation and air permit violations at our Benicia Refinery and asphalt plant. We continue to work with the BAAQMD to resolve these VNs.

South Coast Air Quality Management District (SCAQMD) (Wilmington Refinery). We currently have multiple NOVs issued by the SCAQMD, which we reasonably believe may result in penalties of $100,000 or more. These NOVs are for alleged reporting violations and excess emissions at our Wilmington Refinery. We continue to work with the SCAQMD to resolve these NOVs.

Texas Commission on Environmental Quality (TCEQ) (Port Arthur Refinery). In our annual report on Form 10-K for the year ended December 31, 2012, we reported that our Port Arthur Refinery received a proposed agreed order from the TCEQ that assessed a penalty of $180,911 for various alleged air emission and reporting violations. The Port Arthur Refinery has also received additional Notices of Enforcement (NOEs), for which we have not received proposed penalty amounts but reasonably believe may result in penalties of $100,000 or more. We are working with the TCEQ to resolve all of these outstanding violations.

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TCEQ (Port Arthur Refinery). In our annual report on Form 10-K for the year ended December 31, 2012, we reported that the TCEQ issued an NOE for unauthorized flare emissions. Potential stipulated penalties under our EPA §114 Clean Air Act Consent Decree for these incidents are expected to be $166,000 should the EPA issue a stipulated penalty demand letter for these events.

ITEM 4. MINE SAFETY DISCLOSURES

None.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock trades on the NYSE under the symbol “VLO.”

As of January 31, 2014, there were 6,628 holders of record of our common stock.

The following table shows the high and low sales prices of and dividends declared on our common stock for each quarter of 2013 and 2012.

	Sales Prices of the Common Stock		Dividends Per Common Share
Quarter Ended	High	Low	
2013:			
December 31	$50.40	$33.73	$0.225
September 30	37.13	33.54	0.225
June 30	44.97	33.76	0.200
March 31	48.51	34.35	0.200
2012:			
December 31	34.38	28.20	0.175
September 30	33.75	23.64	0.175
June 30	26.33	20.37	0.150
March 31	28.56	19.61	0.150

On January 22, 2014, our board of directors declared a quarterly cash dividend of $0.25 per common share payable March 12, 2014 to holders of record at the close of business on February 12, 2014.

Dividends are considered quarterly by the board of directors and may be paid only when approved by the board.

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The following table discloses purchases of shares of Valero’s common stock made by us or on our behalf during the fourth quarter of 2013.

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)
October 2013	2,692,850	$34.10	85,708	2,607,142	$ 2.9 billion
November 2013	2,413,232	$41.76	343,227	2,070,005	$ 2.8 billion
December 2013	3,172,462	$46.37	1,134	3,171,328	$ 2.6 billion
Total	8,278,544	$41.04	430,069	7,848,475	$ 2.6 billion

(a) The shares reported in this column represent purchases settled in the fourth quarter of 2013 relating to (i) our purchases of shares in open-market transactions to meet our obligations under stock-based compensation plans, and (ii) 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 stock-based 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. During 2013, we completed the $6 billion program. On February 28, 2008, we announced that our board of directors approved a $3 billion common stock purchase program, which was in addition to the $6 billion program. This $3 billion program has no expiration date.

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The following performance graph is not “soliciting material,” is not deemed filed with the SEC, and is not to be incorporated by reference into any of Valero’s filings under the Securities Act of 1933 or the Securities Exchange Act of 1934, as amended, respectively.

This performance graph and the related textual information are based on historical data and are not indicative of future performance. The following line graph compares the cumulative total return[1] on an investment in our common stock against the cumulative total return of the S&P 500 Composite Index and an index of peer companies (that we selected) for the five-year period commencing December 31, 2008 and ending December 31, 2013. Our peer group comprises the following 11 companies: Alon USA Energy, Inc.; BP plc; CVR Energy, Inc.; Delek US Holdings, Inc. (DK); HollyFrontier Corporation; Marathon Petroleum Corporation; PBF Energy Inc. (PBF); Phillips 66; Royal Dutch Shell plc; Tesoro Corporation; and Western Refining, Inc. Our peer group previously included Hess Corporation, but it has exited the refining business, and was replaced in our peer group by DK and PBF who are also engaged in refining operations.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN[1]
Among Valero Energy Corporation, the S&P 500 Index,
Old Peer Group, and New Peer Group

	12/2008	12/2009	12/2010	12/2011	12/2012	12/2013
Valero Common Stock	$100.00	$79.77	$111.31	$102.57	$170.45	$281.24
S&P 500	100.00	126.46	145.51	148.59	172.37	228.19
Old Peer Group	100.00	126.98	122.17	127.90	138.09	170.45
New Peer Group	100.00	127.95	120.42	129.69	136.92	166.57

1 Assumes that an investment in Valero common stock and each index was $100 on December 31, 2008. “Cumulative total return” is based on share price appreciation plus reinvestment of dividends from December 31, 2008 through December 31, 2013.

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ITEM 6. SELECTED FINANCIAL DATA

The selected financial data for the five-year period ended December 31, 2013 was derived from our audited financial statements. The following table should be read together with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with the historical financial statements and accompanying notes included in Item 8, "Financial Statements and Supplementary Data."

The following summaries are in millions of dollars, except for per share amounts:

	Year Ended December 31,				
	2013 (a)	2012 (b)	2011 (c)	2010 (d)	2009 (d)
Operating revenues	$138,074	$139,250	$125,987	$82,233	$64,599
Income (loss) from continuing operations	2,728	2,080	2,096	923	(273)
Earnings per common share from continuing operations – assuming dilution	4.97	3.75	3.69	1.62	(0.50)
Dividends per common share	0.85	0.65	0.30	0.20	0.60
Total assets	47,260	44,477	42,783	37,621	35,572
Debt and capital lease obligations, less current portion	6,261	6,463	6,732	7,515	7,163

(a) Includes the operations of our retail business prior to its separation from us on May 1, 2013, as further described in Note 3 of Notes to Consolidated Financial Statements.

(b) The operations of the Aruba Refinery were suspended in March 2012, as further described in Note 4 of Notes to Consolidated Financial Statements.

(c) We acquired the Meraux Refinery on October 1, 2011 and the Pembroke Refinery on August 1, 2011. The information presented for 2011 includes the results of operations from these acquisitions commencing on their respective acquisition dates.

(d) We acquired three ethanol plants in the first quarter of 2010 and seven ethanol plants in the second quarter of 2009. The information presented for 2010 and 2009 includes the results of operations of these plants commencing on their respective acquisition dates.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following review of our results of operations and financial condition should be read in conjunction with Items 1, 1A, and 2, “Business, Risk Factors, and Properties,” and Item 8, “Financial Statements and Supplementary Data,” included in this report.

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

This report, including without limitation our disclosures 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,” “goal,” “guidance,” “ “should,” “may,” and similar expressions.

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

- future refining margins, including gasoline and distillate 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 these capital investments on our results of operations;
- anticipated trends in the supply of and demand for crude oil and other feedstocks and refined products globally and in the regions where we operate;
- expectations regarding environmental, tax, and other regulatory initiatives; and
- the effect of general economic and other conditions on refining, 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;
- demand for, and supplies of, refined products such as gasoline, diesel fuel, jet fuel, petrochemicals, and ethanol;
- demand for, and supplies of, crude oil and other feedstocks;

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- the ability of the members of the Organization of Petroleum Exporting Countries 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;
- the actions taken by competitors, including both pricing and adjustments to refining capacity in response to market conditions;
- the level of competitors' imports into markets that we supply;
- accidents, unscheduled shutdowns, or other catastrophes affecting our refineries, machinery, pipelines, equipment, and information systems, 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;
- 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 legislation or rulemakings by governmental authorities, 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;
- overall economic conditions, including the stability and liquidity of financial markets; and
- other factors generally described in the "Risk Factors" section included in Items 1, 1A, and 2, "Business, Risk Factors, and Properties" in this report.

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

Overview

For the year ended December 31, 2013, we reported net income attributable to Valero stockholders of $2.7 billion, or $4.97 per share (assuming dilution), compared to $2.1 billion, or $3.75 per share (assuming dilution), for the year ended December 31, 2012.

The increase in net income attributable to Valero stockholders of $637 million was primarily due to the effect of asset impairment losses of $1.0 billion recorded during the year ended December 31, 2012, which lowered net income for 2012, as compared to the year ended December 31, 2013. In addition, during 2013, we recorded a $325 million nontaxable gain related to the disposition of our retained interest in CST Brands, Inc. (CST), which is more fully described in Notes 3 and 11 of Notes to Consolidated Financial Statements. Excluding these significant items, net income attributable to Valero stockholders for 2013 declined by $702 million due primarily to lower refining segment operating income as discussed below.

Our operating income decreased $47 million from 2012 to 2013 as outlined by business segment in the following table (in millions):

	Year Ended December 31,		
	2013	2012	Change
Operating income (loss) by business segment:			
Refining	$4,217	$4,450	$(233)
Retail	81	348	(267)
Ethanol	491	(47)	538
Corporate	(826)	(741)	(85)
Total	$3,963	$4,010	$(47)

Operating income for 2012 was negatively impacted by asset impairment losses of $1.0 billion, of which $928 million related to our Aruba refinery (as further discussed in Note 4 of Notes to Consolidated Financial Statements), and severance expense of $41 million, which was also related to our Aruba Refinery (as further discussed in Note 10 of Notes to Consolidated Financial Statements). Excluding these significant items, total operating income and refining segment operating income for 2012 would have been $5.1 billion and $5.5 billion, respectively, resulting in a $1.1 billion decrease in total operating income and a $1.3 billion decrease in refining segment operating income from 2012 to 2013.

The $1.3 billion decrease in refining segment operating income for 2013 compared to 2012 was primarily due to lower refining margins in each of our regions. The decrease in refining margins was the result of lower gasoline margins, lower discounts on light sweet crude oils, and higher costs of biofuel credits (primarily Renewable Identification Numbers (RINs) needed to comply with the U.S. federal Renewable Fuel Standard (RFS)), which were partially offset by higher distillate margins and higher discounts on sour crude oils between the years.

On May 1, 2013, we completed the separation of our retail business by spinning off 80 percent of CST as an independent public company. As a result, we no longer operate a retail business and had no retail segment operating results after April 30, 2013, resulting in the $267 million decrease in retail segment operating income for 2013 compared to 2012. The separation of our retail business is more fully discussed in Note 3 of Notes to Consolidated Financial Statements.

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Our ethanol segment operating income in 2013 increased $538 million compared to 2012 due to higher gross margin per gallon of ethanol and higher production volumes. Lower corn prices and higher ethanol prices contributed to the improved gross margin. We increased our production of ethanol following the first quarter of 2013 to capture the improved economics of higher gross margins per gallon during 2013.

On December 16, 2013, Valero Energy Partners LP (VLP) completed its initial public offering of 17,250,000 common units at a price of $23.00 per unit, which included a 2,250,000 common unit over-allotment option that was fully exercised by the underwriters. VLP received $369 million in net proceeds from the sale of the units, after deducting underwriting fees, structuring fees and other offering costs. VLP's initial assets include crude oil and refined petroleum products pipeline and terminal systems in the U.S. Gulf Coast and U.S. Mid-Continent regions that are integral to the operations of our Port Arthur, McKee, and Memphis Refineries. See Note 5 of Notes to Consolidated Financial Statements for additional information.

Outlook

Our refining segment benefits from processing sour crude oils (such as Maya crude oil) in our U.S. Gulf Coast region and light sweet crude oils (such as WTI crude oil) in our U.S. Mid-Continent region due to the favorable discounts between the prices of these types of crude oil and the price of Brent crude oil. Because the market for refined products generally tracks the price of Brent crude oil, which is a benchmark sweet crude oil, we benefit when we process crude oils that are priced at a discount to Brent crude oil. The discounts in the prices of light sweet and sour crude oils compared to the price of Brent crude oil widened significantly during the fourth quarter of 2013. For the first quarter of 2014, discounts on light sweet and sour crude oils narrowed slightly compared to the fourth quarter and we expect these discounts to remain volatile for the remainder of the first quarter.

In addition, gasoline margins across all regions were seasonally weak during the fourth quarter of 2013 and remain seasonally weak thus far in the first quarter of 2014. Distillate margins across all regions, thus far in 2014, have remained consistent with those realized during the fourth quarter of 2013. We are exposed to the volatility in the market prices of crude oil and refined products, and we expect such prices to continue to be volatile in the near to mid-term.

We are also exposed to the volatility in the market price of biofuel credits (primarily RINs in the U.S.), which we purchase in the open market to meet our obligation to blend biofuels into the products we produce. To date during the first quarter of 2014, the market price of RINs has increased compared to year end levels, but the price remains lower than prices experienced during 2013. Therefore, we estimate that the cost of meeting our obligation for the full year of 2014 will be between $250 million and $350 million. Because the market price of RINs is volatile and is significantly impacted by biofuel blending rates that are established by the EPA, it is difficult for us to predict reliably the market price of RINs.

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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.
2013 Compared to 2012
Financial Highlights
(millions of dollars, except per share amounts)

	Year Ended December 31,		
	2013 (a)	2012	Change
Operating revenues	$138,074	$139,250	$(1,176)
Costs and expenses:			
Cost of sales	127,316	127,268	48
Operating expenses:			
Refining (b)	3,704	3,668	36
Retail	226	686	(460)
Ethanol	387	332	55
General and administrative expenses	758	698	60
Depreciation and amortization expense:			
Refining	1,566	1,370	196
Retail	41	119	(78)
Ethanol	45	42	3
Corporate	68	43	25
Asset impairment losses (c)	—	1,014	(1,014)
Total costs and expenses	134,111	135,240	(1,129)
Operating income	3,963	4,010	(47)
Gain on disposition of retained interest in CST Brands, Inc. (a)	325	—	325
Other income, net	59	9	50
Interest and debt expense, net of capitalized interest	(365)	(313)	(52)
Income before income tax expense	3,982	3,706	276
Income tax expense	1,254	1,626	(372)
Net income	2,728	2,080	648
Less: Net income (loss) attributable to noncontrolling interests	8	(3)	11
Net income attributable to Valero stockholders	$2,720	$2,083	$637
Earnings per common share – assuming dilution	$4.97	$3.75	$1.22

See note references on page 32.

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

	Year Ended December 31,		
	2013	2012	Change
Refining (b) (c):			
Operating income	$4,217	$4,450	$(233)
Throughput margin per barrel (e)	$9.69	$10.96	$(1.27)
Operating costs per barrel:			
Operating expenses	3.78	3.79	(0.01)
Depreciation and amortization expense	1.60	1.44	0.16
Total operating costs per barrel	5.38	5.23	0.15
Operating income per barrel	$4.31	$5.73	$(1.42)
Throughput volumes (thousand BPD):			
Feedstocks:			
Heavy sour crude	486	453	33
Medium/light sour crude	466	547	(81)
Sweet crude	1,039	991	48
Residuals	282	200	82
Other feedstocks	106	120	(14)
Total feedstocks	2,379	2,311	68
Blendstocks and other	303	302	1
Total throughput volumes	2,682	2,613	69
Yields (thousand BPD):			
Gasolines and blendstocks	1,287	1,251	36
Distillates	984	918	66
Other products (f)	440	467	(27)
Total yields	2,711	2,636	75

See note references on page 32.

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

	Year Ended December 31,		
	2013	2012	Change
U.S. Gulf Coast (b) (c):			
Operating income	$2,381	$2,541	$(160)
Throughput volumes (thousand BPD)	1,523	1,488	35
Throughput margin per barrel (e)	$9.57	$9.65	$(0.08)
Operating costs per barrel:			
Operating expenses	3.66	3.55	0.11
Depreciation and amortization expense	1.63	1.44	0.19
Total operating costs per barrel	5.29	4.99	0.30
Operating income per barrel	$4.28	$4.66	$(0.38)
U.S. Mid-Continent:			
Operating income	$1,293	$2,044	$(751)
Throughput volumes (thousand BPD)	435	430	5
Throughput margin per barrel (e)	$13.37	$18.49	$(5.12)
Operating costs per barrel:			
Operating expenses	3.58	4.02	(0.44)
Depreciation and amortization expense	1.64	1.48	0.16
Total operating costs per barrel	5.22	5.50	(0.28)
Operating income per barrel	$8.15	$12.99	$(4.84)
North Atlantic:			
Operating income	$570	$752	$(182)
Throughput volumes (thousand BPD)	459	428	31
Throughput margin per barrel (e)	$7.93	$9.24	$(1.31)
Operating costs per barrel:			
Operating expenses	3.50	3.59	(0.09)
Depreciation and amortization expense	1.03	0.85	0.18
Total operating costs per barrel	4.53	4.44	0.09
Operating income per barrel	$3.40	$4.80	$(1.40)
U.S. West Coast:			
Operating income (loss)	$(27)	$147	$(174)
Throughput volumes (thousand BPD)	265	267	(2)
Throughput margin per barrel (e)	$7.43	$8.84	$(1.41)
Operating costs per barrel:			
Operating expenses	5.35	5.09	0.26
Depreciation and amortization expense	2.35	2.25	0.10
Total operating costs per barrel	7.70	7.34	0.36
Operating income (loss) per barrel	$(0.27)	$1.50	$(1.77)
Operating income for regions above	$4,217	$5,484	$(1,267)
Severance expense (b)	—	(41)	41
Asset impairment losses (c)	—	(993)	993
Total refining operating income	$4,217	$4,450	$(233)

See note references on page 32.

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

	Year Ended December 31, 2013	2012	Change
Feedstocks:			
Brent crude oil	$108.74	$111.70	(2.96)
Brent less West Texas Intermediate (WTI) crude oil	10.80	17.55	(6.75)
Brent less Alaska North Slope (ANS) crude oil	1.00	1.08	(0.08)
Brent less Louisiana Light Sweet (LLS) crude oil	0.41	(0.91)	1.32
Brent less Mars crude oil	5.52	3.97	1.55
Brent less Maya crude oil	11.31	12.06	(0.75)
LLS crude oil	108.33	112.61	(4.28)
LLS less Mars crude oil	5.11	4.88	0.23
LLS less Maya crude oil	10.90	12.97	(2.07)
WTI crude oil	97.94	94.15	3.79
Natural gas (dollars per million British thermal units)	3.69	2.71	0.98
Products:			
U.S. Gulf Coast:			
CBOB gasoline less Brent	2.69	4.89	(2.20)
Ultra-low-sulfur diesel less Brent	15.95	16.48	(0.53)
Propylene less Brent	(2.72)	(22.38)	19.66
CBOB gasoline less LLS	3.10	3.98	(0.88)
Ultra-low-sulfur diesel less LLS	16.36	15.57	0.79
Propylene less LLS	(2.31)	(23.29)	20.98
U.S. Mid-Continent:			
CBOB gasoline less WTI (d)	16.77	25.40	(8.63)
Ultra-low-sulfur diesel less WTI	28.33	34.96	(6.63)
North Atlantic:			
CBOB gasoline less Brent	8.50	10.66	(2.16)
Ultra-low-sulfur diesel less Brent	17.84	19.06	(1.22)
U.S. West Coast:			
CARBOB 87 gasoline less ANS	12.69	15.39	(2.70)
CARB diesel less ANS	18.83	19.93	(1.10)
CARBOB 87 gasoline less WTI	22.49	31.86	(9.37)
CARB diesel less WTI	28.63	36.40	(7.77)
New York Harbor corn crush (dollars per gallon)	0.42	(0.15)	0.57

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See note references on page 32.

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

	Year Ended December 31,		
	2013	2012	Change
Retail:			
Operating income (a) (c)	$81	$348	$(267)
Ethanol:			
Operating income (loss)	$491	$(47)	$538
Ethanol production (thousand gallons per day)	3,294	2,967	327
Gross margin per gallon of production (e)	$0.77	$0.30	$0.47
Operating costs per gallon of production:			
Operating expenses	0.32	0.30	0.02
Depreciation and amortization expense	0.04	0.04	—
Total operating costs per gallon of production	0.36	0.34	0.02
Operating income (loss) per gallon of production	$0.41	$(0.04)	$0.45

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See note references on page 32.

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The following notes relate to references on pages 27 through 31.

(a) On May 1, 2013, we completed the separation of our retail business by spinning off 80 percent of CST. This transaction is more fully discussed in Note 3 of Notes to Consolidated Financial Statements. As a result and effective May 1, 2013, our results of operations no longer include those of CST, except for our share of CST's results of operations associated with the equity interest in CST retained by us through November 14, 2013, which is reflected in "other income, net" for the year ended December 31, 2013. The nature and significance of our post-separation participation in the supply of motor fuel to CST represents a continuation of activities with CST for accounting purposes. As such, the historical results of operations related to CST have not been reported as discontinued operations in the statements of income. In October 2013, we borrowed $525 million under a short-term debt agreement with a third-party financial institution in anticipation of liquidating our retained interest in CST. This liquidation was completed on November 14, 2013 by transferring all remaining shares of CST common stock owned by us to the financial institution in exchange for $467 million of our short-term debt, and we paid the remaining $58 million of short-term debt in cash. After paying $19 million of fees, we recognized a $325 million nontaxable gain.

(b) In September 2012, we decided to reorganize our Aruba Refinery into a crude oil and refined products terminal. The reorganization resulted in the termination of the majority of our employees in Aruba, and we recognized severance expense of $41 million in September 2012. This expense is reflected in refining segment operating income for the year ended December 31, 2012, but it is excluded from operating costs per barrel for the refining segment and the U.S. Gulf Coast region. No income tax benefits were recognized related to this severance expense.

(c) Asset impairment losses for the year ended December 31, 2012 include a $928 million loss on the write-down of the Aruba Refinery. In addition, we recorded asset impairment losses of $65 million ($42 million after taxes) related to equipment associated with permanently cancelled capital projects at several of our refineries and $21 million ($13 million after taxes) related to certain retail stores in 2012 that we owned prior to the separation of our retail business. The total asset impairment losses of $1.0 billion are reflected in the operating income of the respective segments for the year ended December 31, 2012, but the asset impairment losses associated with the Aruba Refinery and the cancelled capital projects are excluded from the operating costs per barrel and operating income per barrel for the refining segment and the U.S. Gulf Coast region.

(d) U.S. Mid-Continent product specifications for gasoline changed on September 16, 2013 from Conventional 87 gasoline to CBOB gasoline. Therefore, average market reference prices for comparable products meeting the new specifications required in this region are now being provided for all periods presented.

(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, sulfur, and asphalt.

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

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General

Operating revenues decreased $1.2 billion (or 1 percent) for the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily as a result of lower average refined product prices between the two years related to our refining segment operations. In addition, operating income decreased $47 million for the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to a $233 million decrease in refining segment operating income, a $267 million decrease in retail segment operating income, and a $60 million increase in general and administrative expenses, partially offset by a $538 million increase in ethanol segment operating income. The reasons for these changes in the operating results of our segments and general and administrative expenses, as well as other items that affected our income, are discussed below.

Refining

Refining segment operating income decreased $233 million from $4.5 billion for the year ended December 31, 2012 to $4.2 billion for the year ended December 31, 2013. Excluding asset impairment losses and severance expenses of $993 million and $41 million in 2012 primarily related to our Aruba Refinery, which are more fully described in Notes 4 and 10 of Notes to Consolidated Financial Statements, respectively, refining segment operating income decreased $1.3 billion from 2012 to 2013. The decrease in refining segment operating income was primarily due to a $994 million decrease in refining margin, a $196 million increase in depreciation and amortization expense, and a $36 million increase in operating expenses.

