UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form ~~10-K~~ AR/S

03019523

(Mark One)

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

For the fiscal year ended December 31, 2002

OR

☐ **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 1-3473

TESORO PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**95-0862768** (I.R.S. Employer Identification No.)
300 Concord Plaza Drive **San Antonio, Texas** (Address of principal executive offices)	**78216-6999** (Zip Code)

APR 1 2003

Registrant's telephone number, including area code:
210-828-8484

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.16⅔ par value	New York Stock Exchange Pacific Exchange

PROCESSED
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THOMSON FINANCIAL

Securities registered pursuant to Section 12(g) of the Act: None

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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. ☑

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☑ No ☐

At June 30, 2002, the aggregate market value of the voting stock held by nonaffiliates of the registrant was approximately $490,723,296 based upon the closing price of its common stock on the New York Stock Exchange Composite tape. At February 28, 2003, there were 64,608,233 shares of the registrant's common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement pertaining to the 2003 Annual Meeting of Stockholders are incorporated by reference into Part III hereof. The Company intends to file such Proxy Statement no later than 120 days after the end of the fiscal year covered by this Form 10-K.

TESORO PETROLEUM CORPORATION

ANNUAL REPORT ON FORM 10-K

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This Annual Report on Form 10-K (including documents incorporated by reference herein) contains statements with respect to our expectations or beliefs as to future events. These types of statements are "forward-looking" and subject to uncertainties. See "Forward-Looking Statements" on page 53.

When used in this Annual Report on Form 10-K, the terms "Tesoro", "we", "our" and "us", except as otherwise indicated or as the context otherwise indicates, refer to Tesoro Petroleum Corporation and its subsidiaries.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

We are an independent refiner and marketer with two major operating segments — (1) refining crude oil and other feedstocks and selling petroleum products in bulk and wholesale markets ("Refining") and (2) selling motor fuels and convenience products and services in the retail market ("Retail"). Through our Refining segment, we manufacture products, primarily gasoline and gasoline blendstocks, jet fuel, diesel fuel and residual fuel for sale to a wide variety of commercial customers in the mid-continental and western United States. Our Retail segment distributes motor fuels through a network of gas stations, primarily under the Tesoro® and Mirastar® brands. In addition to our Refining and Retail segments, we also market and distribute petroleum products and provide logistical support services to the marine and offshore exploration and production industries operating in the Gulf of Mexico.

See Notes D, E, F, G and Q of Notes to Consolidated Financial Statements in Item 8 for additional information on our operating segments and properties.

We were incorporated in Delaware in 1968. Our principal executive offices are located at 300 Concord Plaza Drive, San Antonio, Texas 78216-6999 and our telephone number is (210) 828-8484. Our website can be found at www.tesoropetroleum.com. We make available free of charge through our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. **You may also receive a copy of the Company's Annual Report on Form 10-K, including the financial statements, free of charge by writing to Tesoro Petroleum Corporation, Attention: Investor Relations, 300 Concord Plaza Drive, San Antonio, Texas 78216-6999.**

BUSINESS DEVELOPMENTS

On May 17, 2002, we acquired a 168,000 barrel-per-day ("bpd") refinery located in Martinez, California in the San Francisco Bay area along with 70 associated retail sites in northern California. The cash purchase price for these refinery and retail assets was approximately $923 million, including approximately $130 million for feedstock, refined product and other inventories. In addition, we issued to the seller two ten-year junior subordinated notes with face amounts aggregating $150 million and a present value of approximately $61 million at the acquisition date.

In June 2002, we announced a goal to reduce debt by $500 million by the end of 2003. As part of this debt reduction, we set a goal to generate net proceeds of $200 million through asset sales. Furthermore, our senior secured credit facility required us to consummate one or more asset sales or equity offerings resulting in the receipt of cumulative net proceeds of at least $200 million by March 31, 2003. In December 2002, we sold our product pipeline system in North Dakota and Minnesota and the 70 retail stations acquired in northern California in May 2002 and completed a sale/lease-back transaction for 30 company-operated retail stations in Alaska, Hawaii, Idaho and Utah. Through these and other miscellaneous sales, we satisfied the asset sales requirement under our senior secured credit facility with the receipt of net proceeds totaling approximately $207 million in December 2002 and have reduced our term debt by $140 million (including a $16.3 million prepayment in January 2003).

REFINING SEGMENT

Overview

We own and operate six petroleum refineries, which are located in California ("California" region), Alaska and Washington ("Pacific Northwest" region), Hawaii ("Mid-Pacific" region) and North Dakota and Utah ("Mid-Continent" region), and sell refined products to a wide variety of customers in the mid-continental and western United States. During 2002, products from our refineries accounted for approximately 82% of our refined product sales volumes, with the remaining 18% purchased from other refiners and suppliers.

Our six refineries have a combined rated crude oil capacity of 558,000 bpd. We operate the largest refineries in Hawaii and Utah, the second largest refinery in Alaska, the only refinery in North Dakota and the second largest refinery in northern California. Capacity and throughput rates of crude oil and other feedstocks by refinery are as follows:

Refinery	Rated Crude Oil Capacity (bpd)	Throughout (bpd) 2002	2001	2000
California (a)				
California	168,000	94,600	—	—
Pacific Northwest				
Washington	108,000	104,000	119,400	116,600
Alaska	72,000	53,000	50,000	48,500
Mid-Pacific				
Hawaii	95,000	81,900	87,100	84,400
Mid-Continent (b)				
North Dakota	60,000	51,400	17,100	—
Utah	55,000	50,100	16,500	—
Total Refinery (a)(b)	558,000	435,000	290,100	249,500

(a) Throughput volumes in 2002 included the California refinery since we acquired it on May 17, 2002, averaged over 365 days. Throughput for the California refinery averaged over the 229 days we owned it in 2002 was 150,800 bpd.

(b) Throughput volumes in 2001 included the Mid-Continent refineries since we acquired them on September 6, 2001, averaged over 365 days. Throughput for these refineries averaged over the 117 days that we owned them in 2001 was 53,500 bpd in North Dakota and 51,500 bpd in Utah.

We reduced throughput rates at several of our refineries in 2002 in response to market conditions. Major scheduled refinery maintenance ("turnarounds") temporarily reduced throughput at our California and Washington refineries in 2002 and at our Hawaii refinery in 2000. At our Washington refinery, throughput was higher than the rated crude oil capacity in 2001 and 2000 due to operational improvements and the processing of other feedstocks in addition to crude oil.

In 2002, we received 31% of our crude oil input from domestic sources (other than Alaska), 30% from Alaska's North Slope, 7% from Alaska's Cook Inlet and 32% from foreign sources (including 9% from Canada). As shown in the table below, in 2002, approximately 49% of our total refining throughput was heavy crude oil, compared with 45% in 2001. We define "heavy" crude oil as Alaska North Slope or crude oil with an

American Petroleum Institute specific gravity of 32 or less. Actual throughput of crude oil and other feedstocks is summarized below:

	2002		2001		2000	
	Volume	%	Volume	%	Volume	%
Throughput (volumes in thousand bpd):						
California (a)						
Heavy crude	89	94%	—	—	—	—
Other feedstocks	6	6	—	—	—	—
Total	95	100%	—	—	—	—
Pacific Northwest						
Heavy crude	74	47%	78	46%	59	36%
Light crude	75	48	83	49	96	58
Other feedstocks	8	5	8	5	10	6
Total	157	100%	169	100%	165	100%
Mid-Pacific						
Heavy crude	49	60%	53	61%	47	56%
Light crude	33	40	34	39	37	44
Total	82	100%	87	100%	84	100%
Mid-Continent (b)						
Light crude	97	96%	34	100%	—	—
Other feedstocks	4	4	—	—	—	—
Total	101	100%	34	100%	—	—
Total Refining Throughput (a)(b)						
Heavy crude	212	49%	131	45%	106	43%
Light crude	205	47	151	52	133	53
Other feedstocks	18	4	8	3	10	4
Total	435	100%	290	100%	249	100%

(a) Throughput volumes in 2002 included the California refinery since we acquired it on May 17, 2002, averaged over 365 days. Throughput for the California refinery averaged over the 229 days we owned it in 2002 was 150,800 bpd.

(b) Throughput volumes in 2001 included the Mid-Continent refineries since we acquired them on September 6, 2001, averaged over 365 days. Throughput for these refineries averaged over the 117 days that we owned them in 2001 was 105,000 bpd.

We purchase crude oil and other feedstock for the refineries through term agreements and in the spot market. We purchase Alaska North Slope, California San Joaquin, Alaska Cook Inlet, Canadian and North Dakota crude oils from several suppliers under term agreements with renewal provisions. Prices under the term agreements fluctuate with market prices.

We term charter three U.S. flag tankers, two of which are double-hulled and one is double-bottomed, to transport crude oil and refined products. During 2002, we extended the term charters on two of these ships to July 2010 and extended the charter on the third ship to July 2003. In February 2003, we chartered a fourth ship, a foreign flag tanker, through January 2004, primarily to carry crude oil from Southeast Asia to our Hawaii refinery. This term charter will reduce our use of spot charters and carry approximately 20% of our cargoes from Southeast Asia. We also charter three tugs and two product barges for our Hawaii operations over varying terms ending in 2005 through 2009 with options to renew. We also charter other tankers and ocean-going barges on a short-term basis to transport crude oil and refined products.

Our refining yield consists primarily of gasoline and gasoline blendstocks, jet fuel, diesel fuel and residual fuel oil. We also manufacture other products, including liquefied petroleum gas and liquid asphalt. Our refining yield, in volume and as a percentage, is summarized below:

	2002		2001		2000	
	Volume	%	Volume	%	Volume	%
Refining Yield (volumes in thousand bpd):						
California (a)						
Gasoline and gasoline blendstocks	62	62%	—	—	—	—
Diesel fuel	22	22	—	—	—	—
Heavy oils, residual products, internally produced fuel and other	16	16	—	—	—	—
Total	100	100%	—	—	—	—
Pacific Northwest						
Gasoline and gasoline blendstocks	68	42%	73	42%	74	43%
Jet fuel	28	17	28	16	32	19
Diesel fuel	24	15	30	17	27	16
Heavy oils, residual products, internally produced fuel and other	42	26	44	25	38	22
Total	162	100%	175	100%	171	100%
Mid-Pacific						
Gasoline and gasoline blendstocks	20	24%	20	23%	21	25%
Jet fuel	26	31	27	31	26	30
Diesel fuel	12	15	14	16	12	14
Heavy oils, residual products, internally produced fuel and other	25	30	27	30	27	31
Total	83	100%	88	100%	86	100%
Mid-Continent (b)						
Gasoline and gasoline blendstocks	54	51%	18	52%	—	—
Jet fuel	10	10	4	11	—	—
Diesel fuel	29	28	9	26	—	—
Heavy oils, residual products, internally produced fuel and other	12	11	4	11	—	—
Total	105	100%	35	100%	—	—
Total Refining Yield (a)(b)						
Gasoline and gasoline blendstocks	204	45%	111	37%	95	37%
Jet fuel	64	15	59	20	58	23
Diesel fuel	87	19	53	18	39	15
Heavy oils, residual products, internally produced fuel and other	95	21	75	25	65	25
Total	450	100%	298	100%	257	100%

(a) Refining yield in 2002 included the California refinery since we acquired it on May 17, 2002, averaged over 365 days. Refining yield for the California refinery averaged over the 229 days we owned it was 160,000 bpd.

(b) Refining yield in 2001 included the Mid-Continent refineries since we acquired them on September 6, 2001, averaged over 365 days. Refining yield for these refineries averaged over the 117 days we owned them in 2001 was 108,700 bpd.

