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.

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.

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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

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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)

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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)

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See note references on page 41.

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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

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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

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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.

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.

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	—	—	—	—	—			