Refining margin decreased $994 million (a $1.27 per barrel decrease) in 2013 compared to 2012, primarily due to the following:

- Decrease in gasoline margins - We experienced a decline in gasoline margins throughout all of our regions during 2013 compared to 2012. For example, the WTI-based benchmark reference margin for U.S. Mid-Continent CBOB gasoline was $16.77 per barrel during 2013 compared to $25.40 per barrel during 2012, representing an unfavorable decrease of $8.63 per barrel. We estimate that the decline in gasoline margins per barrel during 2013 compared to 2012 had a negative impact to our refining margin of approximately $790 million for all refining regions.

- Lower discounts on WTI-type crude oils in the U.S. Mid-Continent region - Because the market for refined products generally tracks the price of Brent crude oil, which is a benchmark sweet crude oil, we benefit when we process crude oils that are priced at a discount to Brent crude oil. In 2013, the discount in the price of WTI compared to the price of Brent crude oil narrowed compared to 2012. WTI crude oil sold at a discount of $10.80 per barrel to Brent crude oil in 2013 compared to a discount of $17.55 per barrel in 2012, representing an unfavorable decrease of $6.75 per barrel. Therefore, the lower discount on WTI-type crude oils that we processed negatively impacted our refining margin. We estimate that the decrease in the discounts for WTI-type crude oils that we processed during 2013 reduced our refining margin by approximately $640 million.

- Higher costs of biofuel credits - As more fully described in Note 21 of Notes to Consolidated Financial Statements, we must purchase biofuel credits in order to meet our biofuel blending obligation under various government and regulatory compliance programs, and the cost of these credits (primarily RINs in the U.S.) increased by $267 million from $250 million in 2012 to $517 million in 2013. This increase was due to an increase in the market price of RINs caused by an expectation in the market of a shortage in available RINs.

- Increase in distillate margins - Despite lower distillate prices throughout all of our regions during 2013 compared to 2012, we experienced an increase in distillate margins during 2013 compared to 2012 as a

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result of increased production volumes of distillate between the years. This production volume increase of 66,000 barrels per day was primarily due to the start up of our new hydrocracker units at our Port Arthur and St. Charles Refineries, resulting in a $370 million increase in our refining margin in 2013.

- Higher discounts on medium sour crude oils - In 2013, the discount in the price of medium sour crude oils compared to the price of Brent crude oil widened. For example, Mars crude oil, which is a medium sour crude oil, sold at a discount of $5.52 per barrel to Brent crude oil in 2013 compared to a discount of $3.97 per barrel during 2012, representing a favorable increase of $1.55 per barrel.Therefore, the higher discounts on the medium sour crude oils we processed favorably impacted our refining margin. We estimate that the increase in the discounts for medium sour crude oils that we processed during 2013 had a favorable impact to our refining margin of approximately $260 million.

The increase of $36 million in operating expenses was primarily due to a $185 million increase in energy costs related to higher natural gas costs and higher use of natural gas associated with our new hydrocracker units at our Port Arthur and St. Charles Refineries. This increase was partially offset by a $124 million decrease in operating expenses incurred by the Aruba Refinery, whose operations were suspended in March 2012.

The increase of $196 million in depreciation and amortization expense was due to additional depreciation expense primarily associated with our new hydrocracker units at our Port Arthur and St. Charles Refineries that began operating in late 2012 and the third quarter of 2013, respectively, and an increase in refinery turnaround and catalyst amortization.

Retail

Retail segment operating income was $81 million for the year ended December 31, 2013 compared to $348 million for the year December 31, 2012. The $267 million decrease was primarily due to the separation of our retail business on May 1, 2013, which is more fully described in Note 3 of Notes to Consolidated Financial Statements. As a result of the separation, retail segment operating income for 2013 reflects the operations of our former retail business for only the first four months of 2013.

Ethanol

Ethanol segment operating income was $491 million for the year ended December 31, 2013 compared to an operating loss of $47 million for the year ended December 31, 2012. The $538 million increase in operating income was primarily due to a $596 million increase in gross margin, partially offset by a $55 million increase in operating expenses.

Ethanol gross margin per gallon increased $0.47 per gallon from $0.30 per gallon in 2012 to $0.77 per gallon in 2013 due to the following:

- Lower corn prices - Corn prices decreased year over year as many of the corn-producing regions of the U.S. Mid-Continent recovered from a drought that began in the second quarter of 2012. For example, the Chicago Board of Trade corn price was $5.80 per bushel in 2013 compared to $6.94 per bushel in 2012. The decrease in the price of corn that we processed during 2013 favorably impacted our ethanol margin by approximately $290 million.

- Higher ethanol prices - Ethanol prices increased year over year due to a decrease in the supply of ethanol in the market. The decrease in supply resulted from reduced production in 2012 and early 2013 as the industry responded to a narrowing of ethanol gross margin per gallon, which were due to higher corn prices primarily caused by the drought in the corn-producing regions of the U.S. Mid-

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Continent described above. By mid-2013, ethanol inventory levels in the U.S. had declined to their lowest level in over three years and as a result, prices increased significantly beginning late in the first quarter of 2013. For example, the New York Harbor ethanol price was $2.53 per gallon in 2013 compared to $2.37 per gallon in 2012. The increase in the price of ethanol per gallon during 2013 had a favorable impact to our ethanol margin of approximately $160 million.

- Increased production volumes - Ethanol margin also improved due to increased production volumes between the years of 327,000 gallons per day in 2013 compared to 2012 in response to the improved ethanol gross margin per gallon. The increase in production volumes during 2013 had a favorable impact to our ethanol gross margin of approximately $85 million.

The $55 million increase in operating expenses during 2013 compared to 2012 was primarily due to a $40 million increase in energy costs compared to 2012 resulting from higher natural gas prices during 2013 and a $12 million year over year increase in chemical costs due to higher production.

Corporate Expenses and Other

General and administrative expenses increased $60 million from the year ended December 31, 2012 to the year ended December 31, 2013 primarily due to $52 million of environmental and legal reserve adjustments that were recorded during 2013 and $30 million for transaction costs related to the separation of our retail business on May 1, 2013. These increases were partially offset by an $11 million reduction in insurance reserves during 2013. The increase in corporate depreciation and amortization expense was primarily due to $20 million of losses incurred on the sale of certain corporate property.

During the year ended December 31, 2013, we recognized a nontaxable gain of $325 million, or $0.60 per share, related to the disposition of our retained interest in CST, which is more fully described in Note 11 of Notes to Consolidated Financial Statements.

“Interest and debt expense, net of capitalized interest” for year ended December 31, 2013 increased $52 million from the year ended December 31, 2012. This increase was primarily due to a $103 million decrease in capitalized interest due to completion of several large capital projects, including the new hydrocrackers at our Port Arthur and St. Charles Refineries, offset by a $44 million favorable impact from the decrease in average borrowings and a $12 million write-off of unamortized debt discounts related to the early redemption of certain industrial revenue bonds in the first quarter of 2012.

Income tax expense decreased $372 million from the year ended December 31, 2012 to the year ended December 31, 2013. The variation in the customary relationship between income tax expense and income from continuing operations before income tax expense for the year ended December 31, 2013 was primarily due to the nontaxable gain on the disposition of our retained interest in CST. The variation in the customary relationship between income tax expense and income before income tax expense for 2012 was primarily due to not recognizing the tax benefits associated with the asset impairment loss of $928 million and the severance expense of $41 million related to the Aruba Refinery as we did not expect to realize a tax benefit from these losses.

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2012 Compared to 2011

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

	Year Ended December 31,		
	2012	2011	Change
Operating revenues	$139,250	$125,987	$13,263
Costs and expenses:			
Cost of sales (c)	127,268	115,719	11,549
Operating expenses:			
Refining (d)	3,668	3,406	262
Retail	686	678	8
Ethanol	332	399	(67)
General and administrative expenses	698	571	127
Depreciation and amortization expense:			
Refining	1,370	1,338	32
Retail	119	115	4
Ethanol	42	39	3
Corporate	43	42	1
Asset impairment loss (e)	1,014	—	1,014
Total costs and expenses	135,240	122,307	12,933
Operating income	4,010	3,680	330
Other income, net	9	43	(34)
Interest and debt expense, net of capitalized interest	(313)	(401)	88
Income from continuing operations before income tax expense	3,706	3,322	384
Income tax expense	1,626	1,226	400
Income from continuing operations	2,080	2,096	(16)
Loss from discontinued operations, net of income taxes	—	(7)	7
Net income	2,080	2,089	(9)
Less: Net loss attributable to noncontrolling interest	(3)	(1)	(2)
Net income attributable to Valero stockholders	$2,083	$2,090	$(7)
Net income attributable to Valero stockholders:			
Continuing operations	$2,083	$2,097	$(14)
Discontinued operations	—	(7)	7
Total	$2,083	$2,090	$(7)
Earnings per common share – assuming dilution:			
Continuing operations	$3.75	$3.69	$0.06
Discontinued operations	—	(0.01)	0.01
Total	$3.75	$3.68	$0.07

See note references on page 41.

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

	Year Ended December 31,		
	2012	2011	Change
Refining (a) (b):			
Operating income (c) (d) (e)	$4,450	$3,516	$934
Throughput margin per barrel (c) (f)	$10.96	$9.91	$1.05
Operating costs per barrel:			
Operating expenses (d)	3.79	3.83	(0.04)
Depreciation and amortization expense	1.44	1.51	(0.07)
Total operating costs per barrel (e)	5.23	5.34	(0.11)
Operating income per barrel	$5.73	$4.57	$1.16
Throughput volumes (thousand BPD):			
Feedstocks:			
Heavy sour crude	453	454	(1)
Medium/light sour crude	547	442	105
Sweet crude	991	861	130
Residuals	200	282	(82)
Other feedstocks	120	122	(2)
Total feedstocks	2,311	2,161	150
Blendstocks and other	302	273	29
Total throughput volumes	2,613	2,434	179
Yields (thousand BPD):			
Gasolines and blendstocks	1,251	1,120	131
Distillates	918	834	84
Other products (g)	467	494	(27)
Total yields	2,636	2,448	188

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See note references on page 41.

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

	Year Ended December 31, 2012	2011	Change
U.S. Gulf Coast (a):			
Operating income (c) (d) (e)	$2,541	$2,205	$336
Throughput volumes (thousand BPD)	1,488	1,450	38
Throughput margin per barrel (c) (f)	$9.65	$9.33	$0.32
Operating costs per barrel:			
Operating expenses (d)	3.55	3.66	(0.11)
Depreciation and amortization expense	1.44	1.50	(0.06)
Total operating costs per barrel (d) (e)	4.99	5.16	(0.17)
Operating income per barrel	$4.66	$4.17	$0.49
U.S. Mid-Continent:			
Operating income (c)	$2,044	$1,535	$509
Throughput volumes (thousand BPD)	430	411	19
Throughput margin per barrel (c) (f)	$18.49	$15.91	$2.58
Operating costs per barrel:			
Operating expenses	4.02	4.15	(0.13)
Depreciation and amortization expense	1.48	1.52	(0.04)
Total operating costs per barrel	5.50	5.67	(0.17)
Operating income per barrel	$12.99	$10.24	$2.75
North Atlantic (b):			
Operating income	$752	$171	$581
Throughput volumes (thousand BPD)	428	317	111
Throughput margin per barrel (f)	$9.24	$5.43	$3.81
Operating costs per barrel:			
Operating expenses	3.59	3.08	0.51
Depreciation and amortization expense	0.85	0.87	(0.02)
Total operating costs per barrel	4.44	3.95	0.49
Operating income per barrel	$4.80	$1.48	$3.32
U.S. West Coast:			
Operating income (c)	$147	$147	$—
Throughput volumes (thousand BPD)	267	256	11
Throughput margin per barrel (c) (f)	$8.84	$9.11	$(0.27)
Operating costs per barrel:			
Operating expenses	5.09	5.25	(0.16)
Depreciation and amortization expense	2.25	2.29	(0.04)
Total operating costs per barrel	7.34	7.54	(0.20)
Operating income per barrel	$1.50	$1.57	$(0.07)
Operating income for regions above	$5,484	$4,058	$1,426
Loss on derivative contracts related to the forward sales of refined product (c)	—	(542)	542
Severance expense (d)	(41)	—	(41)
Asset impairment loss applicable to refining (e)	(993)	—	(993)

Total refining operating income	$4,450	$3,516	$934

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See note references on page 41.

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

	Year Ended December 31,		
	2012	2011	Change
Feedstocks:			
Brent crude oil	$111.70	$110.93	$0.77
Brent less WTI crude oil	17.55	15.88	1.67
Brent less ANS crude oil	1.08	1.39	(0.31)
Brent less LLS crude oil	(0.91)	(0.54)	(0.37)
Brent less Mars crude oil	3.97	3.46	0.51
Brent less Maya crude oil	12.06	12.18	(0.12)
LLS crude oil	112.61	111.47	1.14
LLS less Mars crude oil	4.88	4.00	0.88
LLS less Maya crude oil	12.97	12.72	0.25
WTI crude oil	94.15	95.05	(0.90)
Natural gas (dollars per million British thermal units)	2.71	3.96	(1.25)
Products:			
U.S. Gulf Coast:			
CBOB gasoline less Brent	4.89	5.17	(0.28)
Ultra-low-sulfur diesel less Brent	16.48	13.78	2.70
Propylene less Brent	(22.38)	8.23	(30.61)
CBOB gasoline less LLS	3.98	4.63	(0.65)
Ultra-low-sulfur diesel less LLS	15.57	13.24	2.33
Propylene less LLS	(23.29)	7.69	(30.98)
U.S. Mid-Continent:			
CBOB gasoline less WTI (i)	25.40	22.37	3.03
Ultra-low-sulfur diesel less WTI	34.96	31.06	3.90
North Atlantic:			
CBOB gasoline less Brent	10.66	5.95	4.71
Ultra-low-sulfur diesel less Brent	19.06	15.64	3.42
U.S. West Coast:			
CARBOB 87 gasoline less ANS	15.39	11.48	3.91
CARB diesel less ANS	19.93	18.47	1.46
CARBOB 87 gasoline less WTI	31.86	25.97	5.89
CARB diesel less WTI	36.40	32.96	3.44
New York Harbor corn crush (dollars per gallon)	(0.15)	0.25	(0.40)

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See note references on page 41.

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

	Year Ended December 31, 2012	2011	Change
Retail–U.S.:			
Operating income (e)	$240	$213	$27
Company-operated fuel sites (average)	1,013	994	19
Fuel volumes (gallons per day per site)	5,083	5,060	23
Fuel margin per gallon	$0.162	$0.144	$0.018
Merchandise sales	$1,239	$1,223	$16
Merchandise margin (percentage of sales)	29.7%	28.7%	1.0%
Margin on miscellaneous sales	$89	$88	$1
Operating expenses	$434	$416	$18
Depreciation and amortization expense	$77	$77	$—
Asset impairment loss (e)	$12	$—	$12
Retail–Canada:			
Operating income (e)	$108	$168	$(60)
Fuel volumes (thousand gallons per day)	3,096	3,195	(99)
Fuel margin per gallon	$0.258	$0.299	$(0.041)
Merchandise sales	$257	$261	$(4)
Merchandise margin (percentage of sales)	29.0%	29.4%	(0.4)%
Margin on miscellaneous sales	$44	$43	$1
Operating expenses	$252	$262	$(10)
Depreciation and amortization expense	$42	$38	$4
Asset impairment loss (e)	$9	$—	$9
Ethanol:			
Operating income (loss)	$(47)	$396	$(443)
Ethanol production (thousand gallons per day)	2,967	3,352	(385)
Gross margin per gallon of production (f)	$0.30	$0.68	$(0.38)
Operating costs per gallon of production:			
Operating expenses	0.30	0.33	(0.03)
Depreciation and amortization expense	0.04	0.03	0.01
Total operating costs per gallon of production	0.34	0.36	(0.02)
Operating income (loss) per gallon of production	$(0.04)	$0.32	$(0.36)

See note references on page 41.

The following notes relate to references on pages 36 through 40.

(a) The financial highlights and operating highlights for the refining segment and U.S. Gulf Coast region reflect the results of operations of our Meraux Refinery, including related logistics assets, from the date of its acquisition on October 1, 2011.

(b) The financial highlights and operating highlights for the refining segment and North Atlantic region reflect the results of operations of our Pembroke Refinery, including the related market and logistics business, from the date of its acquisition on August 1, 2011.

(c) Cost of sales for the year ended December 31, 2011 includes a loss of $542 million ($352 million after taxes) on commodity derivative contracts related to the forward sales of refined product. These contracts were closed and realized during the first quarter of 2011. This loss is reflected in refining segment operating income for the year ended December 31, 2011, but throughput margin per barrel for the refining segment excludes this $542 million loss ($0.61 per barrel). In addition, operating income and throughput margin per barrel for the U.S. Gulf Coast, the U.S. Mid-Continent, and the U.S. West Coast regions for the year ended December 31, 2011 exclude the portion of this loss that had been allocated to them of $372 million ($0.70 per barrel), $122 million ($0.81 per barrel), and $48 million ($0.51 per barrel), respectively.

(d) In September 2012, we decided to reorganize our Aruba Refinery into a crude oil and refined products terminal. The reorganization resulted in the termination of the majority of our employees in Aruba, and we recognized severance expense of $41 million in September 2012. This expense is reflected in refining segment operating income for the year ended December 31, 2012, but it is excluded from operating costs per barrel for the refining segment and the U.S. Gulf Coast region. No income tax benefits were recognized related to this severance expense.

(e) Asset impairment losses for the year ended December 31, 2012 include a $928 million loss on the write-down of the Aruba Refinery. In addition, we recorded asset impairment losses of $65 million ($42 million after taxes) related to equipment associated with a permanently cancelled capital project at another refinery and $21 million ($13 million after taxes) related to certain retail stores in 2012. The total asset impairment losses of $1.0 billion are reflected in the operating income of the respective segments for the year ended December 31, 2012, but the asset impairment losses associated with the Aruba Refinery and the cancelled capital projects are excluded from the operating costs per barrel and operating income per barrel for the refining segment and the U.S. Gulf Coast region.

(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 U.S. Gulf Coast region includes Aruba, Corpus Christi East, Corpus Christi West, Houston, Meraux, Port Arthur, St. Charles, Texas City, and Three Rivers Refineries; the U.S. Mid-Continent region includes the Ardmore, McKee, and Memphis Refineries; the North Atlantic region includes the Pembroke and Quebec City Refineries; and the U.S.West Coast region includes the Benicia and Wilmington Refineries.

(i) U.S. Mid-Continent product specifications for gasoline changed on September 16, 2013 to CBOB gasoline. Therefore, average market reference prices for comparable products meeting the new specifications required in this region are now being provided for all periods presented.

General

Operating revenues increased 11 percent (or $13.3 billion) for the year ended December 31, 2012 compared to the year ended December 31, 2011 primarily as a result of higher average refined product prices for most of the products we produce and higher throughput volumes between the two years related to our refining segment operations. Refined product prices are most significantly influenced by the price of crude oil, which is a worldwide commodity whose price is influenced by many factors, including, but not limited to, worldwide supply and demand characteristics, worldwide political conditions, and worldwide economic conditions. However, regional factors also impact the price of refined product prices in those geographic regions. Regional factors can be similar to those that affect the worldwide price of crude oil, but they can also be significantly influenced by weather conditions that disrupt the supply of and demand for refined products in the region. For example, in October 2012, Hurricane Sandy struck the U.S. East Coast and disrupted the supply of refined products in that region for some time, which contributed to the increase of $5.99 per barrel in the North Atlantic benchmark reference price of CBOB gasoline in 2012 compared to 2011. The higher throughput volumes in 2012 resulted primarily from the incremental throughput of 75,000 BPD from the Meraux Refinery, which was acquired on October 1, 2011, and incremental throughput of 95,000 BPD from the Pembroke Refinery, which was acquired on August 1, 2011.

Operating income increased $330 million and income from continuing operations before income tax expense increased $384 million for the year ended December 31, 2012 compared to the amounts reported for the year ended December 31, 2011 due to a $934 million increase in refining segment operating income, a $33 million decrease in retail segment operating income, a $443 million decrease in ethanol segment operating income, and a $128 million increase in corporate expenses. The reasons for these changes are described below.

Refining

Refining segment operating income increased from $3.5 billion for the year ended December 31, 2011 to $4.5 billion for the year ended December 31, 2012. This increase was impacted by asset impairment losses of $928 million related to the Aruba Refinery and $65 million related to cancelled capital projects in 2012, $41 million of severance expense related to the Aruba Refinery, and a $542 million loss on derivative contracts in 2011. (See Notes 4 and 10 of Notes to Consolidated Financial Statements for further discussions of the asset impairment losses and the severance expense, respectively). Excluding these amounts, our refining segment operating income increased $1.4 billion from $4.1 billion for the year ended December 31, 2011 to $5.5 billion for the year ended December 31, 2012. This $1.4 billion improvement in operating income was primarily due to a $1.7 billion increase in refining margin, partially offset by a $262 million increase in operating expenses.

The $1.7 billion increase in refining margin (a $1.05 per barrel, or 11 percent, increase between 2012 and 2011) was primarily the result of improvements in the margin generated in our U.S. Mid-Continent and North Atlantic regions, which experienced increases in refining margin of $526 million (a $2.58 per barrel increase), and $821 million (a $3.81 per barrel increase), respectively.

The $526 million increase in refining margin in the U.S. Mid-Continent region was largely due to improved gasoline and distillate margins in that region in 2012 compared to 2011. For example, the U.S. Mid-Continent benchmark reference margins for CBOB gasoline (conventional 87 gasoline prior to September 16, 2013) and ultra-low-sulfur diesel, a type of distillate, increased year over year by $3.03 per barrel and $3.90 per barrel, respectively, and these increases were primarily the result of a $1.67 per barrel increase in the discount between the price of WTI crude oil versus Brent crude oil. Brent crude oil is the type of crude oil used by the market to set the price of refined products, but our refineries in the U.S. Mid-Continent region primarily process WTI-type crude oil; therefore, the increase in the price discount between WTI crude oil versus Brent crude oil had a positive impact to our refining margin in this region of approximately $300 million. WTI crude oil priced at a significant discount to Brent crude oil during 2012 because of increases in crude oil reserves within the U.S. Mid-Continent region and increased deliveries of crude oil from Canada into that region, coupled with the inability to transport significant quantities of that crude oil to refineries in other regions of the country.

The $821 million increase in refining margin in the North Atlantic region was also due to improved gasoline and distillate margins in that region in 2012 compared to 2011. For example, the North Atlantic benchmark reference margins for CBOB gasoline and ultra-low-sulfur diesel increased year over year by $4.71 per barrel and $3.42 per barrel, respectively, and these increases were due largely to a reduction in the supply of refined products, which resulted from the continued shutdown of refineries in the U.S. East Coast, Caribbean, and

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Western Europe during 2012, and supply disruptions caused by Hurricane Sandy, which struck the U.S. East Coast in October 2012.

The increase of $262 million in operating expenses discussed above was primarily due to an increase of $123 million in operating expenses of the Meraux Refinery, an increase of $214 million in operating expenses incurred by the Pembroke Refinery, and a decrease of $123 million in operating expenses incurred by the Aruba Refinery. We acquired the Pembroke Refinery on August 1, 2011 and the Meraux Refinery on October 1, 2011; therefore, operating expenses for 2011 only reflected five months of operating expenses of the Pembroke Refinery and three months of operating expenses of the Meraux Refinery. In addition, in March 2012, we suspended the operations of the Aruba Refinery, which resulted in a significant decrease in operating expenses related to that refinery in 2012. The remaining increase in operating expenses of $48 million was primarily due to an increase of $31 million in employee-related expenses due to higher compensation expense related to merit increases and promotions and higher expenses for employee benefit costs, an increase of $9 million in catalyst and chemical costs due to higher prices of rare earth metals used in our fluid catalytic cracking units, an increase of $61 million in ad valorem taxes and insurance expense due to increased insurance reserves in 2012 combined with a nonrecurring favorable ad valorem tax adjustment in 2011, and a decrease of $63 million in energy costs due to lower natural gas prices. Even though operating expenses increased year over year, operating expenses per barrel in 2012 were comparable to 2011 due to the incremental throughput of 179,000 BPD, which primarily resulted from the incremental throughput of the Pembroke and Meraux Refineries discussed above.