We currently operate refined product terminals in the following locations:

- California — Martinez and Stockton;
- Washington — Anacortes, Port Angeles and Vancouver;
- Alaska — Anchorage and Kenai;
- Hawaii — on the islands of Hawaii, Kauai, Maui and Oahu;
- North Dakota — Mandan;
- Utah — Salt Lake City; and
- Idaho — Boise and Burley.

As discussed above under "Business Developments", in December 2002, we sold our product pipeline extending from Mandan, North Dakota to Minneapolis, Minnesota and terminals in Jamestown, North Dakota and Moorhead, Sauk Centre and Minneapolis/St. Paul, Minnesota.

We distribute products through third-party terminals and truck racks in our market areas. Terminals we operate are supplied primarily by our refineries. Fuel distributed through third-party terminals also is supplied by our refineries and through purchases and exchange arrangements with other refining and marketing companies.

California Refinery

Refining. Our California refinery, located in Martinez on 2,206 acres of land approximately 30 miles east of San Francisco, is a highly complex refinery with a rated crude oil capacity of 168,000 bpd. Major product upgrading units at the refinery include fluid catalytic cracking ("FCC"), fluid coker, hydrocracking, naphtha reforming, vacuum distillation, hydrotreating and alkylation units. These units enable the refinery to produce a high proportion of motor fuels, including cleaner-burning California Air Resources Board ("CARB") gasoline and CARB diesel products as well as conventional gasoline and diesel. Other products produced at the refinery include liquefied petroleum gas, coke, fuel oil, decant oil and other residual products. A major turnaround of the refinery, including the fluid coker, began in the fourth quarter of 2001 and was completed in the first quarter of 2002, prior to our ownership. We completed a turnaround of the refinery's larger crude unit in the second quarter of 2002. The next scheduled turnaround is for the hydrocracker in the fourth quarter of 2004.

Following our purchase of the California refinery, we continued a project that will increase our capacity to produce CARB gasoline at the refinery by up to 20,000 bpd or approximately 30%. This project will enable us to comply with California regulations to phase out the use of the oxygenate known as MTBE, currently expected to be effective on January 1, 2004. We spent approximately $60 million through December 31, 2002 and expect to spend an additional $17 million to complete the project in the first quarter of 2003.

Crude Oil Supply. Our California refinery's crude oil is sourced primarily from California and Alaska, with the remainder purchased on a spot basis from foreign sources. We purchase approximately 65% of the refinery's crude oil under term contracts which are primarily short-term agreements at market-related prices.

Transportation. The California refinery has waterborne access that enables us to ship products and receive crude oil through our Amorco wharf and to ship and receive refined product through our Golden Eagle wharf. The Amorco wharf has a depth of 40 feet and is capable of handling vessels of up to 188,500 dead weight tons ("DWT"). The Golden Eagle wharf has a depth of 40 feet with mooring capacity to handle vessels weighing up to 105,000 DWT and measuring up to 810 feet in length. The refinery also has access to California crude oils through third-party Unocap, Shell and KLM pipelines. In addition, the refinery can receive crude oil through a third-party terminal at Martinez and can ship refined products from the refinery through the Kinder Morgan product pipeline system.

Terminals. We operate a refined product terminal at Stockton, California, and distribute products at our Martinez, California terminal by barge. In addition, we distribute products through third-party terminals and truck racks in our market areas. Fuel distributed through third-party terminals also is supplied by our refineries and through purchases and exchange arrangements with other refining and marketing companies. Under an agreement which expires in September 2004, we lease approximately 500,000 barrels of storage capacity with waterborne access in southern California.

Pacific Northwest Refineries

Washington

Refining. Our Washington refinery, located in Anacortes on the Puget Sound on 917 acres of land about 60 miles north of Seattle, has a total rated crude oil capacity of 108,000 bpd. Major product upgrading units at the refinery include the FCC, alkylation, hydrotreating, vacuum distillation and catalytic reforming units. The FCC and other product upgrading units enable the Washington refinery to produce approximately 75% of its output as light products, including gasoline (including cleaner-burning CARB gasoline), diesel and jet fuel. Actual yields depend on the mix of crude oil and other feedstock throughput. The FCC unit also can upgrade heavy vacuum gas oils from our Alaska and Hawaii refineries and other suppliers. We completed a turnaround of the FCC and alkylation units in the first quarter of 2002. The next scheduled turnaround is for the crude distillation and reformer units in the fourth quarter of 2004.

We completed a heavy oil conversion project at our Washington refinery at the end of the first quarter 2002, which enables us to process a larger proportion of lower-cost heavy crude oils, to manufacture a larger proportion of higher-value gasoline and to reduce production of lower-value heavy products.

Crude Oil Supply. The Washington refinery's crude oil is sourced primarily from Alaska, Canada and Southeast Asia. We purchase approximately 75% of the refinery's crude oil under term contracts which are primarily short-term agreements with market-related prices. The Washington refinery acquires intermediate feedstocks, primarily heavy vacuum gas oil, from some of our other refineries and by spot market purchases from third-party refineries.

Transportation. The Washington refinery receives crude oil from Canada through the 24-inch, third-party Transmountain Pipeline, which originates in Edmonton, Canada. We receive other crude oil through the Washington refinery's marine terminal. The pipeline and the marine terminal are each capable of providing 100% of the Washington refinery's feedstock needs. Our Washington refinery ships products (gasoline, jet fuel and diesel) through a third-party pipeline system, which serves the Seattle, Washington area with 16-inch and 20-inch lines and continues to Portland, Oregon with a 14-inch line. We also deliver gasoline through a neighboring refinery's truck rack, and we distribute diesel fuel through a truck rack at our refinery. We also deliver refined products through our marine terminal to ships and barges. We ship our fuel oil production by water and our propane and asphalt by truck and rail.

Terminals. We operate refined product terminals at Port Angeles and Vancouver, Washington. These terminals are supplied primarily by our Pacific Northwest refineries. In addition, we distribute products through third-party terminals and truck racks in our market areas. Fuel distributed through third-party terminals also is supplied by our refineries and through purchases and exchange arrangements with other refining and marketing companies.

Alaska

Refining. Our Alaska refinery is located near Kenai on 488 acres of land approximately 70 miles southwest of Anchorage and adjacent to the Cook Inlet where it has access to Alaskan and imported crude oil supplies. The refinery has a total rated crude oil capacity of 72,000 bpd. Major product upgrading units include the vacuum distillation, distillate hydrocracking, hydrotreating and catalytic reforming units. The Alaska refinery produces liquefied petroleum gas, gasoline and gasoline blendstocks, jet fuel, diesel fuel, heating oil, liquid asphalt, heavy oils and residual products. We completed a scheduled maintenance turnaround of all major process units at the Alaska refinery in the second quarter of 2001, and the next turnaround of all major process units is scheduled for the second quarter of 2003.

Crude Oil Supply. The Alaska refinery primarily runs Alaska Cook Inlet crude oil. To a lesser extent, the refinery runs Alaska North Slope and other crude oils. We purchase substantially all of the crude oil for the Alaska refinery under term contracts, of which approximately 72% are short-term agreements and approximately 28% are agreements for terms greater than one year, in each case with market-related prices.

Transportation. We deliver crude oil by tanker to the Alaska refinery through our Kenai Pipe Line Company marine terminal, which is a common carrier and marine dock facility. We also receive crude oil through our 24-mile pipeline connecting our marine terminal with some of the Cook Inlet producing fields. Our marine terminal is also used to load refined products on tankers and barges. We also own and operate a common-carrier petroleum products pipeline, which runs from the Alaska refinery to our terminal facilities in Anchorage and to the Anchorage airport. This 71-mile, ten-inch diameter pipeline has the capacity to transport approximately 40,000 bpd of products and allows us to transport light products to the terminal facilities throughout the year, regardless of weather conditions.

Terminals. We operate refined product terminals at Kenai and Anchorage, Alaska. These terminals are supplied by the Alaska refinery. In addition, we distribute products through third-party terminals and truck racks in our market areas. Fuel distributed through third-party terminals also is supplied by our refineries and through purchases and exchange arrangements with other refining and marketing companies.

Mid-Pacific Refinery

Hawaii

Refining. Our Hawaii refinery, located at Kapolei on 131 acres of land 22 miles west of Honolulu, produces liquified petroleum gas, gasoline and gasoline blendstocks, jet fuel, diesel fuel and fuel oil. The refinery has a total rated crude oil capacity of 95,000 bpd. Major product upgrading units include the vacuum distillation, distillate hydrocracking, hydrotreating, visbreaking and catalytic reforming units. We completed a scheduled maintenance turnaround in the third quarter of 2000, and the next turnaround of all major units is scheduled for the first quarter of 2004.

Crude Oil Supply. The Hawaii refinery's crude oil supply is sourced primarily from Alaska and Southeast Asia. We purchase approximately 55% of the refinery's crude oil under term contracts which are primarily short-term agreements with market-related prices. We purchase the remaining 45% on the spot market. The percentages of crude oil purchased under term contracts and in the spot market vary based on market conditions.

Transportation. Crude oil is transported to Hawaii by tankers and discharged through our single-point mooring terminal approximately 1.5 miles offshore from the Hawaii refinery. Three underwater pipelines connect the single-point mooring terminal to the Hawaii refinery to allow crude oil and products to be transferred to the Hawaii refinery and to load products from the Hawaii refinery to ships and barges. We distribute refined products to customers on the island of Oahu through a pipeline system, which includes connections to military facilities at several locations. We also distribute refined products to commercial customers through third-party terminals at Honolulu International Airport and Honolulu Harbor and by barge to Tesoro-owned and third-party terminal facilities on the islands of Maui, Kauai and Hawaii. Our product pipelines connect the Hawaii refinery to Barbers Point Harbor, 2.5 miles away, which is able to accommodate barges and product tankers up to 800 feet in length and reduces traffic at the single-point mooring terminal.

Terminals. We operate refined product terminals in Hawaii on the islands of Hawaii, Kauai, Maui and Oahu. In addition, we distribute products through third-party terminals and truck racks. Fuel distributed through these terminals is supplied primarily by our refinery.

Mid-Continent Refineries

North Dakota

Refining. Our North Dakota refinery is located near Mandan on 960 acres of land. The 60,000 bpd refinery is the only one in the state and serves both in-state needs and those of neighboring Minnesota. Major product upgrading units at the refinery include the FCC, reforming, hydrotreating and alkylation units. The North Dakota refinery's primary products include gasoline, diesel fuel and jet fuel. A maintenance turnaround of all major process units is scheduled at the North Dakota refinery in the fourth quarter of 2003.

Crude Oil Supply. The North Dakota refinery's crude oil supply is primarily local Williston Basin sweet crude oil. Although the current tariff structure makes local crude oil more economical, the refinery also has access to other sources of crude oil, including Canadian crude oil. We purchase approximately 75% of the refinery's crude oil under term contracts which are primarily short-term agreements with market-related prices.

Transportation. We own a crude oil pipeline system consisting of over 700 miles of pipeline that delivers all of the crude oil supply to our North Dakota refinery. Our crude oil pipeline system is configured to gather crude oil from the local Williston Basin and adjacent production areas in North Dakota and Montana and transport it to our North Dakota refinery and to regional points where there is additional demand. Our crude oil pipeline system is a common carrier subject to regulation by various local, state and federal agencies, including the Federal Energy Regulatory Commission.

In December 2002, we sold our product pipeline extending from Mandan, North Dakota to Minneapolis, Minnesota and our terminals in Jamestown, North Dakota and Moorhead, Sauk Centre and Minneapolis/St. Paul, Minnesota, together with a five-mile, 5,000 bpd pipeline to the Burlington Northern rail yard in Bismarck, North Dakota. We will continue to distribute our products through the pipeline under a tariff arrangement with the new owner, Kaneb Pipe Line Partners, L.P. ("Kaneb"). The product pipeline system distributes approximately 85% of our North Dakota refinery's production. All gasoline and distillate products produced at our refinery, with the exception of railroad-spec diesel fuel, can be shipped through the pipeline to Kaneb's terminals.

Terminals. Our terminal at the North Dakota refinery connects to the Kaneb product pipeline system and terminals located in North Dakota and Minnesota. We distribute products from our North Dakota refinery to customers primarily through these third-party terminals.

Offtake Agreements. In connection with the 2001 acquisition of the North Dakota refinery, we entered into certain offtake agreements with BP plc ("BP") for a portion of our refined products. We sold an average of 23,000 bpd of refined products in 2002 under the offtake agreements. In 2002, BP received approximately 67% of the committed product through the Minneapolis/St. Paul terminal with the remainder distributed through the Moorhead and Sauk Centre, Minnesota terminals. The offtake agreements for the Moorhead and Sauk Centre, Minnesota terminals expire in September 2004. The offtake agreement for the Minneapolis/St. Paul terminal expires in September 2006 with declining volumes in each of the last three years. Volumes under the offtake agreements are subject to further reductions under certain conditions. Sales prices under the offtake agreements are based on market prices at the time of sale.

Utah

Refining. Our Utah refinery is located in Salt Lake City on 145 acres of land. The 55,000 bpd refinery supplies products to the Utah, Idaho and eastern Washington marketing areas. The Utah refinery's primary products include gasoline, diesel fuel and jet fuel. Major product upgrading units include the FCC, reforming, hydrotreating and alkylation units. We began a maintenance turnaround of the crude distillation and reforming units in March 2003 which is expected to be completed in early April 2003.

Crude Oil Supply. The Utah refinery processes low-sulfur crude oils and has the flexibility to process various crude oils. As local crude oil supplies decline, local capacity can be replaced with Canadian light sweet or Syncrude. We purchase approximately 90% of the refinery's crude oil under term contracts which are primarily short-term agreements with market-related prices.

Transportation. Our refinery receives Canadian and Rocky Mountain crude oil by pipeline and truck from fields in Utah, Colorado, Wyoming and Canada. Local crude oils are delivered primarily through the Amoco "U" Pipeline. Canadian crude oil and other domestic crude oils are delivered primarily through another third-party pipeline system. We distribute the refinery's production through a system of both owned and third-party terminals and third-party pipeline connections primarily in Utah, Idaho and eastern Washington, with some product delivered in Nevada and Wyoming.

Terminals. In addition to sales at the refinery, we distribute product through the Chevron Pipeline to the two terminals we own at Boise and Burley, Idaho and to two terminals we lease in Pocatello, Idaho and Pasco, Washington.

Wholesale Marketing

Our Refining segment sells refined products, including gasoline and gasoline blendstocks, jet fuel, diesel fuel, heavy oil and residual products in both the bulk and wholesale markets. Sources of our product sales include products that we manufacture and products purchased or received on exchange from third parties. Our refined product sales in the Refining segment, including intersegment sales to our Retail operations, consisted of the following:

	2002(a)	2001(b)	2000
Product Sales (thousand bpd)			
Gasoline and gasoline blendstocks	264	161	135
Jet fuel	94	81	76
Diesel fuel	115	73	54
Heavy oils, residual products and other	72	61	58
Total Product Sales	545	376	323

(a) Sales volumes for 2002 include amounts for the California operations since their acquisition on May 17, 2002, averaged over 365 days.

(b) Sales volumes include amounts for the Mid-Continent operations since their acquisition on September 6, 2001, averaged over 365 days.

Gasoline and Gasoline Blendstocks. We sell gasoline and gasoline blendstocks in both the bulk and wholesale markets in the mid-continental and western United States (including Alaska and Hawaii). The demand for gasoline is seasonal in a majority of our markets, with lowest demand during the winter months.

We also sell gasoline to wholesale customers and bulk end-users (including several major oil companies) under various supply agreements. Gasoline also is delivered to refiners and marketers in exchange for product received at other locations in the mid-continental and western United States. We supply a major oil company through a product exchange agreement, under which we provide gasoline in Alaska in exchange for gasoline delivered to us on the U.S. West Coast. We also supply another major oil company in Alaska and Hawaii through a gasoline sales agreement. We also sell, at wholesale, to unbranded distributors and high-volume retailers. We distribute product through Tesoro-owned and third-party terminals and truck racks. Although our marketing strategy in Hawaii and Alaska is to maximize in-state sales, gasoline and gasoline components produced in excess of market demand may be shipped to the U.S. West Coast or exported to other markets, principally in the Asia/Pacific area.

Jet Fuel. Our refineries are major suppliers of commercial jet fuel to passenger and cargo airlines in Alaska and Hawaii. We also supply jet fuel to airports on the U.S. West Coast. We, along with other marketers, purchase additional quantities of jet fuel to supply Alaska, Hawaii and the U.S. West Coast markets. We primarily market commercial jet fuel at airports in Anchorage, Honolulu and other Hawaiian island locations, as well as at other airports in the western United States.

Diesel Fuel. We sell our diesel fuel production primarily on a wholesale basis for marine, transportation, industrial and agricultural purposes, as well as for home heating. We sell lesser amounts to end-users through marine terminals and for power generation in Hawaii and Washington. The production of diesel fuel by refiners in our market areas is generally in balance with demand. As a result of variations in seasonal demand, we ship diesel fuel to or from our Alaska and Hawaii operations.

Heavy Oil and Residual Products. Our California, Mid-Pacific and Pacific Northwest refineries have vacuum units that use atmospheric crude oil tower bottoms as a feedstock and further process these volumes into vacuum gas oil and vacuum tower bottoms. Vacuum gas oils are further processed in the Alaska and Hawaii refinery hydrocrackers, where they are converted into jet fuel, gasoline blendstocks and diesel fuel. Our California refinery further processes light cycle oil and vacuum oils through the hydrocracker, where they are converted into gasoline blendstocks and diesel fuel. Vacuum gas oil and deasphalted vacuum residua are used primarily as FCC feedstock at our Washington refinery where they are upgraded to gasoline and diesel fuel. We use vacuum tower bottoms to produce liquid asphalt, fuel oil and marine bunker fuel at our Mid-Pacific and Pacific Northwest refineries. We sell the remaining heavy fuel oils to other refineries, electric power producers and marine and industrial end-users. We sell our liquid asphalt for paving materials in Alaska, Hawaii and Washington. In Alaska and the Pacific Northwest, demand for liquid asphalt is seasonal because mild weather conditions are needed for highway construction. At our California refinery, we produce petroleum coke as a by-product of upgrading vacuum tower bottoms in the fluid coking unit. We sell the petroleum coke to industrial end-users.

We have marine fuel marketing operations through leased facilities at Port Angeles and Seattle, Washington, and Portland, Oregon, and through owned and leased facilities in Hawaii. Marine fuels sold from these locations are supplied principally by our refineries. See "Other" below for our marine services operations on the U.S. Gulf Coast, which we plan to integrate with our wholesale marketing and terminal operations during 2003.

Sales of Purchased Products. In the normal course of business, we purchase refined products manufactured by others for resale to customers. We purchase these products, primarily gasoline, jet fuel, diesel fuel and industrial and marine fuel blendstocks, mainly in the spot market. Sales of these products represented approximately 18% of total volumes we sold in 2002. We conduct our gasoline and diesel fuel purchase and resale activity primarily on the U.S. West Coast. Our jet fuel activity primarily consists of supplying markets in Alaska, California and Hawaii.

RETAIL SEGMENT

Our Retail segment sells gasoline and diesel fuel in retail markets in the mid-continental and western United States (including Alaska and Hawaii). The demand for gasoline is seasonal in a majority of our markets, with highest demand for gasoline during the summer driving season. We sell gasoline to retail customers through Tesoro-operated sites and agreements with third-party branded distributors (or "jobber/dealers"). As of December 31, 2002, our Retail segment included a network of 593 branded retail stations (under the Tesoro® and Mirastar® brands), including 234 Tesoro-operated retail gasoline stations and 359 jobber/dealer stations in the mid-continental and western United States. Our retail network provides a committed outlet for a portion of the motor fuels produced at our refineries. Currently, we have adopted a flat to modest growth strategy for our Retail segment that will focus on selected jobber investments in certain of our markets. We do not expect to build any new retail stations in 2003. The following table summarizes our retail operations as of and for the years ended December 31, 2002, 2001 and 2000:

	2002	2001	2000
Number of Branded Retail Stations (end of period)			
Tesoro —			
Tesoro-operated	154	138	63
Jobber/dealer	359	183	193
Mirastar —			
Tesoro-operated	78	55	20
Other —			
Tesoro-operated	2	20	—
Jobber/dealer	—	281	—
Total Branded Retail Stations —			
Tesoro-operated(a)	234	213	83
Jobber/dealer(b)	359	464	193
Total	593	677	276
Average Number of Branded Stations (during year)			
Tesoro-operated(c)	260	132	68
Jobber/dealer	419	274	192
Total Average Retail Stations	679	406	260
Total Fuel Volume (millions of gallons)			
Tesoro-operated	418	210	99
Jobber/dealer	372	186	116
Total Fuel Volumes	790	396	215
Average Fuel Volume Per Month Per Station (thousands of gallons)			
Tesoro-operated	134	133	122
Jobber/dealer	74	57	50
Total stations	97	81	69
Merchandise and Other Revenues (in millions)	$132	$ 71	$ 55
Merchandise Margin	27%	30%	32%

(a) Tesoro-operated stations included 31 in Alaska, 33 in Hawaii, 47 in Washington, 40 in Utah and 83 in several other western states at December 31, 2002.

(b) At December 31, 2002, the branded jobber/dealer stations included 88 in Alaska, 22 in California, 34 in Idaho, 71 in Utah, 60 in North Dakota, 44 in Washington and 40 in several other western states. The decrease in jobber/dealer stations during 2002 was primarily due to approximately 150 BP/Amoco jobber/dealer stations (included in the Mid-Continent acquisition) that did not rebrand to the Tesoro® brand name. This decision not to rebrand resulted in us no longer being those jobber/dealer stations' exclusive supplier under the terms of the acquisition agreement.

(c) The average number of Tesoro-operated stations in 2002 included 70 stations in northern California that were purchased in May 2002 (with our California refinery) and sold in December 2002.

We developed our Mirastar® brand to be used exclusively under an agreement with Wal-Mart whereby we build and operate retail fueling facilities on parking lots of selected Wal-Mart store locations. Our relationship with Wal-Mart covers 17 western states. Each of the sites under our agreement with Wal-Mart is subject to a ground lease with a ten-year primary term and two options, exercisable at our discretion, to extend a site's lease for additional terms of five years. Wal-Mart has the sole option to determine the availability of future sites. Pursuant to the terms of the agreement, Wal-Mart nominates certain sites and we have the right to accept or reject the opportunity to build a retail station at each such site, provided that we only have the right to reject up to an aggregate of 30% of the total number of nominated sites. Wal-Mart is not obligated to nominate a specific site or a certain number of sites for us. We are not obligated to pay for the right to accept or reject such nominated sites, we have not paid any up-front money for the right to accept or reject nominated sites and we are not obligated to accept a specific nominated site. The agreement does not create an exclusive relationship between Wal-Mart and us, and Wal-Mart is not prohibited from offering a site to our competitors in the 17 states covered by the agreement. If we accept a Wal-Mart nominated site, then the parameters and terms set forth in the agreement relating to the development of sites will govern. As of December 31, 2002, we had 78 Mirastar stations in operation and no sites under construction. We have no plans to build new Mirastar sites in 2003.