Retail

Retail operating income was $348 million for the year ended December 31, 2012 compared to $381 million for the year ended December 31, 2011. This 9 percent (or $33 million) decrease was primarily due to a $21 million noncash asset impairment loss related to certain convenience stores (see Note 4 of Notes to Consolidated Financial Statements), a $56 million decrease in fuel margin from our Canadian retail operations, and a $41 million increase in fuel margin in our U.S. retail operations.

The Canadian retail fuel margin for 2012 was impacted by a decline in fuel volumes sold as a result of fewer retail sites combined with a decline in the fuel margin per gallon, which was due to pricing pressure from our competitors and changes in wholesale motor fuel prices during the year. Our U.S. retail fuel margin improved during 2012 due to increased fuel volumes sold as a result of more retail sites combined with improved fuel margin per gallon as wholesale motor fuel prices peaked in March 2012 and declined throughout the remainder of the year.

Ethanol

Ethanol segment operating loss was $47 million for the year ended December 31, 2012 compared to operating income of $396 million for the year ended December 31, 2011. This decrease of $443 million was primarily due to a $507 million decrease in gross margin, partially offset by a $67 million decrease in operating expenses.

The decrease in gross margin was due to a 56 percent decrease in the gross margin per gallon of ethanol production (a $0.38 per gallon decrease between the comparable periods) primarily due to lower ethanol prices in 2012 versus 2011. Ethanol prices during 2012 were pressured by a surplus of ethanol supply due to reduced demand for ethanol associated with the decline in gasoline demand in the U.S., lower exports of ethanol to Europe, and increased imports of ethanol from Brazil. In addition, ethanol production decreased 385,000 gallons per day between the comparable periods due to lower utilization rates at our ethanol plants during 2012. The reduction in operating expenses was due primarily to a $57 million decrease in energy

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costs resulting from decreased consumption because of the lower utilization rates previously discussed, combined with lower natural gas prices versus the comparable period of 2011.

Corporate Expenses and Other

General and administrative expenses increased $127 million for the year ended December 31, 2012 compared to the year ended December 31, 2011 due to $58 million in administrative costs related to our European operations, which we acquired on August 1, 2011, a $23 million increase in employee benefits expense (primarily related to increased costs for medical and retirement benefits), and favorable legal settlements of $47 million in 2011, which did not recur in 2012.

“Other income, net” for the year ended December 31, 2012 decreased $34 million from the year ended December 31, 2011 due to an increase of $15 million of foreign currency transaction losses, an $11 million reduction in interest income due to the collection of a note receivable from PBF Holdings LLC in February 2012, and a $7 million reduction in bank interest income due to lower levels of temporary cash investments during 2012 as compared to the prior year.

“Interest and debt expense, net of capitalized interest” for the year ended December 31, 2012 decreased $88 million from the year ended December 31, 2011. This decrease is primarily due to an increase of $69 million in capitalized interest related to an increase in capital expenditures between the years and a $33 million favorable impact from the decrease in average borrowings, partially offset by a $12 million write-off of unamortized debt discounts related to the early redemption of certain industrial revenue bonds in the first quarter of 2012.

Income tax expense for the year ended December 31, 2012 increased $400 million from the year ended December 31, 2011 partially as a result of higher operating income in 2012. The variation in the customary relationship between income tax expense and income from continuing operations before income tax expense for the year ended December 31, 2012 was primarily due to not recognizing the tax benefits associated with the asset impairment loss of $928 million and the severance expense of $41 million related to the Aruba Refinery as we do not expect to realize a tax benefit from these losses.

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LIQUIDITY AND CAPITAL RESOURCES

Cash Flows for the Year Ended December 31, 2013

Net cash provided by operating activities for the year ended December 31, 2013 was $5.6 billion compared to $5.3 billion for the year ended December 31, 2012. Changes in cash provided by or used for working capital during the years ended December 31, 2013 and 2012 are shown in Note 19 of Notes to Consolidated Financial Statements.

The net cash generated from operating activities during the year ended December 31, 2013 combined with $735 million of net cash received in connection with the separation of our retail business (consisting of $550 million of proceeds on short-term debt, a $500 million cash distribution from CST less $315 million of cash retained by CST), and $525 million of proceeds on short-term debt related to the disposition of our retained interest in CST were used mainly to:

- fund $2.8 billion of capital expenditures and deferred turnaround and catalyst costs;
- make scheduled long-term note repayments of $480 million;
- make a short-term debt repayment of $58 million;
- purchase common stock for treasury of $928 million;
- pay common stock dividends of $462 million; and
- increase available cash on hand by $2.2 billion.

In addition, VLP completed its initial public offering of common units for net proceeds of $369 million. Because we consolidate VLP's financial statements, the total cash reported by us also increased by these net proceeds; however, such proceeds can only be used by VLP for its purposes.

Cash Flows for the Year Ended December 31, 2012

Net cash provided by operating activities for the year ended December 31, 2012 was $5.3 billion compared to $4.0 billion for the year ended December 31, 2011. The increase in cash generated from operating activities was primarily due to the increase in operating income discussed above under "RESULTS OF OPERATIONS," after excluding the effect of the asset impairment loss included in the 2012 operating income that had no effect on cash. Changes in cash provided by or used for working capital during the years ended December 31, 2012 and 2011 are shown in Note 19 of Notes to Consolidated Financial Statements.

The net cash generated from operating activities during the year ended December 31, 2012 combined with $300 million of proceeds from the remarketing of the 4.0% Gulf Opportunity Zone Revenue Bonds Series 2010 (GO Zone Bonds), $1.1 billion of borrowings under our revolving credit facility, and $1.5 billion of proceeds from the sale of receivables under our accounts receivable sales facility were used mainly to:

- fund $3.4 billion of capital expenditures and deferred turnaround and catalyst costs;
- redeem our Series 1997 5.6%, Series 1998 5.6%, Series 1999 5.7%, Series 2001 6.65%, and Series 1997A 5.45% industrial revenue bonds for $108 million;
- make scheduled long-term note repayments of $754 million;
- repay borrowings under our revolving credit facility of $1.1 billion;
- make repayments under our accounts receivable sales facility of $1.7 billion;
- purchase common stock for treasury of $281 million;
- pay common stock dividends of $360 million; and
- increase available cash on hand by $699 million.

Capital Investments

Our operations, especially those of our refining segment, are highly capital intensive. Each of our refineries comprises a large base of property assets, consisting of a series of interconnected, highly integrated and

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interdependent crude oil processing facilities and supporting logistical infrastructure (Units), and these Units are improved continuously. The cost of improvements, which consist of the addition of new Units and betterments of existing Units, can be 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 different types of crude oil and refine crude oil into products with higher market values. Therefore, many of our improvements do not increase throughput capacity significantly.

For 2014, we expect to incur approximately $2.3 billion for capital expenditures and approximately $700 million for deferred turnaround and catalyst costs. The capital expenditure estimate excludes expenditures related to potential strategic acquisitions. We continuously evaluate our capital budget and make changes as conditions warrant.

Contractual Obligations

Our contractual obligations as of December 31, 2013 are summarized below (in millions).

	Payments Due by Period						
	2014	2015	2016	2017	2018	Thereafter	Total
Debt and capital lease obligations (including interest on capital lease obligations)	$308	$483	$7	$957	$6	$4,851	$6,612
Operating lease obligations	305	230	162	111	95	321	1,224
Purchase obligations	33,159	3,501	994	453	279	1,126	39,512
Other long-term liabilities	—	138	113	112	103	863	1,329
Total	$33,772	$4,352	$1,276	$1,633	$483	$7,161	$48,677

Debt and Capital Lease Obligations

During 2013, we made scheduled long-term note repayments of $480 million as described in Note 11 of Notes to Consolidated Financial Statements.

We have an accounts receivable sales facility with a group of third-party entities and financial institutions to sell eligible trade receivables on a revolving basis up to $1.5 billion. As of December 31, 2013, the amount of eligible receivables sold was $100 million. All amounts outstanding under this facility are reflected as debt.

Our debt and financing 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 by the ratings agencies, the cost of borrowings under some of our bank credit facilities and other arrangements

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would increase. As of December 31, 2013, all of our ratings on our senior unsecured debt are at or above investment grade level as follows:

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

Operating Lease Obligations

Our operating lease obligations include leases for land, office facilities and equipment, transportation equipment, time charters for ocean-going tankers and coastal vessels, dock facilities, and various facilities and equipment used in the storage, transportation, production, and sale of refinery feedstocks, refined product, and corn inventories. Operating lease obligations include all operating leases that have initial or remaining noncancelable terms in excess of one year, and are not reduced by minimum rentals to be received by us under subleases.

Purchase Obligations

A purchase obligation is an enforceable and legally binding agreement to purchase goods or services that specifies significant terms, including (i) fixed or minimum quantities to be purchased, (ii) fixed, minimum, or variable price provisions, and (iii) the approximate timing of the transaction. We have various purchase obligations including industrial gas and chemical supply arrangements (such as hydrogen supply arrangements), crude oil and other feedstock supply arrangements, and various throughput and terminalling agreements. We enter into these contracts to ensure an adequate supply of utilities and feedstock and adequate storage capacity to operate our refineries. Substantially all of our purchase obligations are based on market prices or adjustments based on market indices. Certain of these purchase obligations include fixed or minimum volume requirements, while others are based on our usage requirements. The purchase obligation amounts shown in the table above include both short- and long-term obligations and are based on (a) fixed or minimum quantities to be purchased and (b) fixed or estimated prices to be paid based on current market conditions. As of December 31, 2013, there was no significant change in the amount of our short- and long-term purchase obligations as compared to December 31, 2012.

Other Long-term Liabilities

Our other long-term liabilities are described in Note 10 of Notes to Consolidated Financial Statements. For purposes of reflecting amounts for other long-term liabilities in the table above, we made our best estimate of expected payments for each type of liability based on information available as of December 31, 2013.

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Other Commercial Commitments

As of December 31, 2013, our outstanding letters of credit under our committed lines of credit were as follows (in millions):

	Borrowing Capacity	Expiration	Outstanding Letters of Credit
Letter of credit facilities	$ 550	June 2014	$ 278
U.S. revolving credit facility	$ 3,000	November 2018	$ 59
Canadian revolving credit facility	C$50	November 2014	C$10

As of December 31, 2013, we had no amounts borrowed under our revolving credit facilities. The letters of credit outstanding as of December 31, 2013 expire during 2014 and 2015.

Off-Balance Sheet Arrangements

We have not entered into any transactions, agreements, or other contractual arrangements that would result in off-balance sheet liabilities.

Other Matters Impacting Liquidity and Capital Resources

Stock Purchase Programs

As of December 31, 2013, we have approvals under common stock purchase programs to purchase approximately $2.6 billion of our common stock. In January 2014, we purchased 4 million shares for $208 million.

Pension Plan Funding

We plan to contribute approximately $38 million to our pension plans and $19 million to our postretirement plans during 2014.

On February 15, 2013, we announced changes to certain of our pension plans that reduced our pension obligations. In addition, we expect that these changes will also reduce our benefit costs for future years, as further discussed in Note 14 of Notes to Consolidated Financial Statements.

Environmental Matters

Our operations are subject to extensive environmental regulations by governmental authorities 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 operating facilities could require material additional expenditures to comply with environmental laws and regulations. See Notes 10 and 12 of Notes to Consolidated Financial Statements for a further discussion of our environmental matters.

Tax Matters

During the first quarter of 2014, we expect to pay approximately $400 million in tax payments that relate to 2013 and that were recorded in income taxes payable as of December 31, 2013. In addition, we currently believe the cash we will pay for income taxes for 2014 will increase and that such amount may exceed the total income tax expense that will be reflected on our statement of income. This belief is primarily due to an expected decrease in deductions that we will claim on our U.S. federal income tax return for depreciation

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on our property, plant, and equipment. In prior years, the U.S. federal government enacted certain legislation that provided for the deduction of depreciation on an accelerated basis on newly built equipment as a means of encouraging capital investment by businesses. This legislation, however, generally does not extend beyond 2013. Although we expect the amount of cash required to pay our 2014 income taxes to increase compared to recent prior years, we believe that we will generate sufficient cash from operations and have sufficient cash on hand to make our tax payments as they become due.

As of December 31, 2013, the IRS has ongoing tax audits related to our U.S. federal tax returns from 2002 through 2011. We have received Revenue Agent Reports in connection with the 2002 through 2009 audits, and we are vigorously contesting certain tax positions and assertions from the IRS. We made significant progress during 2013 in resolving certain of these matters, and in January 2014, we settled the audit related to the 2004 and 2005 tax years for a group of our subsidiaries for an amount consistent with the recorded amount of unrecognized tax benefits associated with that audit. We are continuing to work with the IRS to resolve the remaining matters and expect to settle other audits within the next 12 months for amounts consistent with the recorded amounts of unrecognized tax benefits associated with those audits. Because these settlements are expected to occur in 2014, we classified certain of our long-term uncertain tax position liabilities to current liabilities as of December 31, 2013. The total amount of uncertain tax position liabilities was $443 million as of December 31, 2013, with $238 million reflected in “income taxes payable” and $205 million reflected in “other long-term liabilities”, and this total amount did not change significantly during the year ended December 31, 2013. Should we ultimately settle for amounts consistent with our estimates, we believe that we will have sufficient cash on hand at that time to make such payments.

Cash Held by Our International Subsidiaries

We operate in countries outside the U.S. through subsidiaries incorporated in these countries, and the earnings of these subsidiaries are taxed by the countries in which they are incorporated. We intend to reinvest these earnings indefinitely in our international operations even though we are not restricted from repatriating such earnings to the U.S. in the form of cash dividends. Should we decide to repatriate such earnings, we would incur and pay taxes on the amounts repatriated. In addition, such repatriation could cause us to record deferred tax expense that could significantly impact our results of operations, as further discussed in Note 16 of Notes to Consolidated Financial Statements. We believe, however, that a substantial portion of our international cash can be returned to the U.S. without significant tax consequences through means other than a repatriation of earnings. As of December 31, 2013, $1.1 billion of our cash and temporary cash investments was held by our international subsidiaries.

Financial Regulatory Reform

In July 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (Wall Street Reform Act). Key provisions of the Wall Street Reform Act create new statutory requirements that require most derivative instruments to be traded on exchanges and routed through clearinghouses, as well as impose new recordkeeping and reporting responsibilities on market participants. While certain final rules implementing the Wall Street Reform Act became effective in the fourth quarter of 2012, others continue to become effective in 2013 and 2014. Although we cannot predict the ultimate impact of these rules, which may result in higher clearing costs and more reporting requirements with respect to our derivative activities, we believe they will not have a material impact on our financial position, results of operations, or liquidity.

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.

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.

NEW ACCOUNTING PRONOUNCEMENTS

As discussed in Note 1 of Notes to Consolidated Financial Statements, certain new financial accounting pronouncements will become effective for our financial statements in the future. The adoption of these pronouncements is not expected to have a material effect on our financial statements.

CRITICAL ACCOUNTING POLICIES INVOLVING CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with U.S. generally accepted accounting principles requires us to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. The following summary provides further information about our critical accounting policies that involve critical accounting estimates, and should be read in conjunction with Note 1 of Notes to Consolidated Financial Statements, which summarizes our significant accounting policies. The following accounting policies involve estimates that are considered critical due to the level of subjectivity and judgment involved, as well as the impact on our financial position and results of operations. We believe that all of our estimates are reasonable.

Property, Plant, and Equipment

Depreciation of property assets used in our refining segment 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 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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Impairment of Assets
Long-lived assets (which include property, plant, and equipment, intangible assets, and refinery turnaround and catalyst costs) and equity method investments are tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. An impairment loss should be recognized if the carrying amount of the asset exceeds its fair value.

In order to test for recoverability, we must make estimates of projected cash flows related to the asset being evaluated, which include, but are not limited to, assumptions about the use or disposition of the asset, its estimated remaining life, and future expenditures necessary to maintain its existing service potential. In order to determine fair value, management must make certain estimates and assumptions including, among other things, an assessment of market conditions, projected cash flows, investment rates, interest/equity rates, and growth rates, that could significantly impact the fair value of the asset being tested for impairment. Our impairment evaluations are based on assumptions that we deem to be reasonable. Providing sensitivity analyses if other assumptions were used in performing the impairment evaluations is not practicable due to the significant number of assumptions involved in the estimates. See Note 4 of Notes to Consolidated Financial Statements for a further discussion of our asset impairment analysis and certain losses resulting from those analyses.

Environmental Matters
Our operations are subject to extensive environmental regulations by governmental authorities relating primarily to the discharge of materials into the environment, waste management, and pollution prevention measures. Future legislative action and regulatory initiatives, as discussed in Note 12 of Notes to Consolidated Financial Statements could result in changes to required operating permits, additional remedial actions, or increased capital expenditures and operating costs that cannot be assessed with certainty at this time.

Accruals for environmental liabilities are based on best estimates of probable undiscounted future costs over a 20-year time period using currently available technology and applying current regulations, as well as our own internal environmental policies. However, environmental liabilities are difficult to assess and estimate due to uncertainties related to the magnitude of possible remediation, the timing of such remediation, and the determination of our obligation in proportion to other parties. Such estimates are subject to change due to many factors, including the identification of new sites requiring remediation, changes in environmental laws and regulations and their interpretation, additional information related to the extent and nature of remediation efforts, and potential improvements in remediation technologies. An estimate of the sensitivity to earnings for changes in those factors is not practicable due to the number of contingencies that must be assessed, the number of underlying assumptions, and the wide range of possible outcomes.

The amount of and changes in our accruals for environmental matters as of and for the years ended December 31, 2013, 2012, and 2011 is included in Note 10 of Notes to Consolidated Financial Statements.

Pension and Other Postretirement Benefit Obligations
We have significant pension and other postretirement benefit liabilities and costs that are developed from actuarial valuations. Inherent in these valuations are key assumptions including discount rates, expected return on plan assets, future compensation increases, and health care cost trend rates, and these assumptions are disclosed and described in Note 14 of Notes to Consolidated Financial Statements. Changes in these assumptions are primarily influenced by factors outside our control. For example, the discount rate assumption represents a yield curve comprised of various long-term bonds that have an average rating of double-A when averaging all available ratings by the recognized rating agencies, while the expected return on plan assets is based on a compounded return calculated assuming an asset allocation that is representative of the asset mix in our pension plans. To determine the expected return on plan assets, we utilized a forward-

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looking model of asset returns. The historical geometric average return over the 10 years prior to December 31, 2013 was 8.86 percent. The actual return on assets for the years ended December 31, 2013, 2012 and 2011 was 19.38 percent, 11.84 percent, and 0.10 percent, respectively. These assumptions can have a significant effect on the amounts reported in our financial statements. For example, a 0.25 percent decrease in the assumptions related to the discount rate or expected return on plan assets or a 0.25 percent increase in the assumptions related to the health care cost trend rate or rate of compensation increase would have the following effects on the projected benefit obligation as of December 31, 2013 and net periodic benefit cost for the year ending December 31, 2014 (in millions):

	Pension Benefits	Other Postretirement Benefits
Increase in projected benefit obligation resulting from:		
Discount rate decrease	$83	$10
Compensation rate increase	6	n/a
Health care cost trend rate increase	n/a	1
Increase in expense resulting from:		
Discount rate decrease	8	—
Expected return on plan assets decrease	4	n/a
Compensation rate increase	2	n/a
Health care cost trend rate increase	n/a	—

See Note 14 of Notes to Consolidated Financial Statements for a further discussion of our pension and other postretirement benefit obligations.

Tax Matters

We record tax liabilities based on our assessment of existing tax laws and regulations. A contingent loss related to an indirect tax claim is recorded if the loss is both probable and estimable. The recording of our tax liabilities requires significant judgments and estimates. Actual tax liabilities can vary from our estimates for a variety of reasons, including different interpretations of tax laws and regulations and different assessments of the amount of tax due. In addition, in determining our income tax provision, we must assess the likelihood that our deferred tax assets, primarily consisting of net operating loss and tax credit carryforwards, will be recovered through future taxable income. Significant judgment is required in estimating the amount of valuation allowance, if any, that should be recorded against those deferred income tax assets. If our actual results of operations differ from such estimates or our estimates of future taxable income change, the valuation allowance may need to be revised. However, an estimate of the sensitivity to earnings that would result from changes in the assumptions and estimates used in determining our tax liabilities is not practicable due to the number of assumptions and tax laws involved, the various potential interpretations of the tax laws, and the wide range of possible outcomes. See Notes 12 and 16 of Notes to Consolidated Financial Statements for a further discussion of our tax liabilities.

Legal Matters

A variety of claims have been made against us in various lawsuits. We record a liability related to a loss contingency attributable to such legal matters if we determine that it is probable that a loss has been incurred and that the loss is reasonably estimable. The recording of such liabilities requires judgments and estimates, the results of which can vary significantly from actual litigation results due to differing interpretations of

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relevant law and differing opinions regarding the degree of potential liability and the assessment of reasonable damages. However, an estimate of the sensitivity to earnings if other assumptions were used in recording our legal liabilities is not practicable due to the number of contingencies that must be assessed and the wide range of reasonably possible outcomes, both in terms of the probability of loss and the estimates of such loss.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

COMMODITY PRICE RISK

We are exposed to market risks related to the volatility in 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 inventory levels (determined on a last-in, first-out (LIFO) basis) differ from our previous year-end LIFO inventory levels and
- forecasted feedstock and refined product purchases, refined product sales, 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.

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

	Derivative Instruments Held For	
	Non-Trading Purposes	Trading Purposes
December 31, 2013:		
Gain (loss) in fair value resulting from:		
10% increase in underlying commodity prices	$(91)	$3
10% decrease in underlying commodity prices	91	(2)
December 31, 2012:		
Gain (loss) in fair value resulting from:		
10% increase in underlying commodity prices	(131)	(9)
10% decrease in underlying commodity prices	135	(1)

See Note 21 of Notes to Consolidated Financial Statements for notional volumes associated with these derivative contracts as of December 31, 2013.

COMPLIANCE PROGRAM PRICE RISK

We are exposed to market risk related to the volatility in the price of biofuel credits needed to comply with various governmental and regulatory programs. To manage this risk, we enter into contracts to purchase

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these credits when prices are deemed favorable. Some of these contracts are derivative instruments; however, we elect the normal purchase exception and do not record these contracts at their fair values. As of December 31, 2013, there was no gain or loss in the fair value of derivative instruments that would result from a 10 percent increase or decrease in the underlying price of the contracts. See Note 21 of Notes to Consolidated Financial Statements for a discussion about these compliance programs.

INTEREST RATE RISK

The following table provides information about our debt instruments, excluding capital lease obligations (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 December 31, 2013 and 2012.