Many of our Tesoro-operated stations include 2-Go Tesoro® brand convenience stores that sell a wide variety of merchandise items. Our revenues from merchandise sales and other services, such as carwashes, totaled $132 million in 2002, $71 million in 2001 and $55 million in 2000.

OTHER

In addition to our Refining and Retail segments, we market and distribute petroleum products and provide logistical support services to the marine and offshore exploration and production industries operating in the Gulf of Mexico under the name Tesoro Marine Services. These operations are conducted through a network of 15 terminals located on the Texas and Louisiana coast. We also own tugboats, barges and trucks used in these operations. We plan to integrate these operations into our wholesale marketing and terminal operations during 2003.

COMPETITION AND OTHER

The petroleum industry is highly competitive in all phases, including the refining of crude oil and the marketing of refined petroleum products. The industry also competes with other industries that supply the energy and fuel requirements of industrial, commercial and individual consumers. We compete with a number of major integrated oil companies and other companies having greater financial and other resources. These competitors have a greater ability to bear the economic risks inherent in all phases of the industry. In recent years, consolidation in the refining and marketing industry has reduced the number of competitors; however, it has not reduced overall competition. In addition, unlike many of our competitors, we do not produce crude oil that can then be used in our refining operations and we are not as large as a number of our competitors that may have a competitive advantage when negotiating with crude oil producers.

Our California and Washington refineries compete with several refineries on the U.S. West Coast, including refineries that have higher refining capacity and are owned by substantially larger companies. Our Hawaii refinery competes primarily with one other refinery in Hawaii that also is located at Kapolei and has a rated crude oil capacity of 54,000 bpd. Historically, the other refinery produces lower volumes of jet fuel than our Hawaii refinery. The Alaska refinery competes primarily with other refineries in Alaska and on the U.S. West Coast. Our refining competition in Alaska includes two refineries near Fairbanks and a refinery near Valdez. We estimate that the other refineries have a combined capacity to process approximately 270,000 bpd of crude oil. After processing Alaska North Slope crude oil and removing the higher-value products, these refiners are permitted, because of their direct connection to the Trans Alaska Pipeline System, to return the remainder of the processed crude oil back into the pipeline system as "return oil" in consideration for a fee, thereby eliminating their need to transport and market lower-value products that are not in demand in Alaska. Our Alaska refinery is not directly connected to the Trans Alaska Pipeline System, and we, therefore, cannot return our lower-value products to the Trans Alaska Pipeline System. Our North Dakota refinery is the only refinery in North Dakota. Refineries in Wyoming, Montana, the Midwest and the United States Gulf Coast region are the primary competitors with our North Dakota refinery. Our Utah refinery is the largest of five refineries located in Utah. We estimate that these other refineries have a combined capacity to process approximately 107,500 bpd of crude oil. These five refineries (including our Utah refinery) collectively supply an estimated 70% of the gasoline and distillate products consumed in the states of Utah and Idaho, with the remainder imported from refineries in Wyoming and Montana.

Our jet fuel sales in Alaska are concentrated in Anchorage, where we are one of the principal suppliers to the Anchorage International Airport, a major hub for air cargo traffic between manufacturing regions in the Far East and markets in the United States and Europe. In Hawaii, jet fuel sales are concentrated in Honolulu, where we are the principal supplier to the Honolulu International Airport. We also serve four airports on other islands in Hawaii. In Washington, jet fuel sales are concentrated at the Seattle/Tacoma International Airport. We also supply jet fuel to customers in Portland, Oregon; Los Angeles, San Francisco and San Diego, California; Las Vegas and Reno, Nevada; and Phoenix, Arizona. Other refiners and marketers compete for sales at all of these airports. In Utah, jet fuel sales are concentrated in Salt Lake City. We also supply jet fuel to customers in Boise, Burley and Pocatello, Idaho. The North Dakota refinery supplies jet fuel to customers in Minneapolis/St. Paul and Moorhead, Minnesota and Bismarck and Jamestown, North Dakota. We produce jet fuel in Alaska and Hawaii, both of which periodically require additional supplies from outside the state to meet demand.

We sell our diesel fuel production primarily on a wholesale basis, competing with other refiners and marketers in all of our market areas. Refined products from foreign sources, including Canada, also compete for distillate customers in our market areas.

In connection with the 2001 acquisition of the North Dakota refinery, we entered into offtake agreements with BP to provide us with a distribution channel for a portion of our refined products produced at our North Dakota refinery. We sold an average of 23,000 bpd of refined products in 2002 under these offtake agreements. In 2002, BP received approximately 67% of this amount through the Minneapolis/St. Paul terminal with the remainder distributed through the Moorhead and Sauk Centre, Minnesota terminals. The offtake agreements for the Moorhead and Sauk Centre, Minnesota terminals expire in September 2004. The offtake agreement for the Minneapolis/St. Paul terminal expires September 2006 with declining volumes in each of the last three years. Volumes under the offtake agreements are subject to further reductions under certain conditions. Sales prices under the offtake agreements are based on market prices at the time of sale.

We distribute gasoline in Alaska, California, Hawaii, Utah, Washington and other western states through a network of Tesoro-operated retail stations and branded and unbranded jobber/dealers. Competitive factors affecting the retail marketing of gasoline include factors such as price, station appearance, location and brand-name identification. We compete against independent marketing companies and integrated oil companies when engaging in these marketing operations.

GOVERNMENT REGULATION AND LEGISLATION

Environmental Controls and Expenditures

All of our operations, like those of other companies engaged in similar business, are subject to extensive and frequently changing federal, state, regional and local laws, regulations and ordinances relating to the protection of the environment, including those governing emissions or discharges to the air and water, the handling and disposal of solid and hazardous wastes and the remediation of contamination. While we believe our facilities are in substantial compliance with current requirements, over the next several years we expect our facilities will be engaged in meeting new requirements being adopted and promulgated by the U.S. Environmental Protection Agency and the states and local jurisdictions in which we operate. For example, under the federal Clean Air Act we will be required to comply with the second phase of regulations establishing Maximum Achievable Control Technologies for petroleum refineries ("Refinery MACT II"). These regulations, promulgated in April 2002, will require additional air emission controls for certain processing units at several of our refineries. We expect to spend approximately $44 million in additional capital improvements at our refineries through 2006 to comply with the Refinery MACT II standards. We are currently evaluating a selection of control technologies to assure operations flexibility and compatibility with long-term air emission reduction goals.

Changes in fuel manufacturing standards, including those related to gasoline and diesel fuel sulfur concentrations, also affect our operations. In February 2000, the EPA finalized new regulations pursuant to the Clean Air Act requiring a reduction in the sulfur content in gasoline beginning January 1, 2004. To meet the revised gasoline standard, we currently estimate we will make capital improvements of approximately $37 million through 2006 and an additional $15 million thereafter. This will allow all of our refineries to produce gasoline meeting the limits imposed by the EPA. The EPA also promulgated new regulations in January 2001 pursuant to the Clean Air Act requiring a reduction in the sulfur content in diesel fuel manufactured for on-road consumption. In general, the new diesel fuel standards will become effective on June 1, 2006. Based on our latest engineering estimates, we expect to spend approximately $55 million in capital improvements through 2007 to meet the new diesel fuel standards. These expenditures, however, do not include amounts for our Alaska refinery where limited demand for low-sulfur diesel presently does not justify the capital investment. We expect to meet this demand from other sources.

To meet California's CARB III gasoline requirements, including the mandatory phase-out of the oxygenate known as MTBE, we spent approximately $60 million through December 31, 2002 on a project at our California refinery and expect to spend an additional $17 million to complete the project in the first quarter of 2003.

In connection with the 2001 acquisition of our North Dakota and Utah refineries, we assumed the sellers' obligations and liabilities under a consent decree among the United States, BP Exploration and Oil Co., Amoco Oil Company and Atlantic Richfield Company. BP entered into this consent decree for both the North Dakota and Utah refineries for various alleged violations. As the new owner of these refineries, we are required to address issues including leak detection and repair, flaring protection and sulfur recovery unit optimization. We currently estimate that we will spend an aggregate of $7 million to comply with this consent decree. In addition, we have agreed to indemnify the sellers for all losses incurred in connection with the consent decree.

In connection with the 2002 acquisition of our California refinery, subject to certain conditions, we assumed the seller's obligations pursuant to its settlement efforts with the EPA concerning the Section 114 refinery enforcement initiative under the Clean Air Act, except for any potential monetary penalties, which the seller retains. We believe these obligations will not have a material impact on our financial position.

Capital expenditures addressing other environmental issues at our California refinery totaled approximately $12 million in 2002. Based on latest estimates, we will need to expend additional capital for reconfiguring and replacing above-ground storage tank systems and upgrading piping within the refinery. These costs are currently estimated at approximately $130 million through 2007 and an additional $90 million through 2011. Both of these estimates are subject to further review and analysis.

Conditions that require additional expenditures may transpire for our various sites, including, but not limited to, our refineries, tank farms, retail gasoline stations (operating and closed locations) and petroleum product terminals, and for compliance with the Clean Air Act and other state, federal and local requirements. We cannot currently determine the amount of these future expenditures.

Oil Spill Prevention and Response

We operate in environmentally sensitive coastal waters, where tanker, pipeline and refined product transportation operations are closely regulated by local and federal agencies and monitored by environmental interest groups. The transportation of crude oil and refined product over water involves risk and subjects us to the provisions of the Federal Oil Pollution Act of 1990 and related state regulations, which require that most oil refining, transport and storage companies maintain and update various oil spill prevention and oil spill contingency plans. We have submitted these plans and received federal and state approvals necessary to comply with the Federal Oil Pollution Act of 1990 and related regulations. Our oil spill prevention plans and procedures are frequently reviewed and modified to prevent oil and product releases and to minimize potential impacts should a release occur.

We currently charter on a long-term and short-term basis tankers to ship crude oil from foreign and domestic sources to our California, Mid-Pacific and Pacific Northwest refineries. The Federal Oil Pollution

Act of 1990 requires, as a condition of operation, that we demonstrate the capability to respond to the "worst case discharge" to the maximum extent practicable. As an example, the State of Alaska requires us to provide spill-response capability to contain or control and cleanup an amount equal to 50,000 barrels of crude oil for a tanker carrying fewer than 500,000 barrels or 300,000 barrels for a tanker carrying more than 500,000 barrels. To meet these requirements, we have entered into contracts with various parties to provide spill response services. We have entered into spill-response agreements with: (1) Cook Inlet Spill Prevention and Response, Incorporated and Alyeska Pipeline Service Company for spill-response services in Alaska; (2) Clean Islands Council for response services throughout the State of Hawaii; (3) Clean Sound Incorporated for response actions associated with the Puget Sound, Washington operations; and (4) Clean Bay Incorporated for response services associated with our California refinery. In addition, for larger spill contingency capabilities, we have entered into contracts with Marine Spill Response Corporation in Hawaii and on the U.S. West Coast and Gulf Coast. We believe these contracts, and those with other regional spill-response organizations that are in place on a location by location basis, provide the additional services necessary to meet spill-response requirements established by state and federal law.

Regulation of Pipelines

Our crude oil pipeline system in North Dakota and our pipeline systems in Alaska are common carriers subject to regulation by various local, state and federal agencies, including the Federal Energy Regulatory Commission ("FERC") under the Interstate Commerce Act. The Interstate Commerce Act provides that, to be lawful, the rates of common carrier petroleum pipelines must be "just and reasonable" and not unduly discriminatory.