	December 31, 2013 Expected Maturity Dates							
	2014	2015	2016	2017	2018	There-after	Total	Fair Value
Debt:								
Fixed rate	$200	$475	$—	$950	$—	$4,824	$6,449	$7,559
Average interest rate	4.8 %	5.2 %	— %	6.4 %	— %	7.3 %	6.9 %	
Floating rate	$100	$—	$—	$—	$—	$—	$100	$100
Average interest rate	0.9 %	— %	— %	— %	— %	— %	0.9 %	

	December 31, 2012 Expected Maturity Dates							
	2013	2014	2015	2016	2017	There-after	Total	Fair Value
Debt:								
Fixed rate	$480	$200	$475	$—	$950	$4,824	$6,929	$8,521
Average interest rate	5.5 %	4.8 %	5.2 %	— %	6.4 %	7.3 %	6.8 %	
Floating rate	$100	$—	$—	$—	$—	$—	$100	$100
Average interest rate	0.9 %	— %	— %	— %	— %	— %	0.9 %	

FOREIGN CURRENCY RISK

As of December 31, 2013, we had commitments to purchase $716 million of U.S. dollars. Our market risk was minimal on the contracts, as the majority of them matured on or before January 31, 2014, resulting in a gain of $12 million in the first quarter of 2014.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate "internal control over financial reporting" (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) for Valero. Our management evaluated the effectiveness of Valero's internal control over financial reporting as of December 31, 2013. In its evaluation, management used the criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management believes that as of December 31, 2013, our internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on the effectiveness of our internal control over financial reporting, which begins on page 58 of this report.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
of Valero Energy Corporation and subsidiaries:

We have audited the accompanying consolidated balance sheets of Valero Energy Corporation and subsidiaries (the Company) as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2013. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States) (the PCAOB). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Valero Energy Corporation and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the PCAOB, the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 27, 2014 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

San Antonio, Texas
February 27, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
of Valero Energy Corporation and subsidiaries:

We have audited Valero Energy Corporation and subsidiaries' (the Company's) internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States) (the PCAOB). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Valero Energy Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by COSO.

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We also have audited, in accordance with the standards of the PCAOB, the consolidated balance sheets of Valero Energy Corporation and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2013, and our report dated February 27, 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

San Antonio, Texas
February 27, 2014

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

	December 31, 2013	2012
ASSETS		
Current assets:		
Cash and temporary cash investments	$4,292	$1,723
Receivables, net	8,751	8,167
Inventories	5,758	5,973
Income taxes receivable	72	169
Deferred income taxes	266	274
Prepaid expenses and other	138	154
Total current assets	19,277	16,460
Property, plant, and equipment, at cost	33,933	34,132
Accumulated depreciation	(8,226)	(7,832)
Property, plant, and equipment, net	25,707	26,300
Intangible assets, net	156	213
Deferred charges and other assets, net	2,120	1,504
Total assets	$47,260	$44,477
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of debt and capital lease obligations	$303	$586
Accounts payable	9,931	9,348
Accrued expenses	522	590
Taxes other than income taxes	1,345	1,026
Income taxes payable	773	1
Deferred income taxes	249	378
Total current liabilities	13,123	11,929
Debt and capital lease obligations, less current portion	6,261	6,463
Deferred income taxes	6,601	5,860
Other long-term liabilities	1,329	2,130
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	7,187	7,322
Treasury stock, at cost; 137,932,138 and 121,406,520 common shares	(7,054)	(6,437)
Retained earnings	18,970	17,032
Accumulated other comprehensive income	350	108
Total Valero Energy Corporation stockholders’ equity	19,460	18,032
Noncontrolling interests	486	63
Total equity	19,946	18,095
Total liabilities and equity	$47,260	$44,477

See Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(Millions of Dollars, Except per Share Amounts)

	Year Ended December 31,		
	2013	2012	2011
Operating revenues	$138,074	$139,250	$125,987
Costs and expenses:			
Cost of sales	127,316	127,268	115,719
Operating expenses:			
Refining	3,704	3,668	3,406
Retail	226	686	678
Ethanol	387	332	399
General and administrative expenses	758	698	571
Depreciation and amortization expense	1,720	1,574	1,534
Asset impairment losses	—	1,014	—
Total costs and expenses	134,111	135,240	122,307
Operating income	3,963	4,010	3,680
Gain on disposition of retained interest in CST Brands, Inc.	325	—	—
Other income, net	59	9	43
Interest and debt expense, net of capitalized interest	(365)	(313)	(401)
Income from continuing operations before income tax expense	3,982	3,706	3,322
Income tax expense	1,254	1,626	1,226
Income from continuing operations	2,728	2,080	2,096
Loss from discontinued operations, net of income taxes	—	—	(7)
Net income	2,728	2,080	2,089
Less: Net income (loss) attributable to noncontrolling interests	8	(3)	(1)
Net income attributable to Valero Energy Corporation stockholders	$2,720	$2,083	$2,090
Net income attributable to Valero Energy Corporation stockholders:			
Continuing operations	$2,720	$2,083	$2,097
Discontinued operations	—	—	(7)
Total	$2,720	$2,083	$2,090
Earnings per common share:			
Continuing operations	$4.99	$3.77	$3.70
Discontinued operations	—	—	(0.01)
Total	$4.99	$3.77	$3.69
Weighted-average common shares outstanding (in millions)	542	550	563
Earnings per common share – assuming dilution:			
Continuing operations	$4.97	$3.75	$3.69
Discontinued operations	—	—	(0.01)
Total	$4.97	$3.75	$3.68
Weighted-average common shares outstanding – assuming dilution (in millions)	548	556	569
Dividends per common share	$0.85	$0.65	$0.30

See Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2013	2012	2011
Net income	$2,728	$2,080	$2,089
Other comprehensive income (loss):			
Foreign currency translation adjustment	(98)	164	(122)
Net gain (loss) on pension and other postretirement benefits	763	(211)	(292)
Net gain (loss) on derivative instruments designated and qualifying as cash flow hedges	(2)	(28)	29
Other comprehensive income (loss) before income tax expense (benefit)	663	(75)	(385)
Income tax expense (benefit) related to items of other comprehensive income (loss)	262	(87)	(93)
Other comprehensive income (loss)	401	12	(292)
Comprehensive income	3,129	2,092	1,797
Less: Comprehensive income (loss) attributable to noncontrolling interests	8	(3)	(1)
Comprehensive income attributable to Valero Energy Corporation stockholders	$3,121	$2,095	$1,798

See Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY
(Millions of Dollars)

	Valero Energy Corporation Stockholders' Equity							
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total	Non-controlling Interests	Total Equity
Balance as of December 31, 2010	$7	$7,704	$(6,462)	$13,388	$ 388	$15,025	$ —	$15,025
Net income (loss)	—	—	—	2,090	—	2,090	(1)	2,089
Dividends on common stock	—	—	—	(169)	—	(169)	—	(169)
Stock-based compensation expense	—	57	—	—	—	57	—	57
Tax deduction in excess of stock-based compensation expense	—	22	—	—	—	22	—	22
Transactions in connection with stock-based compensation plans:								
Stock issuances	—	(287)	336	—	—	49	—	49
Stock repurchases	—	(10)	(349)	—	—	(359)	—	(359)
Contributions from noncontrolling interest	—	—	—	—	—	—	23	23
Recognition of noncontrolling interests in Mainline Pipelines Limited in connection with Pembroke Acquisition	—	—	—	—	—	—	5	5
Acquisition of noncontrolling interests in Mainline Pipelines Limited	—	—	—	—	—	—	(5)	(5)
Other comprehensive loss	—	—	—	—	(292)	(292)	—	(292)
Balance as of December 31, 2011	7	7,486	(6,475)	15,309	96	16,423	22	16,445
Net income (loss)	—	—	—	2,083	—	2,083	(3)	2,080
Dividends on common stock	—	—	—	(360)	—	(360)	—	(360)
Stock-based compensation expense	—	57	—	—	—	57	—	57
Tax deduction in excess of stock-based compensation expense	—	29	—	—	—	29	—	29

Transactions in connection with stock-based compensation plans:								
Stock issuances	—	(260)	319	—	—	59	—	59
Stock repurchases	—	10	(163)	—	—	(153)	—	(153)
Stock repurchases under buyback program	—	—	(118)	—	—	(118)	—	(118)
Contributions from noncontrolling interest	—	—	—	—	—	—	44	44
Other comprehensive income	—	—	—	—	12	12	—	12
Balance as of December 31, 2012	7	7,322	(6,437)	17,032	108	18,032	63	18,095
Net income	—	—	—	2,720	—	2,720	8	2,728
Dividends on common stock	—	—	—	(462)	—	(462)	—	(462)
Stock-based compensation expense	—	64	—	—	—	64	—	64
Tax deduction in excess of stock-based compensation expense	—	47	—	—	—	47	—	47
Transactions in connection with stock-based compensation plans:								
Stock issuances	—	(243)	302	—	—	59	—	59
Stock repurchases	—	—	(236)	—	—	(236)	—	(236)
Stock repurchases under buyback program	—	—	(692)	—	—	(692)	—	(692)
Separation of retail business	—	(9)	9	(320)	(159)	(479)	—	(479)
Net proceeds from initial public offering of common units of Valero Energy Partners LP	—	—	—	—	—	—	369	369
Contributions from noncontrolling interests	—	—	—	—	—	—	46	46
Other	—	6	—	—	—	6	—	6
Other comprehensive income	—	—	—	—	401	401	—	401
Balance as of December 31, 2013	$7	$7,187	$(7,054)	$18,970	$350	$19,460	$486	$19,946

See Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2013	2012	2011
Cash flows from operating activities:			
Net income	$2,728	$2,080	$2,089
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	1,720	1,574	1,534
Gain on disposition of retained interest in CST Brands, Inc.	(325)	—	—
Asset impairment losses	—	1,014	—
Loss on sales of refinery assets, net	—	—	12
Stock-based compensation expense	64	58	58
Deferred income tax expense	501	963	461
Changes in current assets and current liabilities	922	(302)	81
Changes in deferred charges and credits and other operating activities, net	(46)	(117)	(197)
Net cash provided by operating activities	5,564	5,270	4,038
Cash flows from investing activities:			
Capital expenditures	(2,121)	(2,931)	(2,355)
Deferred turnaround and catalyst costs	(634)	(479)	(629)
Acquisition of Pembroke Refinery, net of cash acquired	—	—	(1,691)
Acquisition of Meraux Refinery	—	—	(547)
Proceeds from the sale of the Paulsboro Refinery	—	160	—
Other investing activities, net	(57)	(101)	(76)
Net cash used in investing activities	(2,812)	(3,351)	(5,298)
Cash flows from financing activities:			
Proceeds from debt borrowings	—	2,900	150
Repayments of debt	(480)	(3,612)	(778)
Proceeds from the exercise of stock options	59	59	49
Purchase of common stock for treasury	(928)	(281)	(349)
Common stock dividends	(462)	(360)	(169)
Net proceeds from initial public offering of common units of Valero Energy Partners LP	369	—	—
Contributions from noncontrolling interests	45	44	22
Disposition of retail business:			
Proceeds from short-term debt in anticipation of separation	550	—	—
Cash distributed to Valero by CST Brands, Inc.	500	—	—
Cash held and retained by CST Brands, Inc. upon separation	(315)	—	—
Proceeds from short-term debt related to disposition of retained interest	525	—	—
Repayments of short-term debt related to disposition of retained interest	(58)	—	—
Other financing activities, net	32	17	9
Net cash used in financing activities	(163)	(1,233)	(1,066)
Effect of foreign exchange rate changes on cash	(20)	13	16
Net increase (decrease) in cash and temporary cash investments	2,569	699	(2,310)
Cash and temporary cash investments at beginning of year	1,723	1,024	3,334
Cash and temporary cash investments at end of year	$4,292	$1,723	$1,024

See Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION
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. We are an independent petroleum refining and marketing company and own 16 refineries with a combined throughput capacity of approximately 3.1 million barrels per day as of December 31, 2013. We market branded and unbranded refined products on a wholesale basis in the United States (U.S.), Canada, the Caribbean, the United Kingdom (U.K.), and Ireland through an extensive bulk and rack marketing network and through approximately 7,400 outlets that carry the Valero®, Shamrock®, Ultramar®, Beacon®, and Texaco® brand names. We also own 10 ethanol plants in the U.S. that primarily produce ethanol with a combined production capacity of approximately 1.2 billion gallons per year as of December 31, 2013. Our operations are affected by:

- company-specific factors, primarily refinery utilization rates and refinery maintenance turnarounds;
- seasonal factors, such as the demand for refined products during the summer driving season and heating oil during the winter season; and
- industry factors, such as movements in and the level of crude oil prices including the effect of quality differentials between grades of crude oil, the demand for and prices of refined products, industry supply capacity, and competitor refinery maintenance turnarounds.

We have evaluated subsequent events that occurred after December 31, 2013 through the filing of this Form 10-K. Any material subsequent events that occurred during this time have been properly recognized or disclosed in these financial statements.

Significant Accounting Policies
Reclassifications
Certain amounts previously reported in our annual report on Form 10-K for the year ended December 31, 2012 have been reclassified to conform to the 2013 presentation.

Principles of Consolidation
General
These financial statements include the accounts of Valero and subsidiaries in which Valero has a controlling interest. Intercompany balances and transactions have been eliminated in consolidation. Investments in significant noncontrolled entities are accounted for using the equity method.

Noncontrolling Interests
Because of our controlling financial interest in each of the following entities, we have included their financial statements in our financial statements and have separately disclosed the related noncontrolling interests.

- Valero Energy Partners LP (VLP) is a master limited partnership formed in July 2013 to own, operate, develop, and acquire primarily fee-based crude oil and refined petroleum product pipelines and terminals. As further described in Note 5, VLP completed an initial public offering of its common units on December 16, 2013 and we owned a 70.6 percent controlling financial interest in VLP as of December 31, 2013.
- Diamond Green Diesel Holdings LLC (DGD Holdings) is a 50/50 joint venture with Darling Green Energy LLC, a subsidiary of Darling International, Inc., that constructed and now operates a biomass-

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

based diesel unit having a design feed capacity of 10,000 barrels per day that processes animal fats, used cooking oils, and other vegetable oils into renewable green diesel. As of December 31, 2013, we had loaned $221 million to a subsidiary of DGD Holdings to finance a portion of the construction costs of the unit. The unit began operations in June 2013.

- PI Dock Facilities LLC (PI Dock) is a 50/50 joint venture with TGSD PI, LLC that will construct and operate crude oil docks and related facilities near our Port Arthur Refinery. In December 2012, we agreed to lend PI Dock up to $90 million to finance the construction of the initial crude dock, which is expected to be completed in late third quarter or early fourth quarter of 2014. As of December 31, 2013, we had loaned PI Dock $13 million to finance its construction projects.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles (GAAP) requires us to make estimates and assumptions that affect the amounts reported in the 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.

Cash and Temporary Cash Investments

Our temporary cash investments are highly liquid, low-risk debt instruments that have a maturity of three months or less when acquired.

Receivables

Trade receivables are carried at original invoice amount. We maintain an allowance for doubtful accounts, which is adjusted based on management’s assessment of our customers’ historical collection experience, known credit risks, and industry and economic conditions.

Inventories

Inventories are carried at the lower of cost or market. The cost of refinery feedstocks purchased for processing, refined products, and grain and ethanol inventories are determined under the last-in, first-out (LIFO) method using the dollar-value LIFO method, with any increments valued based on average purchase prices during the year. The cost of feedstocks and products purchased for resale and the cost of materials and supplies are determined principally under the weighted-average cost method.

Property, Plant, and Equipment

The cost of property, plant, and equipment (property assets) purchased or constructed, including betterments of property assets, is capitalized. However, the cost of repairs to and normal maintenance of property assets is expensed as incurred. Betterments of property assets are those that 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 comprises 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

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 property assets used in our refining segment 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 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.

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.

Depreciation of property assets used in our ethanol segment and our former retail segment (see Note 3) is recorded on a straight-line basis over the estimated useful lives of the related assets. Leasehold improvements are amortized on a straight-line basis over the shorter of the lease term or the estimated useful life of the related asset. Assets acquired under capital leases are amortized on a straight-line basis over (i) the lease term if transfer of ownership does not occur at the end of the lease term or (ii) the estimated useful life of the asset if transfer of ownership does occur at the end of the lease term.

Deferred Charges and Other Assets

“Deferred charges and other assets, net” include the following:

- turnaround costs, which are incurred in connection with planned major maintenance activities at our refineries and ethanol plants and which are deferred when incurred and amortized on a straight-line basis over the period of time estimated to lapse until the next turnaround occurs;
- fixed-bed catalyst costs, representing the cost of catalyst that is changed out at periodic intervals when the quality of the catalyst has deteriorated beyond its prescribed function, which are deferred when incurred and amortized on a straight-line basis over the estimated useful life of the specific catalyst;
- investments in entities that we do not control; and

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

- other noncurrent assets such as investments of certain benefit plans (related primarily to certain U.S. nonqualified defined benefit plans whose plan assets are not protected from our creditors and therefore cannot be reflected as a reduction from our obligations under those pension plans), debt issuance costs, and various other costs.

Impairment of Assets
Long-lived assets, which include property, plant, and equipment, intangible assets, and refinery turnaround and catalysts costs, are tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. A long-lived asset is not recoverable if its carrying amount exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. If a long-lived asset is not recoverable, an impairment loss is recognized for the amount by which the carrying amount of the long-lived asset exceeds its fair value, with fair value determined based on discounted estimated net cash flows or other appropriate methods. See Note 4 for our impairment analysis of our long-lived assets.

We evaluate our equity method investments for impairment when there is evidence that we may not be able to recover the carrying amount of our investments or the investee is unable to sustain an earnings capacity that justifies the carrying amount. A loss in the value of an investment that is other than a temporary decline is recognized currently in income, and is based on the difference between the estimated current fair value of the investment and its carrying amount.

Environmental Matters
Liabilities for future remediation costs are recorded when environmental assessments and/or remedial efforts are probable and the costs can be reasonably estimated. Other than for assessments, the timing and magnitude of these accruals generally are based on the completion of investigations or other studies or a commitment to a formal plan of action. Amounts recorded for environmental liabilities have not been reduced by possible recoveries from third parties and have not been measured on a discounted basis.

Asset Retirement Obligations
We record a liability, which is referred to as an asset retirement obligation, at fair value for the estimated cost to retire a tangible long-lived asset at the time we incur that liability, which is generally when the asset is purchased, constructed, or leased. We record the liability when we have a legal obligation to incur costs to retire the asset and when a reasonable estimate of the fair value of the liability can be made. If a reasonable estimate cannot be made at the time the liability is incurred, we record the liability when sufficient information is available to estimate the liability's fair value.

Foreign Currency Translation
The functional currency of each of our international operations is generally the respective local currency, which includes the Canadian dollar, the Aruban florin, the pound sterling, and the euro. Balance sheet accounts are translated into U.S. dollars using exchange rates in effect as of the balance sheet date. Revenue and expense accounts are translated using the weighted-average exchange rates during the year presented. Foreign currency translation adjustments are recorded as a component of accumulated other comprehensive income.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revenue Recognition
Revenues for products sold by the refining and ethanol segments and our former retail segment (see Note 3) are recorded upon delivery of the products to our customers, which is the point at which title to the products is transferred, and when payment has either been received or collection is reasonably assured.

Excise taxes on sales by our U.S. retail system were presented on a gross basis. All other excise taxes are presented on a net basis.

We enter into certain purchase and sale arrangements with the same counterparty that are deemed to be made in contemplation of one another. We combine these transactions and, as a result, revenues and cost of sales are not recognized in connection with these arrangements. We also enter into refined product exchange transactions to fulfill sales contracts with our customers by accessing refined products in markets where we do not operate our own refineries. These refined product exchanges are accounted for as exchanges of non-monetary assets, and no revenues are recorded on these transactions.

Product Shipping and Handling Costs
Costs incurred for shipping and handling of products are included in cost of sales.

Cost of Biofuel Credits
We purchase biofuel credits (primarily Renewable Identification Numbers (RINs) in the U.S.) to comply with government regulations that require us to blend a certain percentage of biofuels into the products we produce, as further described in Note 21 under “Compliance Program Price Risk.” To the degree that we are unable to blend biofuels at the required percentage, we must purchase biofuel credits in the open market to meet our obligation. The cost of purchased biofuel credits is charged to cost of sales as such credits are needed to satisfy our obligation. To the extent we have not purchased enough biofuel credits to satisfy our obligation as of the balance sheet date, we charge cost of sales for such deficiency based on the market price of the biofuel credits as of the balance sheet date, and we record a liability for our obligation to purchase those credits. See Note 20 for disclosure of our fair value liability.

Stock-Based Compensation
Compensation expense for our share-based compensation plans is based on the fair value of the awards granted and is recognized in income on a straight-line basis over the requisite service period of each award. For new grants that have retirement-eligibility provisions, we use the non-substantive vesting period approach, under which compensation cost is recognized immediately for awards granted to retirement-eligible employees or over the period from the grant date to the date retirement eligibility is achieved if that date is expected to occur during the nominal vesting period.

Income Taxes
Income taxes are accounted for under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred amounts are measured using enacted tax rates expected to apply to taxable income in the year those temporary differences are expected to be recovered or settled.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We have elected to classify any interest expense and penalties related to the underpayment of income taxes in income tax expense.

Earnings per Common Share
Earnings per common share is computed by dividing net income by the weighted-average number of common shares outstanding for the year. Participating share-based payment awards, including shares of restricted stock granted under certain of our stock-based compensation plans, are included in the computation of basic earnings per share using the two-class method. Earnings per common share – assuming dilution reflects the potential dilution arising from our outstanding stock options and nonvested shares granted to employees in connection with our stock-based compensation plans. Potentially dilutive securities are excluded from the computation of earnings per common share – assuming dilution when the effect of including such shares would be antidilutive.

Financial Instruments
Our financial instruments include cash and temporary cash investments, receivables, payables, debt, capital lease obligations, commodity derivative contracts, and foreign currency derivative contracts. The estimated fair values of these financial instruments approximate their carrying amounts, except for certain debt as discussed in Note 20.

Derivatives and Hedging
All derivative instruments are recorded in the balance sheet as either assets or liabilities measured at their fair values. When we enter into a derivative instrument, it is designated as a fair value hedge, a cash flow hedge, an economic hedge, or a trading 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 hedging relationships (derivative instruments not designated as fair value or cash flow hedges) and for derivative instruments entered into 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 statements of cash flows.

New Accounting Pronouncements
In July 2013, the provisions of Accounting Standards Codification Topic 740, “Income Taxes,” were amended to provide specific guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists at the reporting date. The amendment requires entities to present an unrecognized tax benefit as a reduction to the deferred tax asset generated by the net operating loss carryforward, similar tax loss, or tax credit carryforward, if such items are available to be used to offset the unrecognized tax benefit. These provisions are effective for interim and annual reporting periods beginning after December 15, 2013 and should be applied prospectively to all unrecognized tax benefits that exist at the effective date, with retrospective application permitted. The adoption of this guidance effective January 1, 2014 will not affect our financial position or results of

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

operations, nor will it require any additional disclosures, but may result in a change in presentation to our consolidated balance sheets.

2. ACQUISITIONS

Acquisitions of Refineries

The acquired refining and marketing businesses discussed below involve the production and marketing of refined petroleum products. These acquisitions are consistent with our general business strategy and complement our existing refining and marketing network.

Meraux Acquisition

On October 1, 2011, we acquired the Meraux Refinery and related logistics assets from Murphy Oil Corporation for an initial payment of $586 million, which was funded from available cash. This acquisition is referred to as the Meraux Acquisition. The Meraux Refinery has a total throughput capacity of 135,000 barrels per day and is located in Meraux, Louisiana.

In the fourth quarter of 2011, we recorded an adjustment related to inventories acquired that reduced the purchase price to $547 million. In the fourth quarter of 2012, an independent appraisal of the assets acquired and liabilities assumed and certain other evaluations of the fair values related to the Meraux Acquisition were completed and finalized. The purchase price of the Meraux Acquisition was allocated based on the fair values of the assets acquired and the liabilities assumed at the date of acquisition resulting from this final appraisal and other evaluations. The primary adjustments to the preliminary purchase price allocation disclosed in 2011 consisted of an $8 million increase in materials and supplies inventories, a $27 million decrease in property, plant, and equipment, and a $19 million increase in deferred charges and other assets, net. The final amounts assigned to the assets acquired and liabilities assumed in the Meraux Acquisition were recognized at their acquisition-date fair values as follows (in millions):

Inventories	$ 227
Property, plant, and equipment	293
Deferred charges and other assets, net	28
Other long-term liabilities	(1)
Purchase price	$ 547

Pembroke Acquisition

On August 1, 2011, we acquired 100 percent of the outstanding shares of a subsidiary of Chevron Corporation (Chevron) that owned and operated the Pembroke Refinery. The refinery has a total throughput capacity of 270,000 barrels per day and is located in Wales, U.K. We also acquired an extensive network of marketing and logistics assets throughout the U.K. and Ireland as part of this acquisition. 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, we recorded an adjustment to working capital (primarily inventory), resulting in an adjusted purchase price of $1.7 billion. This acquisition is referred to as the Pembroke Acquisition.

In the third quarter of 2012, an independent appraisal of the assets acquired and liabilities assumed and certain other evaluations of the fair values related to the Pembroke Acquisition were completed and finalized.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The purchase price of the Pembroke Acquisition was allocated based on the fair values of the assets acquired and the liabilities assumed at the date of acquisition resulting from this final appraisal and other evaluations. The primary adjustments to the preliminary purchase price allocation disclosed in 2011 consisted of a $143 million increase in property, plant, and equipment, a $124 million increase in deferred income taxes, and a $17 million increase in other long-term liabilities. The final amounts assigned to the assets acquired and liabilities assumed in the Pembroke Acquisition were recognized at their acquisition-date fair values as follows (in millions):

Current assets, net of cash acquired	$2,215	
Property, plant, and equipment	947	
Intangible assets	22	
Deferred charges and other assets, net	37	
Current liabilities, less current portion of debt and capital lease obligations	(1,294	)
Debt and capital leases assumed, including current portion	(12	)
Deferred income taxes	(159	)
Other long-term liabilities	(60	)
Noncontrolling interest	(5	)
Purchase price, net of cash acquired	$1,691	

Because of the adjustment to property, plant, and equipment discussed above, we recorded an additional $6 million of depreciation expense in the third quarter of 2012 to true-up depreciation expense for the period from the date of the Pembroke Acquisition (August 1, 2011) through July 31, 2012.

In connection with the Pembroke Acquisition, 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 U.K. In the fourth quarter of 2011, we acquired the remaining 15 percent interest in MLP.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. DISPOSITIONS OF BUSINESSES

Separation of Retail Business

On May 1, 2013, we completed the separation of our retail business by creating an independent public company named CST Brands, Inc. (CST) and distributing 80 percent of the outstanding shares of CST common stock to our stockholders. Each Valero stockholder received one share of CST common stock for every nine shares of Valero common stock held at the close of business on the record date of April 19, 2013. Fractional shares of CST common stock were not distributed, but instead were aggregated and sold in the open market at prevailing rates with net cash proceeds then distributed pro rata to each Valero stockholder who was entitled to receive fractional shares.

In connection with the separation, we received an aggregate of $1.05 billion in cash, consisting of $550 million from the issuance of short-term debt to a third-party financial institution on April 16, 2013 and $500 million distributed to us by CST on May 1, 2013. The cash distributed to us by CST was borrowed by CST on May 1, 2013 under its senior secured credit facility. See Note 11 for further discussion of that credit facility. Also on May 1, 2013, CST issued $550 million of its senior unsecured bonds to us, and we exchanged those bonds with the third-party financial institution in satisfaction of our short-term debt. Immediately prior to May 1, 2013, subsidiaries of CST held $315 million of cash, and CST retained that cash following the distribution on May 1, 2013. Also in connection with the separation, we incurred a tax liability of approximately $189 million primarily related to the manner in which the transaction is treated for tax purposes in Canada; the majority of this liability was paid during 2013 and the remaining amounts will be paid in the first quarter of 2014. Therefore, the cash we received as a result of the separation, net of our tax liability, was $546 million. We also incurred $30 million in costs during the three months ended June 30, 2013 to effect the separation, which are included in general and administrative expenses.

We also entered into long-term motor fuel supply agreements with CST in the U.S. and Canada. The nature and significance of our agreements to supply motor fuel to CST through 2028 represents a continuation of activities with CST for accounting purposes. As such, the historical results of operations of our retail business have not been reported as discontinued operations in our statements of income.

On November 14, 2013, we disposed of our 20 percent retained interest in CST by transferring all remaining shares of CST common stock owned by us to a third-party financial institution in exchange for $467 million of our short-term debt and recognized a $325 million nontaxable gain, as further described in Note 11.

Selected historical results of operations of our retail business prior to the separation are disclosed in Note 18. Subsequent to May 1, 2013 and through November 14, 2013, our share of CST's results of operations is reflected in "other income, net." Our share of income taxes incurred directly by CST during this period is reported in the equity in earnings from CST, and as such is not included in income taxes in our statements of income.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the carrying values of the major categories of assets and liabilities of our retail business, immediately preceding its separation on May 1, 2013, which are excluded from our consolidated balance sheet as of December 31, 2013 (in millions):

Assets	
Cash and temporary cash investments	$315
Credit card receivables from Valero	44
Other receivables, net	109
Inventories	170
Deferred income taxes	14
Prepaid expenses and other	13
Total current assets	665
Property, plant, and equipment, at cost	1,891
Accumulated depreciation	(611)
Property, plant, and equipment, net	1,280
Intangible assets, net	38
Deferred charges and other assets, net	191
Total assets	$2,174
Liabilities	
Current portion of capital lease obligations	$2
Trade payable to Valero	242
Other accounts payable	96
Accrued expenses	31
Taxes other than income taxes	20
Total current liabilities	391
Debt and capital lease obligations, less current portion	1,053
Deferred income taxes	83
Other long-term liabilities	112
Total liabilities	$1,639

We retained certain environmental and other liabilities related to our former retail business and we have indemnified CST for certain self-insurance liabilities related to its employees and property.

Sales of Refineries

In 2010, we sold our Paulsboro and our Delaware City Refineries. The results of operations of these refineries have been presented as discontinued operations for the year ended December 31, 2011.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. IMPAIRMENTS

Benicia Refinery
We evaluated the Benicia Refinery for potential impairment as of December 31, 2013 due to its actual operating and cash flow results during 2013 and its forecasted results over the next five years. We developed cash flows expected to be generated by the refinery, considering the probability of both current disposition of the refinery and realization through operations, using various scenarios of forecasted throughput volumes and refined product margins, with refined product margins based on our expectation of future margins coupled with historical margins realized by the refinery. The undiscounted cash flows exceeded the carrying amount of the refinery as of December 31, 2013; therefore, we concluded that the refinery was not impaired.

Aruba Refinery
In March 2012, we suspended the operations of the Aruba Refinery because of its inability to generate positive cash flows on a sustained basis subsequent to its restart in January 2011 and the sensitivity of its profitability to sour crude oil differentials, which had narrowed significantly in the fourth quarter of 2011. Shortly thereafter, we received a non-binding offer to purchase the refinery for $350 million, plus working capital as of the closing date. Because of our decision to suspend operations and the possibility of selling the refinery, we evaluated the refinery for potential impairment as of March 31, 2012 and concluded that it was impaired. We recognized an asset impairment loss of $595 million in March 2012. We did not, however, classify the Aruba Refinery as “held for sale” in our balance sheet because all of the accounting criteria required for that classification had not been met.

In September 2012, we decided to reorganize the Aruba Refinery into a crude oil and refined products terminal in response to the withdrawal of the non-binding offer to purchase the refinery. We bifurcated the idled crude oil processing units and related infrastructure (refining assets) from the terminal assets and evaluated the refining assets for potential impairment as of September 30, 2012. We concluded that the refining assets were impaired and recognized an asset impairment loss of $308 million that was recorded in September 2012. We also recognized an asset impairment loss of $25 million related to materials and supplies inventories that supported the refining operations, resulting in a total asset impairment loss of $333 million in September 2012 related to the Aruba Refinery. The terminal assets were not impaired.

We have continued to maintain the refining assets to allow them to be restarted and do not consider them to be abandoned. Therefore, we have not reflected the Aruba Refinery as a discontinued operation in our financial statements. It is possible, however, that we may abandon these assets in the future. Should we ultimately decide to abandon these assets, we may be required under our land lease agreement with the Government of Aruba to dismantle and remove the abandoned assets, which would require us to recognize an asset retirement obligation that would be immediately charged to expense. We do not expect these amounts to be material to our financial position or results of operations.

Cancelled Capital Projects
During 2012, we wrote down the carrying value of equipment associated with permanently cancelled capital projects at several of our refineries and recognized asset impairment losses of $65 million.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Retail Stores

During 2012, we evaluated certain of our convenience stores operated by our former retail segment for potential impairment and concluded that they were impaired, and we wrote down the carrying values of these stores to their estimated fair values and recognized asset impairment losses of $21 million.

5. INITIAL PUBLIC OFFERING OF VALERO ENERGY PARTNERS LP

In July 2013, we formed VLP, a master limited partnership, to own, operate, develop, and acquire crude oil and refined petroleum products pipelines, terminals, and other transportation and logistics assets. On December 16, 2013, VLP completed its initial public offering (the Offering) of 17,250,000 common units at a price of $23.00 per unit, which included a 2,250,000 common unit over-allotment option that was fully exercised by the underwriters. VLP received $369 million in net proceeds from the sale of the units, after deducting underwriting fees, structuring fees, and other offering costs. VLP’s assets include crude oil and refined petroleum products pipeline and terminal systems in the U.S Gulf Coast and U.S. Mid-Continent regions that are integral to the operations of our Port Arthur, McKee and Memphis Refineries.

As of December 31, 2013, we owned a 68.6 percent limited partner interest and a 2 percent general partner interest in VLP, and the public owned a 29.4 percent limited partner interest. VLP’s cash and temporary cash investments was $375 million as of December 31, 2013, which can be used only to settle its obligations. The public’s ownership interest in VLP of $370 million is reflected in noncontrolling interests as of December 31, 2013.

The following table is a reconciliation of net proceeds from the Offering (in millions):

Total proceeds from the Offering	$397
Less offering costs	(28)
Net proceeds from the Offering	$369

We have agreements with VLP, which establish fees for certain general and administrative services, and operational and maintenance services provided by us. In addition, we have a master transportation services agreement and a master terminal services agreement with VLP where VLP provides commercial transportation and terminaling services to us. These transactions are eliminated in consolidation.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. RECEIVABLES

Receivables consisted of the following (in millions):

	December 31,	
	2013	2012
Accounts receivable	$8,650	$8,061
Commodity derivative and foreign currency contract receivables	98	136
Notes receivable and other	49	26
	8,797	8,223
Allowance for doubtful accounts	(46)	(56)
Receivables, net	$8,751	$8,167

Changes in the allowance for doubtful accounts consisted of the following (in millions):

	Year Ended December 31,		
	2013	2012	2011
Balance as of beginning of year	$56	$48	$42
Increase in allowance charged to expense	13	21	21
Accounts charged against the allowance, net of recoveries	(23)	(13)	(14)
Foreign currency translation	—	—	(1)
Balance as of end of year	$46	$56	$48

7. INVENTORIES

Inventories consisted of the following (in millions):

	December 31,	
	2013	2012
Refinery feedstocks	$2,135	$2,458
Refined products and blendstocks	3,231	2,995
Ethanol feedstocks and products	166	191
Convenience store merchandise	—	112
Materials and supplies	226	217
Inventories	$5,758	$5,973

During the years ended December 31, 2013, 2012, and 2011, we had net liquidations of LIFO inventory layers that were established in prior years, which decreased cost of sales in each of those years by $17 million, $134 million, and $247 million, respectively.

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As of December 31, 2013 and 2012, the replacement cost (market value) of LIFO inventories exceeded their LIFO carrying amounts by approximately $6.9 billion and $6.7 billion, respectively. As of December 31, 2013 and 2012, our non-LIFO inventories accounted for $851 million and $878 million, respectively, of our total inventories.

8. PROPERTY, PLANT, AND EQUIPMENT

Major classes of property, plant, and equipment, which include capital lease assets, consisted of the following (in millions):

	December 31,	
	2013	2012
Land	$404	$802
Crude oil processing facilities	27,260	24,865
Pipeline and terminal facilities	1,513	1,471
Grain processing equipment	719	694
Retail facilities	—	1,480
Administrative buildings	800	734
Other	2,109	1,457
Construction in progress	1,128	2,629
Property, plant, and equipment, at cost	33,933	34,132
Accumulated depreciation	(8,226)	(7,832)
Property, plant, and equipment, net	$25,707	$26,300

We have miscellaneous assets under capital leases that primarily support our refining operations totaling $74 million and $83 million as of December 31, 2013 and 2012, respectively. Accumulated amortization on assets under capital leases was $35 million and $35 million, respectively, as of December 31, 2013 and 2012.

Depreciation expense for the years ended December 31, 2013, 2012, and 2011 was $1.2 billion, $1.1 billion, and $1.1 billion, respectively.

9. DEFERRED CHARGES AND OTHER ASSETS

"Deferred charges and other assets, net" primarily includes turnaround and catalyst costs, which are deferred and amortized as discussed in Note 1. Amortization expense for deferred refinery turnaround and catalyst costs and other assets was $498 million, $459 million, and $444 million for the years ended December 31, 2013, 2012, and 2011, respectively.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. ACCRUED EXPENSES AND OTHER LONG-TERM LIABILITIES

Accrued expenses and other long-term liabilities consisted of the following (in millions):

	Accrued Expenses		Other Long-Term Liabilities	
	December 31,			
	2013	2012	2013	2012
Defined benefit plan liabilities (see Note 14)	$30	$32	$507	$982
Wage and other employee-related liabilities	257	282	97	91
Uncertain income tax position liabilities, including related penalties and interest (see Note 16) [a]	—	—	205	391
Environmental liabilities	24	27	277	242
Accrued interest expense	90	96	—	—
Derivative liabilities	13	14	—	—
Asset retirement obligations	5	5	26	103
Other accrued liabilities	103	134	217	321
Accrued expenses and other long-term liabilities	$522	$590	$1,329	$2,130

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[a] As of December 31, 2013, our total liability for uncertain tax positions, including related penalties and interest, was $443 million, with $238 million classified as a current liability and reflected in "Income taxes payable" and the remaining $205 million classified as a long-term liability and reflected in "Other long-term liabilities" as detailed in this table. As of December 31, 2012, our total liability for uncertain tax positions, including related penalties and interest, was classified as a long-term liability and reflected in "Other long-term liabilities" as detailed in this table.

Environmental Liabilities

Changes in our environmental liabilities were as follows (in millions):

	Year Ended December 31,		
	2013	2012	2011
Balance as of beginning of year	$269	$274	$268
Pembroke Acquisition	—	—	30
Additions to liability	67	23	18
Reductions to liability	(1)	(1)	(5)
Payments, net of third-party recoveries	(28)	(29)	(35)
Separation of retail business	(4)	—	—
Foreign currency translation	(2)	2	(2)
Balance as of end of year	$301	$269	$274

In connection with our Pembroke Acquisition, we assumed certain environmental liabilities including, but not limited to, certain remediation obligations, site restoration costs, and certain liabilities relating to soil and groundwater remediation. There were no significant environmental liabilities assumed in connection with the Meraux Acquisition. See Note 12 for further information regarding environmental matters.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Asset Retirement Obligations

We have asset retirement obligations with respect to certain of our refinery assets due to various legal obligations to clean and/or dispose of various component parts of each refinery at the time they are retired. However, these component parts can be used for extended and indeterminate periods of time as long as they are properly maintained and/or upgraded. It is our practice and current intent to maintain our refinery assets and continue making improvements to those assets based on technological advances. As a result, we believe that our refineries have indeterminate lives for purposes of estimating asset retirement obligations because dates or ranges of dates upon which we would retire refinery assets cannot reasonably be estimated at this time. When a date or range of dates can reasonably be estimated for the retirement of any component part of a refinery, we estimate the cost of performing the retirement activities and record a liability for the fair value of that cost using established present value techniques.

Prior to the separation of our retail business, we also had asset retirement obligations for the removal of underground storage tanks (USTs) at owned and leased retail sites. There is no legal obligation to remove USTs while they remain in service. However, environmental laws in the U.S. and Canada require that unused USTs be removed within certain periods of time after the USTs are no longer in service, usually one to two years depending on the jurisdiction in which the USTs are located. We had previously estimated that USTs at our formerly owned retail sites would remain in service approximately 20 years and that we would then have an obligation to remove those USTs. For our formerly leased retail sites, our lease agreements generally required that we remove certain improvements, primarily USTs and signage, upon termination of the lease. All of the USTs and the related asset retirement obligations were retained by CST after the separation from us. Therefore, we have no asset retirement obligations in connection with the USTs subsequent to the separation of our retail business on May 1, 2013.

Changes in our asset retirement obligations were as follows (in millions).

	Year Ended December 31,		
	2013	2012	2011
Balance as of beginning of year	$108	$87	$101
Additions to accrual	2	14	3
Revisions in estimated cash flows	—	13	1
Accretion expense	2	5	4
Settlements	(1)	(11)	(22)
Separation of retail business	(80)	—	—
Balance as of end of year	$31	$108	$87

There are no assets that are legally restricted for purposes of settling our asset retirement obligations.

One-Time Severance Benefits

As described in Note 4, we decided to reorganize the Aruba Refinery into a crude oil and refined products terminal in September 2012 resulting in a decrease in required personnel for our operations in Aruba. We notified 495 employees in September 2012 of the termination of their employment effective November 15, 2012. Benefits to each terminated employee consisted primarily of a cash payment based on a formula that

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

considered the employee’s current compensation and years of service, among other factors. We recognized a severance liability of $41 million in September 2012, which approximated fair value. We paid $31 million of these benefits in the fourth quarter of 2012. We paid the remaining termination benefits of $10 million in the first quarter of 2013. Total severance expense of $41 million is included in refining operating expenses for the year ended December 31, 2012 and relates to our refining segment.

11. DEBT AND CAPITAL LEASE OBLIGATIONS

Debt, at stated values, and capital lease obligations consisted of the following (in millions):

	Final	December 31,	
	Maturity	2013	2012
Bank credit facilities	Various	$—	$—
Senior Notes:			
4.5%	2015	400	400
4.75%	2013	—	300
4.75%	2014	200	200
6.125%	2017	750	750
6.125%	2020	850	850
6.625%	2037	1,500	1,500
6.7%	2013	—	180
6.75%	2037	24	24
7.2%	2017	200	200
7.45%	2097	100	100
7.5%	2032	750	750
8.75%	2030	200	200
9.375%	2019	750	750
10.5%	2039	250	250
Debentures:			
7.65%	2026	100	100
8.75%	2015	75	75
Gulf Opportunity Zone Revenue Bonds, Series 2010, 4.0%	2040	300	300
Accounts receivable sales facility	2014	100	100
Net unamortized discount, including fair value adjustments		(24)	(29)
Total debt		6,525	7,000
Capital lease obligations, including unamortized fair value adjustments		39	49
Total debt and capital lease obligations		6,564	7,049
Less current portion		(303)	(586)
Debt and capital lease obligations, less current portion		$6,261	$6,463

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Credit Facilities

Revolver

We have a $3 billion revolving credit facility (the Revolver) with a group of financial institution lenders that has a maturity date of November 2018. We have the option to increase the aggregate commitments under the Revolver to $4.5 billion, subject to, among other things, the consent of the existing lenders whose commitments will be increased or any additional lenders providing such additional capacity. We may request additional one-year extensions, subject to certain conditions, including the consent of the lenders holding the majority of the commitments and each lender extending its individual commitment. The Revolver includes sub-facilities for swingline loans and letters of credit. Outstanding borrowings under the Revolver bear interest, at our option, at either (a) the adjusted LIBO rate (as defined in the Revolver) for the applicable interest period in effect from time to time plus the applicable margin or (b) the alternate base rate (as defined in the Revolver) plus the applicable margin. The interest rate and fees under the Revolver are subject to adjustment based upon the credit ratings assigned to our senior unsecured debt. We are also charged various fees and expenses in connection with the Revolver, including facility fees and letter of credit fees. The Revolver has certain restrictive covenants, including a maximum debt-to-capitalization ratio of 60 percent. As of December 31, 2013 and 2012, our debt-to-capitalization ratios, calculated in accordance with the terms of the Revolver, were 12 percent and 23 percent, respectively. We believe that we will remain in compliance with this covenant.

VLP Revolver

On November 14, 2013, VLP entered into a $300 million senior unsecured revolving credit facility agreement (the VLP Revolver) with a group of lenders. The VLP Revolver is available only to the operations of VLP, and creditors of VLP do not have recourse against Valero. VLP has the option to increase the aggregate commitments under the VLP Revolver to $500 million, subject to, among other things, the consent of the existing lenders whose commitments will be increased or any additional lenders providing such additional capacity. The VLP Revolver has a maturity date of December 2018 and VLP may request two additional one-year extensions, subject to certain conditions. VLP may terminate the VLP Revolver with notice to the lenders of at least three business days prior to termination. The VLP Revolver includes sub-facilities for swingline loans and letters of credit. VLP’s obligations under the VLP Revolver will be jointly and severally guaranteed by all of VLP’s directly owned material subsidiaries. As of December 31, 2013, the only guarantor under the VLP Revolver was Valero Partners Operating Co. LLC.

Outstanding borrowings under the VLP Revolver bear interest, at VLP’s option, at either (a) the adjusted LIBO rate (as described in the VLP Revolver) for the applicable interest period in effect from time to time plus the applicable margin or (b) the alternate base rate (as described in the VLP Revolver) plus the applicable margin. The VLP Revolver also provides for customary fees, including administrative agent fees, participation fees, and commitment fees. The VLP Revolver contains certain restrictive covenants, including a ratio of total debt to EBITDA (as defined in the VLP Revolver) for the prior four fiscal quarters of not greater than 5.0 to 1.0 as of the last day of each fiscal quarter, and limitations on VLP’s ability to pay distributions to its unitholders.

Canadian Facility

In addition to the Revolver and the VLP Revolver, one of our Canadian subsidiaries has a C$50 million committed revolving credit facility under which it may borrow and obtain letters of credit that has a maturity

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date of November 2014. This facility replaced the maturing C$115 million Canadian revolving credit facility in November 2012.

Activities of Our Credit Facilities

During the years ended December 31, 2013 and 2011, we had no borrowings or repayments under the Revolver, the VLP Revolver, or under our Canadian credit facility. During the year ended December 31, 2012, we borrowed and repaid $1.1 billion under the Revolver and had no borrowings or repayments under the Canadian credit facility.

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

			Amounts Outstanding	
	Borrowing Capacity	Expiration	December 31, 2013	December 31, 2012
Letter of credit facilities	$ 550	June 2014	$ 278	$ 418
Revolver	$ 3,000	November 2018	$ 59	$ 59
Canadian revolving credit facility	C$50	November 2014	C$10	C$10

We also have various other uncommitted short-term bank credit facilities. As of December 31, 2013 and 2012, we had no borrowings outstanding under our uncommitted short-term bank credit facilities; however, there were letters of credit outstanding under such facilities of $189 million and $275 million, respectively, for which we are charged letter of credit issuance fees. The uncommitted credit facilities have no commitment fees or compensating balance requirements.

Bank Debt

On March 20, 2013, in anticipation of the separation of our retail business as described in Note 3, CST entered into an $800 million senior secured credit agreement. This credit agreement was retained by CST after the separation from us. Therefore, we have no rights to obtain credit under nor any liabilities in connection with this credit agreement.

On April 16, 2013, also in anticipation of the separation of our retail business, we borrowed $550 million under a short-term debt agreement with a third-party financial institution. On May 1, 2013, CST issued $550 million of its senior unsecured bonds to us, and we exchanged those bonds with the third-party financial institution in satisfaction of our short-term debt.