The intrastate operations of our crude oil pipeline system are subject to regulation by the North Dakota Public Services Commission. The intrastate operations of our Alaska pipelines are subject to regulation by the Alaska Public Utilities Commission. Like the FERC, the state regulatory authorities require that shippers be notified of proposed intrastate tariff increases and have an opportunity to protest the increases. The North Dakota Public Services Commission also files with the state authorities copies of interstate tariff charges filed with the FERC. In addition to challenges to new or proposed rates, challenges to intrastate rates that have already become effective are permitted by complaint of an interested person or by independent action of the appropriate regulatory authority.

EMPLOYEES

At December 31, 2002, we had approximately 3,940 full-time employees. Approximately 1,060 of our employees are covered by collective bargaining agreements that run until January 31, 2006. During the term of the agreements, our employees have agreed not to engage in a strike, work stoppage or slowdown, or any other interference of work production for any reason. We consider our relations with our employees to be satisfactory.

PROPERTIES

Our principal properties are described above under the captions "Refining Segment" and "Retail Segment". In addition, we own feedstock and refined product storage facilities at our refinery and terminal locations. 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. We are the lessee under a number of cancellable and noncancellable leases for certain properties, including office facilities, retail facilities, transportation equipment and various assets used to store and transport refinery feedstocks and refined products. See Notes G and Q of Notes to Consolidated Financial Statements in Item 8.

We conduct our retail business under the Tesoro®, Tesoro Alaska®, Mirastar®, and 2-Go Tesoro® brands. Our retail-marketing system under these brands includes 593 branded retail stations, of which 234 are Tesoro-operated.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following is a list of the Company's executive officers, their ages and their positions with the Company at February 28, 2003.

Name	Age	Position	Position Held Since
Bruce A. Smith	59	Chairman of the Board of Directors, President and Chief Executive Officer	June 1996
William T. Van Kleef	51	Executive Vice President and Chief Operating Officer	July 1998
James C. Reed, Jr.	58	Executive Vice President, General Counsel and Secretary	September 1995
Thomas E. Reardon	56	Executive Vice President, Corporate Resources	November 1999
W. Eugene Burden	54	Senior Vice President, Human Resources and Government Relations	June 2002
Everett D. Lewis	55	Senior Vice President, Planning and Optimization	February 2003
Gregory A. Wright	53	Senior Vice President and Chief Financial Officer	April 2001
Sharon L. Layman	49	Vice President and Treasurer	November 1999
Susan A. Lerette	44	Vice President, Communications	April 2001
Otto C. Schwethelm	48	Vice President and Controller	February 2003
G. Scott Spendlove	39	Vice President, Finance	January 2002
Rodney S. Cason	53	President, Tesoro Alaska Company	April 2002
Faye W. Kurren	52	President, Tesoro Hawaii Corporation	May 1998
Donald A. Nyberg	51	President, Tesoro Marine Services, LLC	November 1996
Stephen L. Wormington	58	Executive Vice President, Marketing, Tesoro Refining and Marketing Company	September 2002
Joseph M. Monroe	48	Senior Vice President, Supply and Distribution, Tesoro Refining and Marketing Company	May 2002
James L. Taylor	49	Senior Vice President, Manufacturing, Tesoro Refining and Marketing Company	July 2001
Alan R. Anderson	47	Senior Vice President and President, Northern Great Plains Region, Tesoro Refining and Marketing Company	June 2002
J. William Haywood	50	Senior Vice President and President, California Region, Tesoro Refining and Marketing Company	September 2002
Daniel J. Porter	47	Senior Vice President and President, Northwest Region, Tesoro Refining and Marketing Company	June 2002
Rick D. Weyen	44	Senior Vice President and President, Mountain Region, Tesoro Refining and Marketing Company	September 2001

There are no family relationships among the officers listed, and there are no arrangements or understandings pursuant to which any of them were elected as officers. Officers are elected annually by the Board of Directors at its first meeting following the Annual Meeting of Stockholders. The term of each office runs until the corresponding meeting of the Board in the next year or until a successor shall have been elected or shall have qualified.

The Company's executive officers have been employed by the Company or its subsidiaries in an executive capacity for at least the past five years, except for those named below who have had the business experience indicated during that period. Positions, unless otherwise specified, are with the Company.

W. Eugene Burden was named Senior Vice President, Human Resources and Government Relations in June 2002. Prior to that, he served as President of Tesoro Alaska Company from February 2001 to June 2002 and Senior Vice President and President, Northwest Region of Tesoro Refining and Marketing Company from September 2001 until June 2002. Mr. Burden served as Senior Vice President, Government Relations of Tesoro Petroleum Companies, Inc. from September 1999 to February 2001. Prior to joining Tesoro, he was President of Burden & Associates, Inc., which provided consulting services to energy clients in the United States and foreign operations, from February 1996 to September 1999.

Everett D. Lewis has been Senior Vice President, Planning and Optimization since February 2003. Prior to that, he was Senior Vice President, Planning and Risk Management from April 2001 to February 2003. He served as Senior Vice President of Strategic Projects from March 1999 to April 2001 and was a consultant to the refining and marketing industry from 1997 to 1999.

Sharon L. Layman has been Vice President and Treasurer since November 1999. Ms. Layman was Assistant Treasurer from February 1990 to November 1999.

Susan A. Lerette has been Vice President, Communications since April 2001. She was Director, Investor Relations from April 1999 to April 2001. From December 1998 to April 1999, Ms. Lerette served as Manager, Investor Relations and from 1994 until December 1998, she was Senior Financial Analyst in our Investor Relations Department.

Otto C. Schwethelm was named Vice President and Controller in February 2003. From September 2002 to February 2003, Mr. Schwethelm served as Vice President and Operations Controller. Prior to that, he served as Vice President, Shared Services of Tesoro Petroleum Companies, Inc. from December 2001 to September 2002. From November 1999 to December 2001, Mr. Schwethelm was Vice President, Development and Business Analysis, and from August 1998 to November 1999, he was Manager, Economics of Tesoro Petroleum Companies, Inc. Prior to joining Tesoro, he was employed by Saudi Aramco in its Internal Audit Department from July 1991 to August 1998.

G. Scott Spendlove joined Tesoro in January 2002 as Vice President, Finance. Prior to joining Tesoro, he served as Vice President, Corporate Planning and Investor Relations of Ultramar Diamond Shamrock Corporation from December 1999 to December 2001. From June 1998 to December 1999, Mr. Spendlove served as Director, Investor Relations, and from January 1997 to June 1998, as Manager, Corporate Finance of Ultramar Diamond Shamrock Corporation.

Rodney S. Cason has served as President of Tesoro Alaska Company since April 2002. Prior to that, he was Vice President, Refining, from February 1998 to April 2002, and was refinery manager from May 1997 to February 1998.

Faye W. Kurren has been President of Tesoro Hawaii Corporation since May 1998. Prior to that, she was Vice President, Operations Planning, Supply and International Marketing of BHP Hawaii Inc. from March 1996 to May 1998.

Joseph M. Monroe was named Senior Vice President, Supply and Distribution, of Tesoro Refining and Marketing Company in May 2002. From January 1999 through May 2002, Mr. Monroe served as Vice President, Pipelines and Terminals of Unocal Corporation and as President of Unocal Pipeline Company. He served Unocal Corporation as Managing Director of International Pipelines and Fuel Management from May 1998 to January 1999 and as Senior Vice President of New Ventures in Jakarta, Indonesia from July 1996 to May 1998.

James L. Taylor joined Tesoro in July 2001 as Senior Vice President, Manufacturing, of Tesoro Refining and Marketing Company. During 2000 and 2001, he served as General Manager, Worldwide Technical Services, of Criterion Catalysts and Technologies. Prior to that, Mr. Taylor was with KBC Advanced Technologies, as Job Controller from 1998 to 2000 and as Senior Consultant from 1997 to 1998.

Alan R. Anderson was named President of Tesoro Refining and Marketing Company's Northern Great Plains Region in June 2002. He also serves as manager of our North Dakota refinery. From September 2001 until June 2002, Mr. Anderson served as Business Manager of our Northern Great Plains Region. From January 1999 to September 2001, he was employed by BP as a Commercial Manager, and from August 1997 to January 1999 he was employed by Amoco as Business Manager at the North Dakota refinery. From August 1997 to September 2001 he also served as business manager for the region, which included North and South Dakota, Kansas, Minnesota and Nebraska.

J. William Haywood joined Tesoro in May 2002 as Senior Vice President and also became President of the California Region of Tesoro Refining and Marketing Company in September 2002. Prior to joining Tesoro, Mr. Haywood served as Regional Vice President of Ultramar Diamond Shamrock Corporation, responsible for both California refineries from September 2000 to May 2002. From September 1997 to September 2000, Mr. Haywood was General Manager of the Wilmington refinery near Los Angeles, California, for Ultramar Diamond Shamrock Corporation.

Daniel J. Porter joined Tesoro as Senior Vice President and President of the Northern Great Plains Region of Tesoro Refining and Marketing Company in September 2001 and became Senior Vice President and President of our Northwest Region in June 2002. Prior to joining Tesoro, he was Business Unit Leader at BP's North Dakota refinery since January 1999. He was the Downstream Business Consultant, BP Headquarters, London from January 1998 to January 1999.

Rick D. Weyen joined Tesoro as Senior Vice President and President of the Mountain Region of Tesoro Refining and Marketing Company in September 2001. He was Commercial Manager from January 1999 to September 2001 for BP and Supply and Optimization Manager from 1995 to January 1999 for Amoco at the Salt Lake City refinery.

BOARD OF DIRECTORS OF THE REGISTRANT

The following is a list of the Company's Board of Directors:

Bruce A. Smith	Chairman, President and Chief Executive Officer of Tesoro Petroleum Corporation
Steven H. Grapstein	Lead Director of Tesoro Petroleum Corporation; Chief Executive Officer of Kuo Investment Company
William J. Johnson	Petroleum Consultant; President of JonLoc Inc.
A. Maurice Myers	Chairman, President and Chief Executive Officer of Waste Management Inc.
Donald H. Schmude	Retired Vice President of Texaco and President and Chief Executive Officer of Texaco Refining & Marketing Inc.
Patrick J. Ward	Retired Chairman, President and Chief Executive Officer of Caltex Petroleum Corporation

RISK FACTORS

We have a substantial amount of debt that has limited and could further limit our flexibility in operating our business or limit our access to funds we need to grow our business.

As of December 31, 2002, we had total consolidated indebtedness of $1.9 billion (excluding an additional $165 million available under our revolving credit facility). We are rated BB-/B with a negative outlook, B1/B3 with a stable outlook and BB-/B with a negative outlook by Standard & Poor's Rating Services, Moody's Investors Service, Inc. and Fitch Rating, respectively. Our high degree of leverage may have important consequences, including the following:

- a substantial portion of our cash flow is used to service debt, which reduces the funds that would otherwise be available for operations and future business opportunities;
- our debt level makes us more vulnerable to the impact of economic downturns and adverse developments in our business;
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- we may have difficulties obtaining additional or favorable financing for capital expenditures, working capital, acquisitions or other purposes;
- our debt level may impact our level of discretionary capital expenditures and related expansion opportunities; and
- our debt level may place us at a competitive disadvantage to our less leveraged competitors.

Our ability to meet our expenses and debt obligations, to refinance our debt obligations and to fund capital expenditures will depend on our future performance, which will be affected by general economic, financial, competitive, legislative, regulatory and other factors beyond our control.