On October 24, 2013, we borrowed $525 million under a short-term debt agreement with a third-party financial institution in anticipation of liquidating our retained interest in CST. This liquidation was completed on November 14, 2013 by transferring all remaining shares of CST common stock owned by us to the financial institution in exchange for $467 million of our short-term debt, and we paid the remaining $58 million of short-term debt in cash. After paying $19 million of fees, we recognized a $325 million nontaxable gain.

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Non-Bank Debt

During the year ended December 31, 2013, the following activity occurred:

- in January 2013, we made a scheduled debt repayment of $180 million related to our 6.7% senior notes; and
- in June 2013, we made a scheduled debt repayment of $300 million related to our 4.75% senior notes.

During the year ended December 31, 2012, the following activity occurred:

- in March 2012, we exercised the call provisions on our Series 1997 5.6%, Series 1998 5.6%, Series 1999 5.7%, Series 2001 6.65%, and Series 1997A 5.45% industrial revenue bonds, which were redeemed on May 3, 2012 for $108 million, or 100% of their outstanding stated values;
- in April 2012, we made scheduled debt repayments of $4 million related to our Series 1997A 5.45% industrial revenue bonds and $750 million related to our 6.875% notes; and
- in June 2012, we remarketed and received proceeds of $300 million related to the 4.0% Gulf Opportunity Zone Revenue Bonds Series 2010 issued by the Parish of St. Charles, State of Louisiana (GO Zone Bonds), which are due December 1, 2040, but are subject to mandatory tender on June 1, 2022.

During the year ended December 31, 2011, the following activity occurred:

- in February 2011, we paid $300 million to acquire the GO Zone Bonds, which had originally been issued in December 2010. These bonds were remarketed in June 2012, as previously discussed;
- in February 2011, we made a scheduled debt repayment of $210 million related to our 6.75% senior notes;
- in April 2011, we made scheduled debt repayments of $8 million related to our Series 1997A 5.45%, Series 1997B 5.4%, and Series 1997C 5.4% industrial revenue bonds;
- in May 2011, we made a scheduled debt repayment of $200 million related to our 6.125% senior notes; and
- in December 2011, we redeemed our Series 1997B 5.4% and Series 1997C 5.4% industrial revenue bonds for $56 million, or 100% of their stated values.

Accounts Receivable Sales Facility

We have an accounts receivable sales facility with a group of third-party entities and financial institutions to sell up to $1.5 billion of eligible trade receivables on a revolving basis. In July 2013, we amended this facility to extend the maturity date to July 2014. Under this program, one of our marketing subsidiaries (Valero Marketing) sells eligible receivables, without recourse, to another of our subsidiaries (Valero Capital), whereupon the receivables are no longer owned by Valero Marketing. Valero Capital, in turn, sells an undivided percentage ownership interest in the eligible receivables, without recourse, to the third-party entities and financial institutions. To the extent that Valero Capital retains an ownership interest in the receivables it has purchased from Valero Marketing, such interest is included in our financial statements solely as a result of the consolidation of the financial statements of Valero Capital with those of Valero Energy Corporation; the receivables are not available to satisfy the claims of the creditors of Valero Marketing or Valero Energy Corporation.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2013 and 2012, $3.3 billion and $3.2 billion, respectively, of our accounts receivable composed the designated pool of accounts receivable included in the program. All amounts outstanding under the accounts receivable sales facility are reflected as debt on our balance sheets and proceeds and repayments are reflected as cash flows from financing activities on the statements of cash flows. Changes in the amounts outstanding under our accounts receivable sales facility were as follows (in millions):

	Year Ended December 31,		
	2013	2012	2011
Balance as of beginning of year	$100	$250	$100
Proceeds from the sale of receivables	—	1,500	150
Repayments	—	(1,650)	—
Balance as of end of year	$100	$100	$250

Capitalized Interest
For the years ended December 31, 2013, 2012, and 2011, capitalized interest was $118 million, $221 million, and $152 million, respectively.

Other Disclosures
In addition to the maximum debt-to-capitalization ratio applicable to the Revolver discussed above under “Bank Credit Facilities,” our bank credit facilities and other debt arrangements contain various customary restrictive covenants, including cross-default and cross-acceleration clauses.
Principal payments on our debt obligations and future minimum rentals on capital lease obligations as of December 31, 2013 were as follows (in millions):

	Debt	Capital Lease Obligations
2014	$300	$8
2015	475	8
2016	—	7
2017	950	7
2018	—	6
Thereafter	4,824	27
Net unamortized discount and fair value adjustments	(24)	1
Less interest expense	—	(25)
Total	$6,525	$39

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. COMMITMENTS AND CONTINGENCIES

Operating Leases

We have long-term operating lease commitments for land, office facilities and equipment, transportation equipment, time charters for ocean-going tankers and coastal vessels, dock facilities, and various facilities and equipment used in the storage, transportation, production, and sale of refinery feedstocks, refined product and corn inventories.

Certain leases for processing equipment and feedstock and refined product storage facilities provide for various contingent payments based on, among other things, throughput volumes in excess of a base amount. Certain leases for vessels contain renewal options and escalation clauses, which vary by charter, and provisions for the payment of chartering fees, which either vary based on usage or provide for payments, in addition to established minimums, that are contingent on usage. In most cases, we expect that in the normal course of business, our leases will be renewed or replaced by other leases.

As of December 31, 2013, our future minimum rentals and minimum rentals to be received under subleases for leases having initial or remaining noncancelable lease terms in excess of one year were as follows (in millions):

2014	$305
2015	230
2016	162
2017	111
2018	95
Thereafter	321
Total minimum rental payments	$1,224
Minimum rentals to be received under subleases	$21

Rental expense was as follows (in millions):

	Year Ended December 31,		
	2013	2012	2011
Minimum rental expense	$574	$508	$523
Contingent rental expense	7	23	23
Total rental expense	581	531	546
Less sublease rental income	—	(2)	(2)
Net rental expense	$581	$529	$544

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Purchase Obligations
We have various purchase obligations under certain industrial gas and chemical supply arrangements (such as hydrogen supply arrangements), crude oil and other feedstock supply arrangements, and various throughput and terminalling agreements. We enter into these contracts to ensure an adequate supply of utilities and feedstock and adequate storage capacity to operate our refineries. Substantially all of our purchase obligations are based on market prices or adjustments based on market indices. Certain of these purchase obligations include fixed or minimum volume requirements, while others are based on our usage requirements. None of these obligations are associated with suppliers’ financing arrangements. These purchase obligations are not reflected as liabilities.

Environmental Matters
Hartford Matters
We are involved, together with several other companies, in an environmental cleanup in the Village of Hartford, Illinois (the Village) and the adjacent shutdown refinery site, which we acquired as part of a prior acquisition. In cooperation with some of the other companies, we have been conducting initial mitigation and cleanup response pursuant to an administrative order issued by the U.S. Environmental Protection Agency (EPA). The EPA is seeking further cleanup obligations from us and other potentially responsible parties for the Village. In parallel with the Village cleanup, we are also in litigation with the State of Illinois Environmental Protection Agency and other potentially responsible parties relating to the remediation of the shutdown refinery site. In each of these matters, we have various defenses and rights for contribution from the other responsible parties. We have accrued for our own expected contribution obligations. However, because of the unpredictable nature of these cleanups and the methodology for allocation of liabilities, it is reasonably possible that we could incur a loss in a range of $0 to $200 million in excess of the amount of our accrual to ultimately resolve these matters. Factors underlying this estimated range are expected to change from time to time, and actual results may vary significantly from this estimate.

Regulation of Greenhouse Gases
The EPA began regulating greenhouse gases on January 2, 2011, under the Clean Air Act Amendments of 1990 (Clean Air Act). 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 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 would be on a case by case basis, and the EPA has provided only general guidance for which controls will be required or delegated to the states through State Implementation Plans.

Furthermore, the EPA is currently developing refinery-specific greenhouse gas regulations and performance standards that are expected to impose, on new and modified operations, greenhouse gas emission limits and/or technology requirements. These control requirements may affect a wide range of refinery operations but have not yet been delineated. 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.

Certain states and foreign governments have pursued regulation of greenhouse gases independent of the EPA. 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 currently subject to legal challenges in both state and federal court. The program currently is in effect, but the progressive reductions in the carbon intensity of fuel required under the LCFS currently are frozen at 2013 levels by order of a California state court until the CARB addresses certain deficiencies under the California Environmental Quality Act. Meanwhile, the Ninth Circuit Court of Appeals recently reversed a lower-court finding that the LCFS violates the Commerce Clause of the U.S. Constitution. It is anticipated that this case will be appealed to the U.S. Supreme Court, although it remains unclear whether the U.S. Supreme Court will agree to review the case.
- The California statewide cap-and-trade program became effective in 2012, with the auctioning of emission credits commencing in the fourth quarter of 2012. Initially, the program will apply only to stationary sources of greenhouse gases (e.g., refinery and power plant greenhouse gas emissions). Greenhouse gas emissions from fuels that we sell in California will be covered by the program beginning in 2015. We anticipate that free allocations of credits will be available in the early years of the program, but we expect that compliance costs will escalate as free allocations compromise a smaller portion of the progressive compliance obligation. Further, overall cap-and-trade program costs are expected to increase significantly beginning in 2015, when transportation 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.

Title V Permitting Matters

The EPA has objected to numerous Title V permits, including permits at our Port Arthur, Texas City, Meraux, Corpus Christi East, and McKee Refineries. Environmental activist groups have filed notices of intent to sue and/or sued the EPA, seeking to require the EPA to assume control of these permits from the Texas Commission on Environmental Quality. 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. The greenhouse gas permitting regime and the EPA’s objections to Title V permits 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.

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

VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, results of operations, or liquidity.

Tax Matters

General

We are subject to extensive tax liabilities imposed by multiple jurisdictions, including income taxes, indirect taxes (excise/duty, sales/use, gross receipts, and value-added taxes), payroll taxes, franchise taxes, withholding taxes, 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.

IRS Audits

As of December 31, 2013, the Internal Revenue Service (IRS) has ongoing tax audits related to our U.S. federal tax returns from 2002 through 2011, as discussed in Note 16. We have received Revenue Agent Reports on our tax years for 2002 through 2009 and we are vigorously contesting many of the tax positions and assertions from the IRS. We are continuing to work with the IRS to resolve these matters and we believe that they will be resolved for amounts consistent with the recorded amounts of unrecognized tax benefits associated with these matters.

Self-Insurance

We are self-insured for certain medical and dental, workers’ compensation, automobile liability, general liability, and property liability claims up to applicable retention limits. Liabilities are accrued for self-insured claims, or when estimated losses exceed coverage limits, and when sufficient information is available to reasonably estimate the amount of the loss. These liabilities are included in accrued expenses and other long-term liabilities.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. EQUITY

Share Activity

For the years ended December 31, 2013, 2012, and 2011, activity in the number of shares of common stock and treasury stock was as follows (in millions):

	Common Stock	Treasury Stock
Balance as of December 31, 2010	673	(105)
Transactions in connection with stock-based compensation plans:		
Stock issuances	—	5
Stock repurchases	—	(17)
Balance as of December 31, 2011	673	(117)
Transactions in connection with stock-based compensation plans:		
Stock issuances	—	6
Stock repurchases	—	(6)
Stock repurchases under buyback program	—	(4)
Balance as of December 31, 2012	673	(121)
Transactions in connection with stock-based compensation plans:		
Stock issuances	—	6
Stock repurchases	—	(6)
Stock repurchases under buyback program	—	(17)
Balance as of December 31, 2013	673	(138)

Preferred Stock

We have 20 million shares of preferred stock authorized with a par value of $0.01 per share. No shares of preferred stock were outstanding as of December 31, 2013 and 2012.

Treasury Stock

We purchase shares of our common stock in open market transactions to meet our obligations under employee stock-based compensation plans. We also purchase shares of our common stock 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.

On February 28, 2008, our board of directors approved a $3 billion common stock purchase program, which is in addition to the remaining amount under a $6 billion program previously authorized. This additional $3 billion program has no expiration date. During 2013, we completed the $6 billion program. During the years ended December 31, 2013 and 2012, we purchased $692 million and $118 million, respectively, of

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

our common stock under our programs. There were no stock repurchases under the buyback program during the year ended December 31, 2011. As of December 31, 2013, we have approvals under the $3 billion program to purchase approximately $2.6 billion of our common stock. In January 2014, we purchased 4 million shares for $208 million.

Common Stock Dividends

On January 22, 2014, our board of directors declared a quarterly cash dividend of $0.25 per common share payable March 12, 2014 to holders of record at the close of business on February 12, 2014.

Income Tax Effects Related to Components of Other Comprehensive Income

The following table reflects the tax effects allocated to each component of other comprehensive income for the years ended December 31, 2013, 2012, and 2011 (in millions):

	Before-Tax Amount	Tax Expense (Benefit)	Net Amount
Year Ended December 31, 2013:			
Foreign currency translation adjustment	$(98)	$—	$(98)
Pension and other postretirement benefits:			
Gain arising during the year related to:			
Net actuarial gain	367	125	242
Plan amendments	371	130	241
(Gain) loss reclassified into income related to:			
Net actuarial loss	57	20	37
Prior service credit	(33)	(12)	(21)
Settlement	1	—	1
Net gain on pension and other postretirement benefits	763	263	500
Derivative instruments designated and qualifying as cash flow hedges:			
Net loss arising during the year	(4)	(2)	(2)
Net loss reclassified into income	2	1	1
Net loss on cash flow hedges	(2)	(1)	(1)
Other comprehensive income	$663	$262	$401

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Before-Tax Amount	Tax Expense (Benefit)	Net Amount
Year Ended December 31, 2012:			
Foreign currency translation adjustment	$164	$—	$164
Pension and other postretirement benefits:			
Loss arising during the year related to:			
Net actuarial loss	(228)	(79)	(149)
Prior service cost	(9)	(3)	(6)
(Gain) loss reclassified into income related to:			
Net actuarial loss	34	12	22
Prior service credit	(20)	(7)	(13)
Settlement	12	—	12
Net loss on pension and other postretirement benefits	(211)	(77)	(134)
Derivative instruments designated and qualifying as cash flow hedges:			
Net gain arising during the year	45	16	29
Net gain reclassified into income	(73)	(26)	(47)
Net loss on cash flow hedges	(28)	(10)	(18)
Other comprehensive income (loss)	$(75)	$(87)	$12
Year Ended December 31, 2011:			
Foreign currency translation adjustment	$(122)	$—	$(122)
Pension and other postretirement benefits:			
Loss arising during the year related to:			
Net actuarial loss	(285)	(100)	(185)
Prior service cost	(4)	(1)	(3)
(Gain) loss reclassified into income related to:			
Net actuarial loss	14	4	10
Prior service credit	(21)	(7)	(14)
Settlement	4	1	3
Net loss on pension and other postretirement benefits	(292)	(103)	(189)
Derivative instruments designated and qualifying as cash flow hedges:			
Net gain arising during the year	32	11	21
Net gain reclassified into income	(3)	(1)	(2)
Net gain on cash flow hedges	29	10	19
Other comprehensive loss	$(385)	$(93)	$(292)

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accumulated Other Comprehensive Income
Changes in accumulated other comprehensive income by component, net of tax, were as follows (in millions):

	Foreign Currency Translation Adjustment	Defined Benefit Pension Items	Gains and (Losses) on Cash Flow Hedges	Total
Balance as of December 31, 2010	$623	$(235)	$—	$388
Other comprehensive income (loss)	(122)	(189)	19	(292)
Balance as of December 31, 2011	501	(424)	19	96
Other comprehensive income (loss)	164	(134)	(18)	12
Balance as of December 31, 2012	665	(558)	1	108
Other comprehensive income (loss) before reclassifications	(98)	483	(2)	383
Amounts reclassified from accumulated other comprehensive income (loss)	—	17	1	18
Net other comprehensive income (loss)	(98)	500	(1)	401
Separation of retail business	(159)	—	—	(159)
Balance as of December 31, 2013	$408	$(58)	$—	$350

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gains (losses) reclassified out of accumulated other comprehensive income (loss) and into net income were as follows (in millions):

Details about Accumulated Other Comprehensive Income (Loss) Components	Year Ended December 31, 2013		Affected Line Item in the Statement of Income
Amortization of items related to defined benefit pension plans:			
Net actuarial loss	$(57	)	(a)
Prior service credit	33		(a)
Settlement	(1	)	(a)
	(25	)	Total before tax
	8		Tax benefit
	$(17	)	Net of tax
Losses on cash flow hedges:			
Commodity contracts	$(2	)	Cost of sales
	(2	)	Total before tax
	1		Tax benefit
	$(1	)	Net of tax
Total reclassifications for the year	$(18	)	Net of tax

(a) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost, as further discussed in Note 14. Net periodic benefit cost is reflected in operating expenses and general and administrative expenses.

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14 . EMPLOYEE BENEFIT PLANS

Defined Benefit Plans

We have defined benefit pension plans, some of which are subject to collective bargaining agreements, that cover most of our employees. These plans provide eligible employees with retirement income based primarily on years of service and compensation during specific periods under final average pay and cash balance formulas. We fund our pension plans as required by local regulations. In the U.S., all qualified pension plans are subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. We typically do not fund or fully fund U.S. nonqualified and certain international pension plans that are not subject to funding requirements because contributions to these pension plans may be less economic and investment returns may be less attractive than our other investment alternatives.

In February 2013, we announced changes to certain of our U.S. qualified pension plans that cover the majority of our U.S. employees who work in our refining segment and corporate operations. Benefits under our primary pension plan changed from a final average pay formula to a cash balance formula with staged effective dates that commence either on July 1, 2013 or January 1, 2015 depending on the age and service of the affected employees. All final average pay benefits will be frozen as of December 31, 2014, with all future benefits to be earned under the new cash balance formula. These plan amendments resulted in a $328 million decrease to pension liabilities and a related increase to other comprehensive income during the year ended December 31, 2013. The benefit of this remeasurement will be amortized into income through 2025.

We also provide health care and life insurance benefits for certain retired employees through our postretirement benefit plans. Most of our employees become eligible for these benefits if, while still working for us, they reach normal retirement age or take early retirement. These plans are unfunded, and retired employees share the cost with us. Individuals who became our employees as a result of an acquisition became eligible for other postretirement benefits under our plans as determined by the terms of the relevant acquisition agreement.

In October 2013, we announced changes to our U.S. retiree health care plans to utilize more efficient insurance products for Medicare eligible retirees. These plan changes resulted in a $43 million decrease to our benefit obligations for other postretirement benefit plans and a related increase to other comprehensive income during the year ended December 31, 2013.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The changes in benefit obligation related to all of our defined benefit plans, the changes in fair value of plan assets[(a)], and the funded status of our defined benefit plans as of and for the years ended were as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2013	2012	2013	2012
Changes in benefit obligation:				
Benefit obligation as of beginning of year	$2,307	$1,881	$436	$438
Service cost	137	140	12	12
Interest cost	86	93	18	21
Participant contributions	—	—	15	14
Plan amendments	(274)	9	(43)	—
Curtailment gain	(6)	(16)	—	—
Benefits paid	(170)	(90)	(37)	(35)
Actuarial (gain) loss	(169)	289	(77)	(17)
Other	3	1	—	3
Benefit obligation as of end of year	$1,914	$2,307	$324	$436
Changes in plan assets[(a)]:				
Fair value of plan assets as of beginning of year	$1,729	$1,487	$—	$—
Actual return on plan assets	306	167	—	—
Valero contributions	41	164	19	19
Participant contributions	—	—	15	14
Benefits paid	(170)	(90)	(37)	(35)
Other	3	1	3	2
Fair value of plan assets as of end of year	$1,909	$1,729	$—	$—
Reconciliation of funded status[(a)]:				
Fair value of plan assets as of end of year	$1,909	$1,729	$—	$—
Less benefit obligation as of end of year	1,914	2,307	324	436
Funded status as of end of year	$(5)	$(578)	$(324)	$(436)
Accumulated benefit obligation	$1,811	$1,857	n/a	n/a

(a) Plan assets include only the assets associated with pension plans subject to legal minimum funding standards. Plan assets associated with U.S. nonqualified pension plans are not included here because they are not protected from our creditors and therefore cannot be reflected as a reduction from our obligations under the pension plans. As a result, the reconciliation of funded status does not reflect the effect of plan assets that exist for all of our defined benefit plans. See Note 20 for the assets associated with certain U.S. nonqualified pension plans.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amounts recognized in our balance sheet for our pension and other postretirement benefits plans as of December 31, 2013 and 2012 include (in millions):

	Pension Plans		Other Postretirement Benefit Plans	
	2013	2012	2013	2012
Deferred charges and other assets, net	$208	$—	$—	$—
Accrued expenses	(11)	(11)	(19)	(21)
Other long-term liabilities	(202)	(567)	(305)	(415)
	$(5)	$(578)	$(324)	$(436)

The accumulated benefit obligations for certain of our pension plans exceed the fair values of the assets of those plans. For those plans, the table below presents the total projected benefit obligation, accumulated benefit obligation, and fair value of the plan assets (in millions).

	December 31,	
	2013	2012
Projected benefit obligation	$215	$250
Accumulated benefit obligation	168	191
Fair value of plan assets	3	31

Benefit payments that we expect to pay, including amounts related to expected future services, and the anticipated Medicare subsidies that we expect to receive are as follows for the years ending December 31 (in millions):

	Pension Benefits	Other Postretirement Benefits
2014	$100	$19
2015	125	19
2016	116	20
2017	127	20
2018	146	21
2019-2023	820	107

We plan to contribute approximately $38 million to our pension plans and $19 million to our other postretirement benefit plans during 2014.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of net periodic benefit cost were as follows for the years ended (in millions):

	Pension Plans			Other Postretirement Benefit Plans		
	December 31,			December 31,		
	2013	2012	2011	2013	2012	2011
Components of net periodic benefit cost:						
Service cost	$137	$140	$104	$12	$12	$11
Interest cost	86	93	85	18	21	22
Expected return on plan assets	(131)	(125)	(112)	—	—	—
Amortization of:						
Prior service cost (credit)	(19)	3	2	(14)	(23)	(23)
Net actuarial loss	57	33	12	—	1	2
Special charges (credits)	(5)	(3)	4	—	—	4
Net periodic benefit cost	$125	$141	$95	$16	$11	$16

Amortization of prior service cost (credit) shown in the above table was based on a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under each respective plan. Amortization of the net actuarial loss shown in the above table was based on the straight-line amortization of the excess of the unrecognized loss over 10 percent of the greater of the projected benefit obligation or market-related value of plan assets (smoothed asset value) over the average remaining service period of active employees expected to receive benefits under each respective plan. Special credits in 2013 and 2012 include curtailments and settlements related to our employees at our Aruba Refinery, partially offset by settlements related to lump sum payments in excess of thresholds. Special charges in 2011 related to purchase accounting for the Meraux Acquisition and settlements related to lump sum payments in excess of thresholds.

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pre-tax amounts recognized in other comprehensive income for the years ended were as follows (in millions):

	Pension Plans			Other Postretirement Benefit Plans		
	December 31,			December 31,		
	2013	2012	2011	2013	2012	2011
Net gain (loss) arising during the year:						
Net actuarial gain (loss)	$290	$(245)	$(294)	$77	$17	$9
Prior service cost	—	(9)	(4)	—	—	—
Remeasurement due to plan amendments	328	—	—	43	—	—
Net (gain) loss reclassified into income:						
Net actuarial loss	57	33	12	—	1	2
Prior service cost (credit)	(19)	3	2	(14)	(23)	(23)
Curtailment and settlement loss	1	12	4	—	—	—
Total changes in other comprehensive income (loss)	$657	$(206)	$(280)	$106	$(5)	$(12)

The pre-tax amounts in accumulated other comprehensive income as of December 31, 2013 and 2012 that have not yet been recognized as components of net periodic benefit cost were as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plans	
	2013	2012	2013	2012
Prior service cost (credit)	$(233)	$21	$(110)	$(81)
Net actuarial loss (gain)	479	882	(44)	34
Total	$246	$903	$(154)	$(47)

The following pre-tax amounts included in accumulated other comprehensive income as of December 31, 2013 are expected to be recognized as components of net periodic benefit cost during the year ending December 31, 2014 (in millions):

	Pension Plans	Other Postretirement Benefit Plans
Amortization of prior service credit	$(22)	$(18)
Amortization of net actuarial loss (gain)	35	(1)
Total	$13	$(19)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The weighted-average assumptions used to determine the benefit obligations as of December 31, 2013 and 2012 were as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	2013	2012	2013	2012
Discount rate	4.92 %	4.28 %	4.88 %	4.19 %
Rate of compensation increase	3.81 %	3.73 %	— %	— %

The discount rate assumption used to determine the benefit obligations as of December 31, 2013 and 2012 for the majority of our pension plans and other postretirement benefit plans was based on the Aon Hewitt AA Only Above Median yield curve and considered the timing of the projected cash outflows under our plans. This curve was designed by Aon Hewitt to provide a means for plan sponsors to value the liabilities of their pension plans or postretirement benefit plans. It is a hypothetical double-A yield curve represented by a series of annualized individual discount rates with maturities from one-half year to 99 years. Each bond issue underlying the curve is required to have an average rating of double-A when averaging all available ratings by Moody’s Investor Services (Moody’s), Standard and Poor’s Ratings Service (S&P), and Fitch Ratings. Only the bonds representing the 50 percent highest yielding issuances among those with average ratings of double-A are included in this yield curve.

We based our December 31, 2013, 2012, and 2011 discount rate assumption on the Aon Hewitt AA Only Above Median yield curve because we believe it is representative of the types of bonds we would use to settle our pension and other postretirement benefit plan liabilities as of those dates. We believe that the yields associated with the bonds used to develop this yield curve reflect the current level of interest rates.

The weighted-average assumptions used to determine the net periodic benefit cost for the years ended December 31, 2013, 2012, and 2011 were as follows:

	Pension Plans			Other Postretirement Benefit Plans		
	2013	2012	2011	2013	2012	2011
Discount rate	4.33 %	5.08 %	5.40 %	4.19 %	4.97 %	5.22 %
Expected long-term rate of return on plan assets	7.62 %	7.67 %	7.69 %	— %	— %	— %
Rate of compensation increase	3.73 %	3.68 %	3.56 %	— %	— %	— %

The assumed health care cost trend rates as of December 31, 2013 and 2012 were as follows:

	2013	2012
Health care cost trend rate assumed for the next year	7.39 %	7.32 %
Rate to which the cost trend rate was assumed to decline (the ultimate trend rate)	5.00 %	5.00 %
Year that the rate reaches the ultimate trend rate	2020	2020

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VALERO ENERGY CORPORATION
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Assumed health care cost trend rates impact the amounts reported for retiree health care plans. A one percentage-point change in assumed health care cost trend rates would have the following effects on other postretirement benefits (in millions):

	1% Increase	1% Decrease
Effect on total of service and interest cost components	$—	$—
Effect on accumulated postretirement benefit obligation	3	(3)

The tables below present the fair values of the assets of our pension plans (in millions) as of December 31, 2013 and 2012 by level of the fair value hierarchy. Assets categorized in Level 1 of the hierarchy are measured at fair value using a market approach based on quotations from national securities exchanges. Assets categorized in Level 2 of the hierarchy are measured at net asset value as a practical expedient for fair value. As previously noted, we do not fund or fully fund U.S. nonqualified and certain international pension plans that are not subject to funding requirements, and we do not fund our other postretirement benefit plans.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total as of December 31, 2013
Equity securities:				
U.S. companies[(a)]	$529	$—	$—	$529
International companies	155	—	—	155
Preferred stock	3	—	—	3
Mutual funds:				
International growth	131	—	—	131
Index funds[(b)]	160	—	—	160
Corporate debt instruments	—	260	—	260
Government securities:				
U.S. Treasury securities	81	—	—	81
Other government securities	—	79	—	79
Common collective trusts	—	373	—	373
Private fund	—	38	—	38
Insurance contracts	—	17	—	17
Interest and dividends receivable	5	—	—	5
Cash and cash equivalents	72	6	—	78
Total	$1,136	$773	$—	$1,909

See notes on page 102.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Fair Value Measurements Using			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total as of December 31, 2012
Equity securities:				
U.S. companies[(a)]	$441	$—	$—	$441
International companies	135	—	—	135
Preferred stock	2	1	—	3
Mutual funds:				
International growth	127	—	—	127
Index funds[(b)]	117	—	—	117
Corporate debt instruments	—	290	—	290
Government securities:				
U.S. Treasury securities	107	—	—	107
Other government securities	3	65	—	68
Common collective trusts	—	294	—	294
Insurance contracts	—	17	—	17
Interest and dividends receivable	5	—	—	5
Cash and cash equivalents	98	27	—	125
Total	$1,035	$694	$—	$1,729

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(a) Equity securities are held in a wide range of industrial sectors, including consumer goods, information technology, healthcare, industrials, and financial services.

(b) This class includes primarily investments in approximately 60 percent equities and 40 percent bonds.

The investment policies and strategies for the assets of our pension plans incorporate a well-diversified approach that is expected to earn long-term returns from capital appreciation and a growing stream of current income. This approach recognizes that assets are exposed to risk and the market value of the pension plans' assets may fluctuate from year to year. Risk tolerance is determined based on our financial ability to withstand risk within the investment program and the willingness to accept return volatility. In line with the investment return objective and risk parameters, the pension plans' mix of assets includes a diversified portfolio of equity and fixed-income investments. As of December 31, 2013, the target allocations for plan assets are 70 percent equity securities and 30 percent fixed income investments. Equity securities include international stocks and a blend of U.S. growth and value stocks of various sizes of capitalization. Fixed income securities include bonds and notes issued by the U.S. government and its agencies, corporate bonds, and mortgage-backed securities. The aggregate asset allocation is reviewed on an annual basis.

The expected long-term rate of return on plan assets is based on a forward-looking expected asset return model. This model derives an expected rate of return based on the target asset allocation of a plan's assets. The underlying assumptions regarding expected rates of return for each asset class reflect Aon Hewitt's best

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expectations for these asset classes. The model reflects the positive effect of periodic rebalancing among diversified asset classes. We select an expected asset return that is supported by this model.

Defined Contribution Plans

We have defined contribution plans that cover most of our employees. Our contributions to these plans are based on employees' compensation and/or a partial match of employee contributions to the plans. Our contributions to these defined contribution plans were $62 million, $61 million, and $59 million for the years ended December 31, 2013, 2012, and 2011, respectively.

15. STOCK-BASED COMPENSATION

We maintain the 2011 Omnibus Stock Incentive Plan (the OSIP) under which various stock and stock-based awards are granted to employees and non-employee directors. Awards available under the OSIP include options to purchase shares of common stock, performance awards that vest upon the achievement of an objective performance goal, stock appreciation rights, and restricted stock that vests over a period determined by our compensation committee. The OSIP was approved by our stockholders on April 28, 2011. As of December 31, 2013, 15,340,981 shares of our common stock remained available to be awarded under the OSIP.

We also maintain other stock-based compensation plans under which previously granted equity awards remain outstanding. No additional grants may be awarded under these plans.

In connection with the separation of our retail business on May 1, 2013 (as further described in Note 3), we entered into an employee matters agreement with CST, which provides that employees of CST no longer participate in our benefit plans. Under this agreement, we made certain adjustments to the exercise price and the number of our share-based compensation awards, the effect of which preserved the intrinsic value of the awards immediately prior to the separation; no incremental value resulted from these adjustments. Also upon the separation, awards of restricted stock and performance shares made to Valero employees who became employees of CST were either vested or forfeited. These adjustments are reflected in the activity tables below.

The following table reflects activity related to our stock-based compensation arrangements (in millions):

	Year Ended December 31,		
	2013	2012	2011
Stock-based compensation expense	$64	$58	$58
Tax benefit recognized on stock-based compensation expense	22	20	20
Tax benefit realized for tax deductions resulting from exercises and vestings	66	45	35
Effect of tax deductions in excess of recognized stock-based compensation expense reported as a financing cash flow	47	27	23

Each of our stock-based compensation arrangements is discussed below.

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Stock Options

Under the terms of our various stock-based compensation plans, the exercise price of options granted is not less than the fair market value of our common stock on the date of grant. Stock options become exercisable pursuant to the individual written agreements between the participants and us, usually in three equal annual installments beginning one year after the date of grant, with unexercised options generally expiring seven or ten years from the date of grant.

The fair value of stock options granted during 2013 and 2012 were estimated using the Monte Carlo simulation model, as these options contain both a service condition and a market condition in order to be exercised. Prior to 2012, the fair value of each stock option grant was estimated on the grant date using the Black-Scholes option-pricing model. The expected life of options granted is the period of time from the grant date to the date of expected exercise or other expected settlement. The expected life for each of the years in the table below was calculated using the safe harbor provisions of SEC Staff Accounting Bulletin No. 107 and No. 110 related to share-based payments. Because the stock options granted in 2012 and later contain a market condition, historical exercise patterns did not provide a reasonable basis for estimating the expected life. Expected volatility is based on closing prices of our common stock for periods corresponding to the expected life of options granted. Expected dividend yield is based on annualized dividends at the date of grant. The risk-free interest rate used is the implied yield currently available from the U.S. Treasury zero-coupon issues with a remaining term equal to the expected life of the options at the grant date.

A summary of the weighted-average assumptions used in our fair value measurements is presented in the table below.

	Year Ended December 31,					
	2013		2012		2011	
Expected life in years	6.0		6.0		6.0	
Expected volatility	49.63	%	49.11	%	49.30	%
Expected dividend yield	2.27	%	2.39	%	2.28	%
Risk-free interest rate	1.77	%	0.85	%	1.44	%

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the status of our stock option awards is presented in the table below.

	Number of Stock Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding as of January 1, 2013	13,214,728	$28.54		
Granted	201,300	39.67		
Exercised	(3,837,090)	15.21		
Expired	(1,780,113)	49.45		
Options granted on conversion related to separation of retail business	759,268	28.84		
Outstanding as of December 31, 2013	8,558,093	27.88	3.5	$216
Exercisable as of December 31, 2013	8,037,807	27.66	3.1	206

The following table reflects activity related to our stock options granted (in millions, except per share data):

	Year Ended December 31, 2013	2012	2011
Weighted average grant-date fair value price per share	$15.83	$10.98	$10.10
Intrinsic value of stock options exercised	101	78	63
Cash received from stock option exercises	59	59	49

As of December 31, 2013, there was $1 million of unrecognized compensation cost related to outstanding unvested stock option awards, which is expected to be recognized over a weighted-average period of approximately two years.

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Restricted Stock
Restricted stock is granted to employees and non-employee directors. Restricted stock granted to employees vests in accordance with individual written agreements between the participants and us, usually in equal annual installments over a period of three to five years beginning one year after the date of grant. Restricted stock granted to our non-employee directors generally vests in three years following the date of grant. A summary of the status of our restricted stock awards is presented in the table below.

	Number of Shares	Weighted-Average Grant-Date Fair Value Per Share
Nonvested shares as of January 1, 2013	2,920,288	$24.76
Granted	1,255,742	39.55
Vested	(2,113,647)	23.73
Forfeited	(31,546)	23.73
Shares granted on conversion related to separation of retail business	174,477	23.42
Nonvested shares as of December 31, 2013	2,205,314	32.23

As of December 31, 2013, there was $40 million of unrecognized compensation cost related to outstanding unvested restricted stock awards, which is expected to be recognized over a weighted-average period of approximately two years. The total fair value of restricted stock that vested during the years ended December 31, 2013, 2012, and 2011 was $74 million, $47 million, and $32 million, respectively.

Performance Awards
Performance awards are issued to certain of our key employees and represent rights to receive shares of our common stock upon the achievement by us of an objective performance measure. The objective performance measure is our total shareholder return, which is ranked among the total shareholder returns of a defined peer group of companies. Our ranking determines the rate at which the performance awards convert into our common shares. Conversion rates can range from zero to 200 percent.

Performance awards vest in equal one-third increments (tranches) on an annual basis. Our compensation committee establishes the peer group of companies for each tranche of awards at the beginning of the one year vesting period for that tranche. Therefore, performance awards are not considered to be granted for accounting purposes until our compensation committee establishes the peer group of companies for each tranche of awards. The fair value of each tranche of awards is determined at the time the awards are considered to be granted and is based on the expected conversion rate for those awards and the fair value per share. Fair value per share is equal to the market price of our common stock on the grant date reduced by expected dividends over that tranche's vesting period.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the status of our performance awards considered granted is presented below.

	Nonvested Awards	Vested Awards
Awards outstanding as of January 1, 2013	989,414	208,916
Granted	415,317	—
Vested	(442,274)	442,274
Converted	—	(534,515)
Forfeited	(50,076)	(116,675)
Shares granted on conversion related to separation of retail business	34,784	—
Awards outstanding as of December 31, 2013	947,165	—

There were three tranches of performance awards granted during the year ended December 31, 2013 as follows:

	Awards Granted	Expected Conversion Rate	Fair Value Per Share
Third tranche of 2011 awards	227,565	100%	$38.77
Second tranche of 2012 awards	105,030	100%	38.77
First tranche of 2013 awards	82,722	100%	38.77
Total	415,317		

As of December 31, 2013, there was $16 million of unrecognized compensation cost related to outstanding unvested performance awards, which will be recognized during 2014. The total fair value of performance awards that vested during the years ended December 31, 2013, 2012, and 2011 was $12 million, $3 million, and $4 million, respectively.

Performance awards converted during the year ended December 31, 2013 were as follows:

	Vested Awards Converted	Actual Conversion Rate	Number of Shares Issued	Awards Forfeited
2010 awards	417,833	100%	417,833	—
2011 awards	233,357	50%	116,682	116,675
Total	651,190		534,515	116,675

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. INCOME TAXES

Income Tax Expense
Income from continuing operations before income tax expense from U.S. and international operations was as follows (in millions):

	Year Ended December 31,		
	2013	2012	2011
U.S. operations	$3,531	$4,015	$3,190
International operations	451	(309)	132
Income from continuing operations before income tax expense	$3,982	$3,706	$3,322

The following is a reconciliation of income tax expense computed by applying the U.S. federal statutory income tax rate (35 percent for all years presented) to actual income tax expense related to continuing operations (in millions):

	Year Ended December 31,		
	2013	2012	2011
Federal income tax expense at the U.S. federal statutory rate	$1,394	$1,297	$1,163
U.S. state income tax expense, net of U.S. federal income tax effect	62	64	29
U.S. manufacturing deduction	(36)	(33)	(28)
International operations	(71)	266	46
Permanent differences	(104)	20	8
Change in tax law	(32)	—	—
Other, net	41	12	8
Income tax expense	$1,254	$1,626	$1,226

The variation in the customary relationship between income tax expense and income from continuing operations before income tax expense for the year ended December 31, 2013 was primarily due to the $325 million nontaxable gain on the disposition of our retained interest in CST as described in Notes 3 and 11. For the year ended December 31, 2012, the variation in the customary relationship between income tax expense and income from continuing operations before income tax expense was primarily due to not recognizing the tax benefit associated with the asset impairment loss of $928 million related to the Aruba Refinery, as described in Note 4, as we do not expect to realize this tax benefit.

There were no discontinued operations or related income tax benefit for the years ended December 31, 2013 and 2012. The income tax benefit related to discontinued operations for the year ended December 31, 2011 was $4 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Components of income tax expense related to continuing operations were as follows (in millions):

	Year Ended December 31,		
	2013	2012	2011
Current:			
U.S. federal	$635	$515	$562
U.S. state	36	22	13
International	82	126	186
Total current	753	663	761
Deferred:			
U.S. federal	459	854	527
U.S. state	59	77	32
International	(17)	32	(94)
Total deferred	501	963	465
Income tax expense	$1,254	$1,626	$1,226

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Deferred Income Tax Assets and Liabilities
The tax effects of significant temporary differences representing deferred income tax assets and liabilities were as follows (in millions):

	December 31, 2013	2012
Deferred income tax assets:		
Tax credit carryforwards	$48	$61
Net operating losses (NOLs)	338	247
Inventories	264	258
Property, plant, and equipment	8	78
Compensation and employee benefit liabilities	178	383
Environmental liabilities	92	83
Other	187	157
Total deferred income tax assets	1,115	1,267
Less: Valuation allowance	(347)	(304)
Net deferred income tax assets	768	963
Deferred income tax liabilities:		
Property, plant, and equipment	6,536	6,143
Deferred turnaround costs	331	300
Inventories	310	381
Investments, primarily in VLP and DGD	94	—
Other	81	103
Total deferred income tax liabilities	7,352	6,927
Net deferred income tax liabilities	$6,584	$5,964

We had the following income tax credit and loss carryforwards as of December 31, 2013 (in millions):

	Amount	Expiration
U.S. state income tax credits	$71	2014 through 2027
U.S. state NOLs (gross amount)	5,609	2014 through 2033
International NOLs	1,289	Unlimited

We have recorded a valuation allowance as of December 31, 2013 and 2012 due to uncertainties related to our ability to utilize some of our deferred income tax assets, primarily consisting of certain U.S. state income tax credits and NOLs, and international NOLs, before they expire. The valuation allowance is based on our estimates of taxable income in the various jurisdictions in which we operate and the period over which deferred income tax assets will be recoverable. During 2013, the valuation allowance increased by $43 million, primarily due to increases in U.S. state NOLs. The realization of net deferred income tax assets

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recorded as of December 31, 2013 is primarily dependent upon our ability to generate future taxable income in certain U.S. states and international jurisdictions.

Should we ultimately recognize tax benefits related to the valuation allowance for deferred income tax assets as of December 31, 2013, such amounts will be allocated as follows (in millions):

Income tax benefit	$340
Additional paid-in capital	7
Total	$347

Deferred income taxes have not been provided on the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and the respective tax bases of our international subsidiaries based on the determination that such differences are essentially permanent in duration in that the earnings of these subsidiaries are expected to be indefinitely reinvested in the international operations. As of December 31, 2013, the cumulative undistributed earnings of these subsidiaries were approximately $3.5 billion. If those earnings were not considered indefinitely reinvested, deferred income taxes would have been recorded after consideration of U.S. foreign tax credits. It is not practicable to estimate the amount of additional tax that might be payable on those earnings, if distributed.

Unrecognized Tax Benefits

The following is a reconciliation of the change in unrecognized tax benefits, excluding related penalties, interest (net of the U.S. federal and state income tax effects) and the U.S. federal income tax effect of state unrecognized tax benefits (in millions):

	Year Ended December 31,		
	2013	2012	2011
Balance as of beginning of year	$341	$326	$330
Additions based on tax positions related to the current year	64	11	14
Additions for tax positions related to prior years	576	40	55
Reductions for tax positions related to prior years	(26)	(36)	(66)
Reductions for tax positions related to the lapse of applicable statute of limitations	(4)	—	(3)
Settlements	(1)	—	(4)
Balance as of end of year	$950	$341	$326

The reconciliation of the change in unrecognized tax benefits for the year ended December 31, 2013 includes $556 million of additions for tax positions related to prior years for tax refunds that we intend to claim by amending our income tax returns for 2005 through 2012 and Premcor Inc.'s separate income tax return for 2005. We intend to propose that incentive payments received from the U.S. federal government for blending biofuels into refined products be excluded from taxable income during these periods. However, due to the complexity of this matter and uncertainties with respect to the interpretation of the Internal Revenue Code, we concluded that the $556 million refund claim cannot be recognized in our financial statements as of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2013. As a result, this amount is not included in our uncertain tax position liabilities as of December 31, 2013, even though it is reflected in the table above.

The following is a reconciliation of unrecognized tax benefits reflected in the table above to our uncertain tax position liabilities as of December 31, 2013 and 2012 that are reflected in Note 10 (in millions):

	December 31,	
	2013	2012
Unrecognized tax benefits	$950	$341
Tax refund claim not recognized in our financial statements	(556)	—
Penalties, interest (net of U.S. federal and state income tax effect), and the U.S. federal income tax effect of state unrecognized tax benefits	49	50
Uncertain tax position liabilities	$443	$391

As of December 31, 2013 and 2012, there were $763 million and $144 million, respectively, of unrecognized tax benefits that if recognized would affect our annual effective tax rate. During the next 12 months, it is reasonably possible that tax audit resolutions could reduce unrecognized tax benefits by between $100 million and $180 million, either because the tax positions are sustained on audit or because we agree to their disallowance. We do not expect these reductions to have a significant impact on our financial statements because such reductions would not significantly affect our annual effective rate.

During the years ended December 31, 2013, 2012, and 2011, we recognized $12 million, $23 million, and $1 million in penalties and interest, which is reflected within income tax expense. Accrued penalties and interest totaled $145 million and $133 million as of December 31, 2013 and 2012, respectively, excluding the U.S. federal and state income tax effects related to interest.

Tax Returns Under Audit
As of December 31, 2013, our tax years for 2002 through 2011 and Premcor Inc.'s separate tax years for 2004 and 2005 were under audit by the IRS. Premcor Inc. was merged into Valero effective September 1, 2005. The IRS has proposed adjustments to our taxable income for certain open years. We are protesting the proposed adjustments and do not expect that the ultimate disposition of these adjustments will result in a material change to our financial position, results of operations, or liquidity. We are continuing to work with the IRS to resolve these matters and we believe that they will be resolved for amounts consistent with recorded amounts of unrecognized tax benefits associated with these matters.

In January 2014, we paid the Premcor Inc. final IRS assessment for the tax years 2004 and 2005 and closed the audit related to all proposed adjustments. The amount paid was consistent with the recorded amount of unrecognized tax benefits associated with that audit.

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17. EARNINGS PER COMMON SHARE

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

	Year Ended December 31,					
	2013		2012		2011	
	Restricted Stock	Common Stock	Restricted Stock	Common Stock	Restricted Stock	Common Stock
Earnings per common share from continuing operations:						
Net income attributable to Valero stockholders from continuing operations		$2,720		$2,083		$2,097
Less dividends paid:						
Common stock		460		358		168
Nonvested restricted stock		2		2		1
Undistributed earnings		$2,258		$1,723		$1,928
Weighted-average common shares outstanding	3	542	3	550	3	563
Earnings per common share from continuing operations:						
Distributed earnings	$0.85	$0.85	$0.65	$0.65	$0.30	$0.30
Undistributed earnings	4.14	4.14	3.12	3.12	3.40	3.40
Total earnings per common share from continuing operations	$4.99	$4.99	$3.77	$3.77	$3.70	$3.70
Earnings per common share from continuing operations – assuming dilution:						
Net income attributable to Valero stockholders from continuing operations		$2,720		$2,083		$2,097
Weighted-average common shares outstanding		542		550		563
Common equivalent shares:						
Stock options		4		4		4
Performance awards and nonvested restricted stock		2		2		2
Weighted-average common shares outstanding – assuming dilution		548		556		569
Earnings per common share from continuing operations – assuming		$4.97		$3.75		$3.69

dilution

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 stock options for which the exercise prices were greater than the average market price of our common shares during each respective reporting period.

	Year Ended December 31,		
	2013	2012	2011
Stock options	1	4	6

18. SEGMENT INFORMATION

We have two reportable segments, refining and ethanol, as of December 31, 2013. Prior to May 1, 2013, we also had a retail segment. As discussed in Note 3, we completed the separation of our retail business on May 1, 2013. Segment information related to our retail business prior to the separation is reflected in the retail segment results below. Motor fuel sales to CST (our former retail business), which were eliminated in consolidation prior to the separation, are reported as refining segment operating revenues from external customers after May 1, 2013.