Our business may not generate sufficient cash flow, or we may not be able to borrow funds under our senior secured credit facility, in an amount sufficient to enable us to service our indebtedness or make capital expenditures. If we are unable to generate sufficient cash flow from operations or to borrow sufficient funds, we may be required to sell assets, eliminate or defer capital expenditures, refinance all or a portion of our existing debt or obtain additional financing. We may not be able to refinance our debt, sell assets or borrow more money on terms acceptable to us, if at all. Additionally, our ability to incur additional debt will be restricted under the covenants contained in our senior secured credit facility and our indentures.

Our debt instruments impose restrictions on us that may adversely affect our ability to operate our business.

Our senior secured credit facility contains covenants, including a provision that limits our capital expenditures to no more than $237.5 million for the twelve-month period ending June 30, 2003 and $210 million for the year 2003 and annually thereafter until the ratio of our debt to capitalization falls below 0.58 to 1.00. It also contains a prohibition of making voluntary or optional prepayments of certain of our indebtedness until the senior secured credit facility is repaid. Under our senior secured credit facility, we are not permitted to declare or pay cash dividends on our common stock or repurchase shares of our common stock through December 31, 2003. Our senior secured credit facility requires us to comply with specified financial covenants which, beginning with the 2003 third quarter, become more restrictive over the life of our senior secured credit facility. Our ability to comply with these covenants, as they currently exist or as they may be amended, may be affected by many events beyond our control and our future operating results may not allow us to comply with the covenants, or in the event of a default, to remedy that default. Our failure to comply with those financial covenants or to comply with the other restrictions contained in our senior secured credit facility could result in a default, which could cause that indebtedness (and by reason of cross-default provisions, indebtedness under the indentures governing our senior subordinated notes and other indebtedness) to become immediately due and payable. If we are unable to repay those amounts, the lenders under our senior secured credit facility could proceed against the collateral granted to them to secure that indebtedness. If those lenders accelerate the payment of the senior secured credit facility, we cannot assure you that we could pay that indebtedness immediately and continue to operate our business.

In addition, the indentures for our senior subordinated notes contain other covenants that restrict, among other things, our ability to:

- pay dividends and other distributions with respect to our capital stock and purchase, redeem or retire our capital stock;
- incur additional indebtedness and issue preferred stock;

- enter into asset sales unless the proceeds from those asset sales are used to repay debt;
- enter into transactions with affiliates;
- incur liens on assets to secure certain debt;
- engage in certain business activities; and
- engage in certain mergers or consolidations and transfers of assets.

Our high level of debt affects our access to trade credit.

Because of our high level of debt, combined with the recent weakness in industry refining margins and economic uncertainty, we have experienced a tightening of the trade credit we receive, requiring us to commit available cash which we could otherwise use to reduce our debt. Under current economic conditions and in light of the general uncertainty that surrounds business, we cannot assure you that the trade credit extended to us will not be further tightened. A significant further tightening in trade credit could result in our business not generating sufficient cash flow to fund operations, capital expenditures and debt service.

The volatility of crude oil prices, refined product prices and natural gas and electrical power prices may have a material adverse effect on our cash flow and results of operations.

Our earnings and cash flows from our refining and wholesale marketing operations depend on a number of factors, including fixed and variable expenses (including the cost of refinery feedstocks) and the margin above those expenses at which we are able to sell refined products. In recent years, the prices of crude oil and refined products have fluctuated substantially. These prices depend on numerous factors beyond our control, including the demand for crude oil, gasoline and other refined products, which are subject to, among other things:

- changes in the economy and the level of foreign and domestic production of crude oil and refined products;
- threatened or actual terrorist incidents, acts of war, and other worldwide political conditions;
- availability of crude oil and refined products and the infrastructure to transport crude oil and refined products;
- weather conditions, earthquakes or other natural disasters;
- government regulations; and
- local factors, including market conditions and the level of operations of other refineries in our markets.

Prices for refined products are influenced by the commodity price of crude oil. Generally, an increase or decrease in the price of crude oil results in a corresponding increase or decrease in the price of gasoline and other refined products. The timing of the relative movement of the prices as well as the overall change in product prices, however, can reduce profit margins and could have a significant impact on our refining and wholesale marketing operations and our earnings and cash flow. Industry margins deteriorated beginning in the fourth quarter of 2001 and continued throughout 2002, which adversely impacted our profit margins, earnings and cash flows. In addition, we maintain inventories of crude oil, intermediate products and refined products, the values of which are subject to rapid fluctuation in market prices. Also, crude oil supply contracts are generally term contracts with market-responsive pricing provisions. We purchase our refinery feedstocks prior to selling the refined products manufactured. Price level changes during the period between purchasing feedstocks and selling the manufactured refined products from these feedstocks could have a significant effect on our financial results. We also purchase refined products manufactured by others for sale to our customers. Price level changes during the periods between purchasing and selling these products could have a material adverse effect on our business, financial condition and results of operations.

The rising costs and unpredictable availability of natural gas and electrical power used by our refineries and other operations have increased manufacturing and operating costs and will continue to impact production and delivery of products. Fuel and utility prices have been and will continue to be affected by supply and demand for fuel and utility services in both local and regional markets.

Our business is impacted by risks inherent in petroleum refining operations.

The operation of refineries, pipelines and product terminals is inherently subject to spills, discharges or other releases of petroleum or hazardous substances. If any of these events has previously occurred or occurs in the future in connection with any of our refineries, pipelines or product terminals other than events for which we are indemnified, we will be liable for all costs and penalties associated with their remediation under federal, state and local environmental laws or common law, and will be liable for property damage to third parties caused by contamination from releases and spills. The penalties and clean-up costs that we could have to pay for releases or spills, or the amounts that we could have to pay to third parties for damage to their property, could be significant and the payment of these amounts could have a material adverse effect on our business, financial condition and results of operations.

We operate in environmentally sensitive coastal waters, where tanker, pipeline and refined product transportation operations are closely regulated by local and federal agencies and monitored by environmental interest groups. Our California, Mid-Pacific and Pacific Northwest refineries import crude oil feedstocks by tanker. Transportation of crude oil and refined product over water involves inherent risk and subjects us to the provisions of the Federal Oil Pollution Act of 1990 and state laws in California, Washington, Hawaii, Alaska and the U.S. Gulf Coast. Among other things, these laws require us to demonstrate in some situations our capacity to respond to a "worst case discharge" to the maximum extent possible. We have contracted with various spill response service companies in the areas in which we transport crude oil and refined product to meet the requirements of the Federal Oil Pollution Act of 1990 and state laws. However, there may be accidents involving tankers transporting crude oil or refined products, and response services may not respond to a "worst case discharge" in a manner that will adequately contain that discharge or we may be subject to liability in connection with a discharge.

Our operations are inherently subject to accidental spills, discharges or other releases of petroleum or hazardous substances that may make us liable to governmental entities or private parties under federal, state or local environmental laws, as well as under common law. These may involve contamination associated with facilities we currently own or operate, facilities we formerly owned or operated and facilities to which we sent wastes or by-products for treatment or disposal and other contamination. Accidental discharges may occur in the future, future action may be taken in connection with past discharges, governmental agencies may assess damages or penalties against us in connection with any past or future contamination, or third parties may assert claims against us for damages allegedly arising out of any past or future contamination.

The dangers inherent in our operations and the potential limits on insurance coverage could expose us to potentially significant liability costs.

Our operations are subject to hazards and risks inherent in refining operations and in transporting and storing crude oil and refined products, such as fires, natural disasters, explosions, pipeline ruptures and spills and mechanical failure of equipment at our or third-party facilities, any of which can result in environmental pollution, personal injury claims and other damage to our properties and the properties of others. In addition, we operate six petroleum refineries, any of which could experience a major accident, be damaged by severe weather or other natural disaster, or otherwise be forced to shut down. Any such unplanned shutdown could have a material adverse effect on our results of operations and financial condition as a whole. In addition, because of past incidents that occurred while the California refinery was under previous ownership, the cost to insure the refinery may remain substantially above industry norms. We do not maintain insurance coverage against all potential losses and we could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Our operations are subject to general environmental risks, expenses and liabilities which could affect our results of operations.

From time to time we have been, and presently are, subject to litigation and investigations with respect to environmental and related matters. We may become involved in further litigation or other proceedings, or we may be held responsible in any existing or future litigation or proceedings, the costs of which could be material.

We have in the past operated service stations with underground storage tanks in various jurisdictions, and currently operate service stations that have underground storage tanks in Hawaii, Alaska and 16 states in the mid-continental and western United States. Federal and state regulations and legislation govern the storage tanks and compliance with these requirements can be costly. The operation of underground storage tanks also poses certain other risks, including damages associated with soil and groundwater contamination. Leaks from underground storage tanks which may occur at one or more of our service stations, or which may have occurred at our previously operated service stations, may impact soil or groundwater and could result in fines or civil liability for us.

All of our operations, like those of other companies engaged in similar business, to some degree, are subject to extensive and frequently changing federal, state, regional and local laws, regulations and ordinances relating to the protection of the environment, including those governing emissions or discharges to the air and water, the handling and disposal of solid and hazardous wastes and the remediation of contamination. The failure to comply with these regulations can lead, among other things, to civil and criminal penalties and, in some circumstances, the temporary or permanent curtailment or shutdown of all or part of our operations in one or more of our facilities. The nature of our business exposes us to risks of liability due to the production, processing and refining, storage, transportation, and disposal of materials that can cause contamination or personal injury if released into the environment. Our operations are inherently subject to accidental spills, discharges or other releases of petroleum or hazardous substances that could make us responsible for cleanup costs and related penalties or liable to governmental entities or private parties. This may involve facilities we currently own or operate, facilities we formerly owned or operated and facilities to which we sent wastes or by-products for treatment or disposal. In addition, we operate in environmentally sensitive coastal waters, where tanker, pipeline and refined product transportation operations are closely regulated by local and federal agencies and monitored by environmental interest groups. The transportation of crude oil and refined product over water involves risk and subjects us to the provisions of the Federal Oil Pollution Act of 1990 and related state regulations, which require that most oil refining, transport and storage companies maintain and update various oil spill prevention and oil spill contingency plans.

Consistent with the experience of all U.S. refineries, environmental laws and regulations have raised operating costs and necessitated significant capital investments at our refineries. We believe that existing physical facilities at our refineries are substantially adequate to maintain compliance with existing applicable laws and regulatory requirements. However, potentially material expenditures could be required in the future. For example, we may be required to comply with evolving environmental and health and safety laws, regulations or requirements that may be adopted or imposed in the future or to address information or conditions that may be discovered in the future and that require a response. Several recently passed regulations will require us to complete the following projects at our refineries prior to the effective date of the related requirements and regulations:

- Upgrades to sulfur removal capabilities, which are required to comply with mandates adopted by the EPA to reduce the sulfur content of diesel fuel and gasoline;

- Changes that are required to address a ban on the gasoline additive MTBE in California; and

- Changes that will be required to comply with the terms of a settlement agreement with the EPA of alleged violations by previous owners of certain provisions of the federal Clean Air Act of 1990 (the "Clean Air Act") at our Mid-Continent refineries and a potential settlement at our California refinery.

Terrorist attacks and threats or actual war, including particularly war with Iraq, may negatively impact our business.

Our business is affected by general economic conditions and fluctuations in consumer confidence and spending, which can decline as a result of numerous factors outside of our control, such as actual or threatened terrorist attacks and acts of war. Terrorist attacks in the United States, as well as events occurring in response to or in connection with them, including future terrorist attacks against U.S. targets, rumors or threats of war, actual conflicts involving the United States or its allies, including particularly war with Iraq, or military or trade disruptions impacting our suppliers or our customers or energy markets generally, may adversely impact our operations. As a result, there could be delays or losses in the delivery of supplies and raw materials to us, delays in our delivery of refined products, decreased sales of our products (especially sales to our customers that purchase jet fuel) and extension of time for payment of accounts receivable from our customers (especially our customers in the airline industry). Strategic targets such as energy-related assets (which could include refineries such as ours) may be at greater risk of future terrorist attacks than other targets in the United States. These occurrences could significantly impact energy prices, including prices for our crude oil and refined products, and have a material adverse impact on the margins from our refining and wholesale marketing operations. In addition, disruption or significant increases in energy prices could result in government-imposed price controls. Any one of, or a combination of, these occurrences could have a material adverse effect on our business.