Our refining segment includes refining operations, wholesale marketing, product supply and distribution, and transportation operations in the U.S., Canada, the U.K., Aruba, and Ireland. Our ethanol segment primarily includes sales of internally produced ethanol and distillers grains. The retail segment included company-operated convenience stores in the U.S. and Canada; filling stations, truckstop facilities, cardlock facilities, and home heating oil operations in Canada; and credit card operations in the U.S. Operations that are not included in any of the reportable segments are included in the corporate category.

The reportable segments are strategic business units that offer different products and services. They are managed separately as each business requires unique technology and marketing strategies. Performance is evaluated based on operating income. Intersegment sales are generally derived from transactions made at prevailing market rates.

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

	Refining	Retail	Ethanol	Corporate	Total
Year ended December 31, 2013:					
Operating revenues from external customers	$129,064	$3,896	$5,114	$—	$138,074
Intersegment revenues	2,876	—	128	—	3,004
Depreciation and amortization expense	1,566	41	45	68	1,720
Operating income (loss)	4,217	81	491	(826)	3,963
Total expenditures for long-lived assets	2,597	62	33	65	2,757
Year ended December 31, 2012:					
Operating revenues from external customers	122,925	12,008	4,317	—	139,250
Intersegment revenues	8,946	—	115	—	9,061
Depreciation and amortization expense	1,370	119	42	43	1,574
Operating income (loss)	4,450	348	(47)	(741)	4,010
Total expenditures for long-lived assets	3,147	164	36	66	3,413
Year ended December 31, 2011:					
Operating revenues from external customers	109,138	11,699	5,150	—	125,987
Intersegment revenues	8,665	—	145	—	8,810
Depreciation and amortization expense	1,338	115	39	42	1,534
Operating income (loss)	3,516	381	396	(613)	3,680
Total expenditures for long-lived assets	2,708	134	32	113	2,987

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Our principal products include conventional and CARB gasolines, RBOB (reformulated gasoline blendstock for oxygenate blending), ultra-low-sulfur diesel, and gasoline blendstocks. We also produce a substantial slate of middle distillates, jet fuel, and petrochemicals, in addition to lube oils and asphalt. Other product revenues include such products as gas oils, No. 6 fuel oil, and petroleum coke. Operating revenues from external customers for our principal products were as follows (in millions):

	Year Ended December 31,		
	2013	2012	2011
Refining:			
Gasolines and blendstocks	$57,806	$55,647	$49,019
Distillates	56,921	51,504	43,713
Petrochemicals	4,281	3,908	4,253
Lubes and asphalts	1,643	2,033	1,948
Other product revenues	8,413	9,833	10,205
Total refining operating revenues	129,064	122,925	109,138
Retail:			
Fuel sales (gasoline and diesel)	3,226	10,045	9,730
Merchandise sales and other	524	1,649	1,635
Home heating oil	146	314	334
Total retail operating revenues	3,896	12,008	11,699
Ethanol:			
Ethanol	4,245	3,545	4,436
Distillers grains	869	772	714
Total ethanol operating revenues	5,114	4,317	5,150
Total operating revenues	$138,074	$139,250	$125,987

Operating revenues by geographic area are shown in the table below (in millions). The geographic area is based on location of customer and no customer accounted for more than 10 percent of our operating revenues.

	Year Ended December 31,		
	2013	2012	2011
U.S.	$100,418	$100,733	$98,806
Canada	9,974	10,376	10,110
U.K.	11,358	10,779	4,297
Other countries	16,324	17,362	12,774
Total operating revenues	$138,074	$139,250	$125,987

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Long-lived assets include property, plant, and equipment, intangible assets, and certain long-lived assets included in "deferred charges and other assets, net." Geographic information by country for long-lived assets consisted of the following (in millions):

	December 31,	
	2013	2012
U.S.	$23,572	$23,760
Canada	2,260	2,639
U.K.	1,148	1,110
Aruba	53	41
Ireland	26	37
Total long-lived assets	$27,059	$27,587

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

	December 31,	
	2013	2012
Refining	$40,834	$38,858
Retail	—	2,043
Ethanol	889	929
Corporate	5,537	2,647
Total assets	$47,260	$44,477

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19. 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):

	Year Ended December 31,		
	2013	2012	2011
Decrease (increase) in current assets:			
Receivables, net	$(753)	$437	$(3,110)
Inventories	(13)	(282)	643
Income taxes receivable	10	51	128
Prepaid expenses and other	2	(28)	(2)
Increase (decrease) in current liabilities:			
Accounts payable	977	(113)	2,004
Accrued expenses	53	13	(18)
Taxes other than income taxes	337	(260)	312
Income taxes payable	309	(120)	124
Changes in current assets and current liabilities	$922	$(302)	$81

The above changes in current assets and current liabilities differ from changes between amounts reflected in the applicable 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 for the year ended December 31, 2013 exclude the change in current assets and current liabilities resulting from the separation of our retail business as described in Note 3;
- the amounts shown above exclude the current assets and current liabilities acquired in connection with the Meraux Acquisition in October 2011 and the Pembroke Acquisition in August 2011;
- amounts accrued for capital expenditures and deferred turnaround and catalyst costs are reflected in investing activities when such amounts are paid;
- amounts accrued for common stock purchases in the open market that are not settled as of the balance sheet date are reflected in financing activities when the purchases are settled and paid; and
- certain differences between 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.

There were no significant noncash investing activities for the years ended December 31, 2013, 2012 and 2011. Noncash financing activities for the year ended December 31, 2013 included the exchange of CST's senior unsecured bonds and the exchange of all of our remaining shares of CST common stock with third-party financial institutions in satisfaction of our short-term debt agreements as described in Note 11. There were no significant noncash financing activities for the years ended December 31, 2012 and 2011.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31,		
	2013	2012	2011
Interest paid in excess of amount capitalized	$361	$302	$397
Income taxes paid, net	387	705	486

20. FAIR VALUE MEASUREMENTS

General

GAAP requires that certain assets and liabilities be measured at fair value on a recurring or nonrecurring basis in our balance sheets, which are presented below under "Recurring Fair Value Measurements" and "Nonrecurring Fair Value Measurements." Recurring fair value measurements of assets or liabilities are those that GAAP requires or permits in the balance sheet at the end of each reporting period, such as derivative financial instruments. Nonrecurring fair value measurements of assets or liabilities are those that GAAP requires or permits in the balance sheet in particular circumstances, such as the impairment of property, plant, and equipment.

GAAP also requires the disclosure of the fair values of financial instruments when an option to elect fair value accounting has been provided, but such election has not been made. A debt obligation is an example of such a financial instrument. The disclosure of the fair values of financial instruments not recognized at fair value in our balance sheet is presented below under "Other Financial Instruments."

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. 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.

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VALERO ENERGY CORPORATION
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Recurring Fair Value Measurements

The tables below present information (in millions) about our assets and liabilities recognized at their fair values in our balance sheets categorized according to the fair value hierarchy of the inputs utilized by us to determine the fair values as of December 31, 2013 and 2012.

We have elected to offset the fair value amounts recognized for multiple similar derivative contracts executed with the same counterparty, including any related cash collateral assets or obligations as shown below; however, fair value amounts by hierarchy level are presented on a gross basis in the tables below. We have no derivative contracts that are subject to master netting arrangements that are reflected gross on the balance sheet.

	December 31, 2013							
	Fair Value Hierarchy			Total Gross Fair Value	Effect of Counter-party Netting	Effect of Cash Collateral Netting	Net Carrying Value on Balance Sheet	Cash Collateral Paid or Received Not Offset
	Level 1	Level 2	Level 3					
Assets:								
Commodity derivative contracts	$499	$38	$—	$537	$ (505)	$(7)	$25	$—
Investments of certain benefit plans	98	—	11	109	n/a	n/a	109	n/a
Total	$597	$38	$11	$646	$ (505)	$(7)	$134	
Liabilities:								
Commodity derivative contracts	$492	$24	$—	$516	$ (505)	$(6)	$5	$(76)
Biofuels blending obligation	—	11	—	11	n/a	n/a	11	n/a
Physical purchase contracts	—	5	—	5	n/a	n/a	5	n/a
Foreign currency contracts	8	—	—	8	n/a	n/a	8	n/a
Total	$500	$40	$—	$540	$ (505)	$(6)	$29	

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31, 2012							
	Fair Value Hierarchy			Total Gross Fair Value	Effect of Counter-party Netting	Effect of Cash Collateral Netting	Net Carrying Value on Balance Sheet	Cash Collateral Paid or Received Not Offset
	Level 1	Level 2	Level 3					
Assets:								
Commodity derivative contracts	$1,143	$60	$—	$1,203	$ (1,189)	$—	$14	$—
Physical purchase contracts	—	11	—	11	n/a	n/a	11	n/a
Foreign currency contracts	1	—	—	1	n/a	n/a	1	n/a
Investments of certain benefit plans	87	—	11	98	n/a	n/a	98	n/a
Total	$1,231	$71	$11	$1,313	$ (1,189)	$—	$124	
Liabilities:								
Commodity derivative contracts	$1,138	$70	$—	$1,208	$ (1,189)	$(13)	$6	$(114)
Biofuels blending obligation	—	10	—	10	n/a	n/a	10	n/a
Foreign currency contracts	1	—	—	1	n/a	n/a	1	n/a
Total	$1,139	$80	$—	$1,219	$ (1,189)	$(13)	$17	

A description of our assets and liabilities recognized at fair value along with the valuation methods and inputs we used to develop their fair value measurements are as follows:

- Commodity derivative contracts consist primarily of exchange-traded futures and swaps, and as disclosed in Note 21, 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 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 21, 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 or an independent pricing service and are categorized in Level 2 of the fair value hierarchy.
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Investments of certain benefit plans consist of investment securities held by trusts for the purpose of satisfying a portion of our obligations under certain U.S. nonqualified benefit plans. The assets categorized in Level 1 of the fair value hierarchy are measured at fair value using a market approach based on quoted prices from national securities exchanges. The assets categorized in Level 3 of the fair value hierarchy represent insurance contracts, the fair value of which is provided by the insurer.

VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

- Foreign currency contracts consist of foreign currency exchange and purchase contracts entered into by our international operations to manage our exposure to exchange rate fluctuations on transactions denominated in currencies other than the local (functional) currencies of those operations. These contracts are valued based on quoted prices from the exchange and are categorized in Level 1 of the fair value hierarchy.
- Our biofuels blending obligation represents a liability for the purchase of biofuel credits (primarily RINs in the U.S.) needed to satisfy our obligation to blend biofuels into the products we produce. To the degree we are unable to blend at percentages required under various governmental and regulatory programs, we must purchase biofuel credits to comply with these programs. These programs are further described in Note 21 under "Compliance Program Risk." This liability is based on our deficit in biofuel credits as of the balance sheet date, if any, after considering any biofuel credits acquired or under contract, and is equal to the product of the biofuel credits deficit and the market price of these credits as of the balance sheet date. This liability is categorized in Level 2 of the fair value hierarchy and is measured at fair value using the market approach based on quoted prices from an independent pricing service.

There were no transfers between Level 1 and Level 2 for assets and liabilities held as of December 31, 2013 and 2012 that were measured at fair value on a recurring basis.

The following is a reconciliation of the beginning and ending balances (in millions) for fair value measurements developed using significant unobservable inputs (Level 3).

	Investments of Certain Benefit Plans			Other Investments		
	2013	2012	2011	2013	2012	2011
Balance as of beginning of year	$11	$11	$10	$—	$—	$—
Purchases	—	—	1	—	—	21
Total losses included in refining operating expense	—	—	—	—	—	(21)
Transfers in and/or out of Level 3	—	—	—	—	—	—
Balance as of end of year	$11	$11	$11	$—	$—	$—
The amount of total losses included in income attributable to the change in unrealized losses relating to assets still held at end of year	$—	$—	$—	$—	$—	$(21)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Nonrecurring Fair Value Measurements
There were no assets or liabilities that were measured at fair value on a nonrecurring basis as of December 31, 2013. The table below presents the fair value of certain assets that were measured at fair value on a nonrecurring basis as of December 31, 2012 (in millions) and the related impairment losses recognized. See Note 4 for our impairment analysis for these assets.

	Fair Value Hierarchy			Total Fair Value as of December 31, 2012	Total Losses Recognized During the Year Ended December 31, 2012
	Level 1	Level 2	Level 3		
Assets:					
Long-lived assets of the Aruba Refinery	$—	$—	$—	$—	$903
Materials and supplies inventories of the Aruba Refinery	—	—	—	—	25
Cancelled capital projects	—	—	2	2	65
Property, plant, and equipment of convenience stores	—	—	8	8	21

There were no liabilities that were measured at fair value on a nonrecurring basis as of December 31, 2012.

Other Financial Instruments
Financial instruments that we recognize in our balance sheets at their carrying amounts are shown in the table below (in millions):

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets:				
Cash and temporary cash investments	$4,292	$4,292	$1,723	$1,723
Financial liabilities:				
Debt (excluding capital leases)	6,525	7,659	7,000	8,621

The methods and significant assumptions used to estimate the fair value of these financial instruments are as follows:

- The fair value of cash and temporary cash investments approximates the carrying value due to the low level of credit risk of these assets combined with their short maturities and market interest rates (Level 1).
- The fair value of debt is determined primarily using the market approach based on quoted prices provided by third-party brokers and vendor pricing services (Level 2).

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

21. 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. We enter into derivative instruments to manage some of these risks, including derivative instruments related to the various commodities we purchase or produce, interest rate swaps, and foreign currency exchange and purchase contracts, as described below under "Risk Management Activities by Type of Risk." These derivative instruments are recorded as either assets or liabilities measured at their fair values (see Note 20), as summarized below under "Fair Values of Derivative Instruments." In addition, the effect of these derivative instruments on our income is summarized below under "Effect of Derivative Instruments on Income and Other Comprehensive Income."

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, is 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 our statements of cash flows for all periods presented.

We are also exposed to market risk related to the volatility in the price of credits needed to comply with various governmental and regulatory programs. To manage this risk, we enter into contracts to purchase these credits when prices are deemed favorable. Some of these contracts are derivative instruments; however, we elect the normal purchase exception and do not record these contracts at their fair values.

Risk Management Activities by Type of Risk

Commodity Price Risk

We are exposed to market risks related to the volatility in the price of crude oil, refined products (primarily gasoline and distillate), grain (primarily corn), soybean oil, 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 futures, swaps, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

- 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 December 31, 2013, 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 2014
Crude oil and refined products:	
Futures – long	11,857
Futures – short	12,169
Physical contracts – long	312

- 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, refined product or natural gas purchases, or refined product sales at existing market prices that we deem favorable.

As of December 31, 2013, 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).

Derivative Instrument	Notional Contract Volumes by Year of Maturity 2014
Crude oil and refined products:	
Futures – long	7,629
Futures – short	2,314
Physical contracts – short	5,315

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VALERO ENERGY CORPORATION
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 for 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 December 31, 2013, we had the following outstanding commodity derivative instruments that were used 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, and soybean oil contracts that are presented in thousands of pounds).

	Notional Contract Volumes by Year of Maturity	
Derivative Instrument	2014	2015
Crude oil and refined products:		
Swaps – long	7,261	—
Swaps – short	7,276	—
Futures – long	42,205	—
Futures – short	52,158	—
Corn:		
Futures – long	17,110	—
Futures – short	26,095	145
Physical contracts – long	12,554	156
Soybean oil:		
Futures – short	25,320	—

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

- Trading Derivatives – Our objective for 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 December 31, 2013, 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	2014	2015
Crude oil and refined products:		
Swaps – long	25,200	—
Swaps – short	25,200	—
Futures – long	84,766	3,490
Futures – short	84,397	3,665
Options – long	28,850	—
Options – short	28,600	—
Natural gas:		
Futures – long	600	1,000
Futures – short	1,150	—
Options – short	250	—
Corn:		
Futures – long	435	—
Futures – short	435	—

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. We had no interest rate derivative instruments outstanding as of December 31, 2013 and 2012, or during the years ended December 31, 2013, 2012, or 2011.

Foreign Currency Risk

We are exposed to exchange rate fluctuations on transactions entered into by our international operations that are denominated in currencies other than the local (functional) currencies of these 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 December 31, 2013, we had commitments to purchase $716 million

VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of U.S. dollars. The majority of these commitments matured on or before January 31, 2014 resulting in a gain of $12 million in the first quarter of 2014.

Compliance Program Price Risk
We are exposed to market risk related to the volatility in the price of credits needed to comply with various governmental and regulatory programs. The most significant programs impacting our operations are those that require us to blend biofuels into the products we produce, and we are subject to such programs in most of the countries in which we operate. These countries set annual quotas for the percentage of biofuels that must be blended into the motor fuels consumed in these countries. 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 applicable quota. To the degree we are unable to blend at the applicable rate, we must purchase biofuel credits (primarily RINs in the U.S.). We are exposed to the volatility in the market price of these credits, and we manage that risk by purchasing biofuel credits when prices are deemed favorable. For the years ended December 31, 2013, 2012, and 2011, the cost of meeting our obligations under these compliance programs was $517 million, $250 million, and $231 million, respectively. These amounts are reflected in cost of sales.

Maintaining Minimum Inventory Quantities
In the U.K., we are required to maintain a minimum quantity of crude oil and refined products as a reserve against shortages or interruptions in the supply of these products. To the degree we decide not to physically hold the minimum quantity of crude oil and refined products, we must purchase Compulsory Stock Obligation (CSO) tickets from other suppliers of refined products in the U.K. or other European Union (EU) member countries, and we make economic decisions as to the cost of maintaining certain quantities of crude oil and refined products versus the cost of purchasing CSO tickets. We have not entered into derivative instruments to manage the price volatility of CSO tickets. For the years ended December 31, 2013 and 2012, the cost of purchasing CSO tickets to help meet our obligations under this compliance program was $3 million and $8 million, respectively, and these amounts were reflected in cost of sales. We had no obligations under this compliance program prior to completing the Pembroke Acquisition in 2011.

Emission Allowances
Our Pembroke Refinery is subject to a maximum amount of carbon dioxide that it can emit each year under the EU Emissions Trading Scheme. Under this cap-and-trade program, we purchase emission allowances on the open market for the difference between the amount of carbon dioxide emitted and the maximum amount allowed under the program. Therefore, we are exposed to the volatility in the market price of these allowances. For the years ended December 31, 2013, 2012, and 2011 the cost of meeting our obligation under this compliance program was immaterial. We had no obligations under this compliance program prior to completing the Pembroke Acquisition in 2011.

We enter into derivative instruments (futures) to reduce the impact of this risk on our results of operations and cash flows. Our positions in these 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. As of December 31, 2013 and 2012, we had no futures contracts outstanding related to this compliance program. For the year ended December 31, 2011, the loss recognized in income on compliance program derivative instruments designated as economic hedges was immaterial and therefore not separately presented in the table below under “Effect of Derivative Instruments on Statements of Income and Other Comprehensive Income."

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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 December 31, 2013 and 2012 (in millions) and the line items in the balance sheets in which the fair values are reflected. See Note 20 for additional information related to the fair values of our derivative instruments.

As indicated in Note 20, we net fair value amounts recognized for multiple similar derivative contracts executed with the same counterparty under master netting arrangements, including cash collateral assets and obligations. 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.

	Balance Sheet Location	December 31, 2013	
		Asset Derivatives	Liability Derivatives
Derivatives designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$25	$36
Derivatives not designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$474	$455
Swaps	Receivables, net	33	18
Swaps	Prepaid expenses and other	3	—
Swaps	Accrued expenses	—	5
Options	Receivables, net	2	2
Physical purchase contracts	Inventories	—	5
Foreign currency contracts	Accrued expenses	—	8
Total		$512	$493
Total derivatives		$537	$529

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Balance Sheet Location	December 31, 2012	
		Asset Derivatives	Liability Derivatives
Derivatives designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$77	$64
Swaps	Receivables, net	15	13
Swaps	Prepaid expenses and other	2	2
Total		$94	$79
Derivatives not designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$1,066	$1,073
Swaps	Receivables, net	9	6
Swaps	Accrued expenses	32	46
Options	Receivables, net	1	4
Options	Accrued expenses	1	—
Physical purchase contracts	Inventories	11	—
Foreign currency contracts	Receivables, net	1	—
Foreign currency contracts	Accrued expenses	—	1
Total		$1,121	$1,130
Total derivatives		$1,215	$1,209

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.

There were no material amounts due from counterparties in the refining or financial services industry as of December 31, 2013 or 2012. 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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Effect of Derivative Instruments on Income and Other Comprehensive Income
The following tables provide information about the gain or loss recognized in income and other comprehensive income (OCI) on our derivative instruments and the line items in the financial statements in which such gains and losses are reflected (in millions).

Derivatives in Fair Value Hedging Relationships	Location of Gain (Loss) Recognized in Income on Derivatives	Year Ended December 31, 2013	2012	2011
Commodity contracts:				
Loss recognized in income on derivatives	Cost of sales	$(12)	$(250)	$(6)
Gain (loss) recognized in income on hedged item	Cost of sales	18	183	(23)
Gain (loss) recognized in income on derivatives (ineffective portion)	Cost of sales	6	(67)	(29)

For fair value hedges, no component of the derivative instruments' gains or losses was excluded from the assessment of hedge effectiveness for the years ended December 31, 2013, 2012, and 2011. There were no amounts recognized in income for hedged firm commitments that no longer qualified as fair value hedges during the years ended December 31, 2013 and 2011; however, a gain of $28 million was recognized in income during the year ended December 31, 2012 for hedged firm commitments that no longer qualified as fair value hedges.

Derivatives in Cash Flow Hedging Relationships	Location of Gain (Loss) Recognized in Income on Derivatives	Year Ended December 31, 2013	2012	2011
Commodity contracts:				
Gain (loss) recognized in OCI on derivatives (effective portion)		$(4)	$45	$32
Gain (loss) reclassified from accumulated OCI into income (effective portion)	Cost of sales	(2)	73	3
Gain recognized in income on derivatives (ineffective portion)	Cost of sales	21	48	5

For cash flow hedges, no component of the derivative instruments' gains or losses was excluded from the assessment of hedge effectiveness for the years ended December 31, 2013, 2012, and 2011. For the year ended December 31, 2013, cash flow hedges primarily related to forward sales of gasoline and distillates, and associated forward purchases of crude oil, with $1 million of cumulative after-tax losses on cash flow hedges remaining in accumulated other comprehensive income. We estimate that $1 million of the deferred loss as of December 31, 2013 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 years ended December 31, 2013, 2012, and 2011,

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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 (Loss) Recognized in Income on Derivatives	Year Ended December 31, 2013	2012	2011
Commodity contracts	Cost of sales	$193	$1	$(349)
Foreign currency contracts	Cost of sales	14	(38)	18
Other contract	Cost of sales	—	—	29
Total		$207	$(37)	$(302)

The gain of $29 million on the other contract for the year ended December 31, 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 $349 million on commodity contracts for the year ended December 31, 2011 includes a $542 million loss related to forward sales of refined products.

Trading Derivatives	Location of Gain (Loss) Recognized in Income on Derivatives	Year Ended December 31, 2013	2012	2011
Commodity contracts	Cost of sales	$21	$(16)	$23
RINs fixed-price contracts	Cost of sales	(20)	—	—

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VALERO ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

22. QUARTERLY FINANCIAL DATA (Unaudited)

The following table summarizes quarterly financial data for the years ended December 31, 2013 and 2012 (in millions, except per share amounts).

	2013 Quarter Ended			
	March 31	June 30 (a)	September 30	December 31
Operating revenues	$33,474	$34,034	$36,137	$34,429
Operating income	1,061	808	532	1,562
Net income	652	465	324	1,287
Net income attributable to Valero Energy Corporation stockholders	654	466	312	1,288
Earnings per common share – assuming dilution	1.18	0.85	0.57	2.38