If we are unable to maintain an adequate supply of feedstocks, our results of operations may be adversely affected.

We may not continue to have an adequate supply of feedstocks, primarily crude oil, available to our six refineries to sustain our current level of refining operations. If additional crude oil becomes necessary at one or more of our refineries, we intend to implement available alternatives that are most advantageous under then prevailing conditions. Implementation of some alternatives could require the consent or cooperation of third parties and other considerations beyond our control. In particular, the North Dakota refinery is landlocked and does not have a diversity of pipelines to allow us to transport crude oil to it. The North Dakota refinery, therefore, is completely dependent upon the delivery of crude oil through our crude oil pipeline system. If outside events cause an inadequate supply of crude oil, or if our crude oil pipeline system transports lower volumes of crude oil, our anticipated revenues could decrease. If we are unable to obtain supplemental crude oil volumes, or are only able to obtain these volumes at uneconomic prices, our results of operations could be adversely affected.

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.

Our Washington refinery receives all of its Canadian crude oil through pipelines operated by third parties. During 2002, we also delivered approximately 62,000 bpd of gasoline, diesel and jet fuel through third-party pipelines. Our Hawaii and Alaska refineries receive most of their crude oil and transport a substantial portion of refined products through ships and barges. Our Mid-Continent refineries receive substantially all of their crude oil and deliver substantially all of their products through pipelines. Our California refinery receives approximately half of its crude oil through pipelines and the balance through marine vessels. Substantially all of our California refinery's production is delivered through third-party pipelines, ships and barges. In addition to environmental risks discussed above, we could experience an interruption of supply or an increased cost to deliver refined products to market if the ability of the pipelines or vessels to transport crude oil or refined products is upset because of accidents, governmental regulation or third-party action. A prolonged upset of the ability of a pipeline or vessels to transport crude oil or product could have a material adverse effect on our business, financial condition and results of operations.

Our operating results are seasonal and generally are lower in the first and fourth quarters of the year.

Demand for gasoline is higher during the spring and summer months than during the winter months due to seasonal increases in highway traffic. As a result, our operating results for the first and fourth quarters are generally lower than for those in the second and third quarters.

ITEM 3. LEGAL PROCEEDINGS

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our common stock is listed under the symbol "TSO" on the New York Stock Exchange and the Pacific Exchange. The per share market price ranges for our common stock on the New York Stock Exchange during 2002 and 2001 are summarized below:

	2002		2001	
Quarters Ended	**High**	**Low**	**High**	**Low**
March 31	$\$15\frac{19}{64}$	$\$11\frac{1}{2}$	$\$14\frac{1}{2}$	$11
June 30	$\$14\frac{35}{64}$	$\$\ 5\frac{5}{8}$	$\$16\frac{1}{2}$	$\$11\frac{27}{32}$
September 30	$\$\ 7\frac{47}{64}$	$\$\ 2\frac{13}{32}$	$\$14\frac{15}{64}$	$\$\ 9\frac{45}{64}$
December 31	$\$\ 5\frac{13}{64}$	$\$\ 1\frac{15}{64}$	$\$13\frac{57}{64}$	$\$11\frac{29}{64}$

At February 28, 2003, there were approximately 2,650 holders of record of our 64,608,233 outstanding shares of common stock. We have not paid dividends on our common stock since 1986 and our Board of Directors has no present plans to pay dividends on our common stock. For information regarding restrictions on future dividend payments and stock repurchase program, see Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and Notes G and H of Notes to Consolidated Financial Statements in Item 8.

As discussed in Note H of Notes to Consolidated Financial Statements in Item 8, all of our Premium Income Equity Securities automatically converted into 10,350,000 shares of common stock on July 1, 2001. The final quarterly cash dividends on these securities were paid on July 2, 2001.

The 2003 Annual Meeting of Stockholders will be held at 8:00 A.M. Mountain time on Thursday, May 1, 2003, at the Four Seasons Hotel, 10600 East Crescent Moon Drive, Scottsdale, Arizona. Holders of Common Stock of record at the close of business on March 12, 2003 are entitled to notice of and to vote at the annual meeting.

The following table summarizes, as of December 31, 2002, certain information regarding equity compensation to our employees, officers, directors and other persons under our equity compensation plans.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in the Second Column)
Equity compensation plans approved by security holders ..	5,318,563	$11.76	1,418,614
Equity compensation plans not approved by security holders(a)	748,750	$10.35	50,500
Total	6,067,313	$11.59	1,469,114

(a) The Key Employee Stock Option Plan (the "1999 Plan") was approved by our board of directors in November 1999. The 1999 Plan provides for the granting of stock options to eligible persons we employ who are not our executive officers. Under the 1999 Plan, we may grant stock options to acquire a total of 800,000 shares. We may grant stock options at not less than the fair market value (as defined in the 1999 Plan) on the date the options are granted, and the stock options generally become exercisable after one year in 25 percent annual increments. The options expire ten years after the date of grant. Our board of directors may amend, terminate or suspend the 1999 Plan at any time.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth certain selected consolidated financial and operating data of Tesoro as of the end of and for each of the five years in the period ended December 31, 2002. The selected consolidated financial information presented below has been derived from our historical financial statements. Our financial results include the results of our California operations since mid-May 2002 and our Mid-Continent operations since September 2001. The following table should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and our Consolidated Financial Statements, including the Notes thereto, in Item 8.

	Years Ended December 31,				
	2002	2001	2000	1999	1998
	(Dollars in millions except per share amounts)				
Statement of Operations Data					
Total Revenues	$7,119	$5,182	$5,067	$3,000	$1,387
Earnings (Loss) from Continuing Operations, Net of Income Taxes(a)	$ (117)	$ 88	$ 73	$ 32	$ 8
Earnings (Loss) from Discontinued Operations, Net of Income Taxes(b)	—	—	—	43	(23)
Extraordinary Loss, Net of Income Taxes(c)	—	—	—	—	(4)
Net Earnings (Loss)	(117)	88	73	75	(19)
Preferred Dividend Requirements(d)	—	6	12	12	6
Net Earnings (Loss) Applicable to Common Stock	$ (117)	$ 82	$ 61	$ 63	$ (25)
Earnings (Loss) per Share:					
Continuing Operations —					
Basic	$(1.93)	$ 2.26	$ 1.96	$ 0.62	$ 0.05
Diluted	$(1.93)	$ 2.10	$ 1.75	$ 0.62	$ 0.05
Net Earnings (Loss) —					
Basic	$(1.93)	$ 2.26	$ 1.96	$ 1.94	$(0.86)
Diluted	$(1.93)	$ 2.10	$ 1.75	$ 1.92	$(0.86)
Weighted Shares Outstanding (millions):					
Basic	60.5	36.2	31.2	32.4	29.4
Diluted(d)(f)	60.5	41.9	41.8	32.8	29.9
Balance Sheet Data					
Current Assets(e)	$1,054	$ 878	$ 630	$ 612	$ 370
Property, Plant and Equipment, Net	$2,303	$1,522	$ 781	$ 732	$ 691
Net Assets of Discontinued Operations	$ —	$ —	$ —	$ —	$ 213
Total Assets	$3,759	$2,662	$1,544	$1,487	$1,406
Current Liabilities	$ 608	$ 539	$ 382	$ 322	$ 188
Total Debt and Other Obligations(e)(f)	$1,977	$1,147	$ 311	$ 418	$ 544
Stockholders' Equity(f)(g)	$ 888	$ 757	$ 670	$ 623	$ 559
Current Ratio	1.7:1	1.6:1	1.6:1	1.9:1	2.0:1
Working Capital	$ 446	$ 339	$ 248	$ 290	$ 182
Total Debt to Capitalization(e)(f)	69%	60%	32%	40%	49%
Common Stock Outstanding (millions of shares)(f)(g)	64.6	41.4	30.9	32.4	32.3
Book Value Per Common Share	$13.74	$18.28	$16.39	$14.14	$12.19

(table continued on following page)

	2002	2001	2000	1999	1998
	Years Ended December 31,				
	(Dollars in millions except per share amounts)				
Other Data					
Cash Flows From (Used In) —					
Operating Activities	$ 58	$ 214	$ 90	$ 113	$ 122
Investing Activities	(941)	(976)	(88)	166	(719)
Financing Activities	941	800	(130)	(149)	607
Increase (Decrease) in Cash and Cash Equivalents	$ 58	$ 38	$ (128)	$ 130	$ 10
Capital Expenditures(h) —					
Continuing operations	$ 204	$ 210	$ 94	$ 85	$ 50
Discontinued operations	—	—	—	56	135
Total capital expenditures	$ 204	$ 210	$ 94	$ 141	$ 185
Operating Data					
Refining Throughput (thousands of bpd)(i) —					
California	95	—	—	—	—
Pacific Northwest					
Washington	104	119	117	98	43
Alaska	53	50	48	49	58
Mid-Pacific					
Hawaii	82	87	84	87	48
Mid-Continent					
North Dakota	51	17	—	—	—
Utah	50	17	—	—	—
Total Refining Throughput	435	290	249	234	149
Refining Yield (thousands of bpd)(i) —					
Gasoline and gasoline blendstocks	204	111	95	93	51
Jet fuel	64	59	58	58	41
Diesel fuel	87	53	39	33	19
Heavy oils, residual products, internally produced fuel and other	95	75	65	60	43
Total Refining Yield	450	298	257	244	154
Product Sales (thousands of bpd)(i)(j)					
Gasoline and gasoline blendstocks	264	161	135	124	58
Jet fuel	94	81	76	76	46
Diesel fuel	115	73	54	47	24
Heavy oils, residual products and other	72	61	58	56	40
Total Product Sales	545	376	323	303	168
Retail Fuel Sales (millions of gallons)	790	396	215	199	157
Number of Retail Stations (end of period)	593	677	276	244	232

(a) In 2002, we incurred charges of $20 million primarily for bridge financing fees and integration costs associated with the acquisition of the California refinery ($12 million aftertax or $0.20 per share). In 2001, we incurred charges of $12 million for financing fees and integration costs, primarily associated with the acquisition of our Mid-Continent refineries ($7 million aftertax or $0.17 per share). In 1998, we incurred a pretax charge of $19 million for special incentive compensation ($12 million aftertax or $0.40 per share).

(b) In December 1999, we sold our oil and gas exploration and production operations and recorded an aftertax gain of $39 million from the sale of these operations. In 1998, these operations incurred pretax writedowns of oil and gas properties of $68 million ($43 million aftertax) and recognized pretax income from receipt of contingency funds of $21 million ($13 million aftertax).

(c) In 1998, extraordinary losses on debt extinguishments, net of income tax benefits, were $4 million ($0.15 per basic and diluted share).

(d) The assumed conversion of our Premium Income Equity Securities into 10.35 million shares of our common stock for 1999 and 1998 produced anti-dilutive results and therefore was not included in the diluted calculations of earnings per share. These securities automatically converted into shares of common stock in July 2001, which eliminated our $12 million annual preferred dividend requirement.

(e) At December 31, 2002, cash and cash equivalents included $16 million which was used to prepay term loans in January 2003, as required by our senior secured credit facility.

(f) During 2002, we issued $450 million in principal amount of 9⅝% senior subordinated notes due 2012 and two 10-year junior subordinated notes with face amounts totaling $150 million, completed a public offering of 23 million shares and amended and restated our senior secured credit facility, primarily to fund the acquisition of the California refinery assets. In conjunction with the acquisitions of the Mid-Continent refineries, we issued $215 million in principal amount of 9⅝% senior subordinated notes due 2008 and entered into a senior secured credit facility in 2001. In conjunction with acquisitions in 1998, we refinanced our then existing indebtedness and issued 9% senior subordinated notes due 2008 and additional equity securities, including common stock and Premium Income Equity Securities that are included in stockholders' equity.

(g) We have not paid dividends on our common stock since 1986.

(h) Capital expenditures exclude amounts to fund acquisitions in the Refining segment and Retail segment in 2002, 2001 and 1998 and exclude amounts for refinery turnaround spending and other major maintenance.

(i) Volumes for 2002 include amounts from the California refinery since we acquired it on May 17, 2002, averaged over 365 days. Throughput and yield for the California refinery averaged over the 229 days of operation that we owned it were 150,800 bpd and 160,000 bpd, respectively. Volumes for 2001 include amounts from the Mid-Continent operations since we acquired them on September 6, 2001, averaged over 365 days. Throughput and yield for these refineries averaged over the 117 days that we owned them in 2001 were 105,000 and 108,700 bpd, respectively. Volumes for 1998 include amounts from the Hawaii operations (acquired in May 1998) and the Washington refinery (acquired in August 1998) since their dates of acquisition, averaged over 365 days.

(j) Sources of total product sales in our Refining segment include products manufactured at the refineries, products from inventory balances and products purchased from third parties for resale.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Those statements in this section that are not historical in nature should be deemed forward-looking statements that are inherently uncertain. See "Forward-Looking Statements" on page 53 and "Risk Factors" on page 19 for a discussion of the factors that could cause actual results to differ materially from those projected in these statements.

BUSINESS OVERVIEW

Our earnings, cash flows from operations and liquidity depend upon many factors, including producing and selling refined products at margins above fixed and variable expenses. The prices of crude oil and refined products have fluctuated substantially in our markets. Our operating results can be significantly influenced by the timing of changes in crude oil costs and how quickly refined product prices adjust to reflect these changes. These price fluctuations depend on numerous factors beyond our control, including the demand for crude oil, gasoline and other refined products, which is subject to, among other things, changes in the economy and the level of foreign and domestic production of crude oil and refined products, worldwide political conditions, threatened or actual terrorist incidents or acts of war, availability of crude oil and refined product imports, the infrastructure to transport crude oil and refined products, weather conditions, earthquakes and other natural disasters, seasonal variation, government regulations and local factors, including market conditions and the level of operations of other refineries in our markets. As a result of these factors, margin fluctuations during any reporting period can have a significant impact on our results of operations, cash flows, liquidity and financial position.

During 2002, the refining industry in our market areas experienced the lowest refined product margins since 1998. A warm winter in the Northeast depressed distillate margins throughout the country and jet fuel demand declined dramatically following the events of September 11, 2001. This in turn led U.S. and foreign refiners to reduce distillate and jet fuel production with a corresponding increase in gasoline output. The resulting levels of gasoline produced exceeded gasoline demand increases, leading to lower gasoline margins. The industry experienced rapidly rising crude oil prices due to tensions with Iraq during 2002 and political instability in Venezuela during the 2002 fourth quarter. These factors led to industry refining margins in our market areas that were significantly below our five-year average (January 1, 1998 through December 31, 2002). We determine our "five-year average" by comparing gasoline, diesel and jet fuel prices to crude oil prices in our market areas, with volumes weighted according to our typical refinery yields. We experienced net losses in each of the 2002 quarters resulting from weak industry margins and additional interest and financing costs related to our acquisitions of the California refinery in May 2002 and the Mid-Continent refineries in September 2001. In connection with these acquisitions, our total debt increased by approximately $1.7 billion from June 30, 2001 to June 30, 2002. In addition, the ratings of our senior secured credit facility and senior subordinated notes were downgraded. We have also experienced a tightening of the trade credit we receive, which has required us to issue an increased amount of letters of credit and make early payments and prepayments to certain suppliers.

Despite the weak margin environment, we generated cash flows from operations of $58 million in 2002 and reduced term debt by $140 million (including a $16.3 million prepayment in January 2003) following the acquisition of the California refinery by selling over $200 million in assets, eliminating or deferring capital expenditures, reducing expenses, achieving operating synergies and reducing inventories. As of December 31, 2002, we had $110 million in cash, no borrowings under the revolving credit facility and, with $60 million in letters of credit outstanding, had total unused credit available of $165 million and a total debt to capitalization ratio of 69%.

We believe the industry conditions that led to low margins in 2002 have improved, and if this improvement continues and margins remain at or near the five-year average for the remainder of 2003, we believe we will comply with the financial covenants of our senior secured credit facility in 2003. Industry margins in 2003 in most of our market areas have averaged above our five-year average (as described above). The winter in the Northeast has been extremely cold in 2003, increasing demand and margins for distillates throughout the country. Jet fuel demand has slowly improved and now approaches pre-September 11, 2001 levels. Gasoline supply is expected to tighten due to numerous factors, including changes in gasoline specifications and the voluntary phase-out of MTBE in California.

However, if industry margins in our market areas drop below our five-year average for any substantial period of time or if we find it necessary to borrow the remaining available amounts under our senior secured credit facility for working capital purposes, including to support trade credit requirements, we will likely need to amend our senior secured credit facility because we may not meet certain financial covenant tests during the remainder of 2003. In addition, our credit ratings may be further reduced and our trade credit may be further tightened. We believe that we will be able to amend our senior secured credit facility or obtain covenant waivers if necessary; however, we cannot provide any assurances that we will be able to obtain such an amendment or waiver on terms and conditions acceptable to us or at all. See also "Risk Factors" in Items 1 and 2 beginning on page 19.

To better enable us to withstand a low margin environment similar to that experienced in 2002, our 2003 goals include the further reduction of ongoing cash expenses and elimination or deferral of capital expenditures. Assuming these initiatives are realized and, if necessary, we are able to amend our senior secured credit facility or obtain covenant waivers, we believe cash flow from operations, amounts available under our senior secured credit facility and available cash will be adequate to meet our anticipated requirements in 2003 for working capital, capital expenditures and scheduled payments of principal and interest on our indebtedness.

In addition, we are pursuing discussions regarding possible financing alternatives to replace our senior secured credit facility. If we pursue such alternatives, we intend to seek a debt structure designed (1) to increase our capacity to borrow for working capital needs, (2) to allow us to issue letters of credit instead of making early payments and prepayments to certain suppliers and apply the funds that would otherwise have been used for those payments and prepayments to repay debt and (3) to substantially modify the financial covenants we have under our existing senior secured credit facility. However, we cannot provide any assurances that such financing alternatives will be available on terms and conditions acceptable to us or at all.

BUSINESS STRATEGY

Our strategy is to create a geographically-focused, value-added refining and marketing business that has (i) economies of scale, (ii) a low-cost structure, (iii) superior management information systems and (iv) outstanding employees focused on business excellence and that seeks to provide stockholders with competitive returns in any economic environment. Our immediate focus is to reduce our level of debt through a combination of cash flow from operations, cost savings and revenue enhancements.

Debt Reduction

In June 2002, we announced our goal to reduce debt by $500 million by the end of 2003. As reflected in our operating results, we experienced a weak margin environment in 2002 which negatively affected our debt reduction plans. Nevertheless, we have repaid $140 million of term loan debt since May 2002 (including a $16.3 million prepayment in January 2003). The primary initiatives for 2002 were (i) asset sales, (ii) capital expenditure reductions, (iii) achievement of system-wide synergies following our acquisition of refinery assets in California, (iv) a working capital optimization program and (v) a cost reduction and refinery improvement program.

For 2003, we continue to pursue our goal to further reduce debt through positive operating cash flows and cash conservation measures based on the following strategic initiatives: (i) a cost reduction and refinery improvement program, (ii) elimination or deferral of capital expenditures and refinery turnaround spending, (iii) achievement of system-wide synergies from the acquisition of our California refinery and (iv) asset sales.

Asset Sales

Asset sales provided the largest contribution to our debt reduction goal in 2002. We identified certain non-core asset groups to be evaluated to meet the goal of raising $200 million, which initially included our marine services operations, the crude oil and product pipeline systems and associated terminals around the North Dakota refinery, and selected retail sites.

In December 2002, we sold our product pipeline extending from Mandan, North Dakota to Minneapolis, Minnesota and terminals in Jamestown, North Dakota and Moorhead, Sauk Centre and Minneapolis/ St. Paul, Minnesota for approximately $100 million in cash; we completed the sale of 70 retail stations in northern California (that we had acquired with the California refinery) for approximately $66 million in cash; and we completed a sale/lease-back transaction for 30 of our retail sites located in Alaska, Hawaii, Idaho and Utah for cash proceeds of approximately $40 million. These and other miscellaneous asset sales provided aggregate net proceeds totaling approximately $207 million. As required under the senior secured credit facility, we used 50% of the aggregate net proceeds to prepay term loans ($87.5 million in December 2002 and $16.3 million in January 2003). We plan to dispose of an additional $20 million of non-core assets in 2003.

Given the limited divestiture opportunities for our marine services operations on the U.S. Gulf Coast, we plan to integrate this business with our wholesale marketing and terminal operations during 2003. Our goal is to increase the overall profitability of this operation as we optimize it within our existing organization.

We have explored alternatives for our crude oil pipeline in North Dakota. Our objective was to sell this asset while preserving the security of supply and quality standards of our crude source for our North Dakota refinery. We have considered several potential sale structures but have not identified a transaction that meets our objectives. Therefore, we are no longer pursuing a divestiture of this asset.

Reductions in Capital Expenditures and Refinery Turnaround Spending

Another initiative is to reduce capital expenditures and refinery turnaround spending by a combined $70 million during 2002 and 2003. We spent $243.5 million in 2002, which included $54 million in the fourth quarter. Total capital and turnaround spending in 2002 was below the $250 million that we targeted in June 2002 following the acquisition of the California refinery. Our current plan is to spend approximately $164 million in 2003, including approximately $17 million to complete the CARB III project at the California refinery in the first quarter and approximately $42 million primarily for major turnarounds at three of our refineries.

Achievement of Synergies

We also are focusing on pursuing new synergies from our refinery system following the acquisition of the California refinery. During 2002, we achieved approximately $12 million in synergies, surpassing our previously announced goal of $10 million. During the California refinery turnaround in June 2002, we were able to achieve benefits that otherwise would have been unavailable without the California refinery. For example, we were able to upgrade the value of intermediate feedstock produced by our other refineries through supply to our California refinery during the turnaround. In addition, we have been able to upgrade unfinished gasoline components from elsewhere in our refinery system by blending them into finished gasoline. We believe that we will achieve the targeted annual system synergies of $25 million by the end of 2003, largely due to the benefits from owning the California refinery for a full year.

Working Capital Optimization

During 2002, one of our initiatives was to optimize our working capital. Since we began this initiative in June 2002, we reduced our crude oil and product inventories by approximately 5.5 million barrels to 17.8 million barrels at the end of December 2002. The value of this inventory reduction exceeded our goal to reduce working capital by $50 million by year-end 2002. We are projecting this level of inventory at year-end 2003; however, due to seasonal factors, we expect inventory increases at various times during the year. Our effort to reduce our working capital in 2002 was partially offset by the 30% to 40% increase in crude oil prices during the fourth quarter and a shortening of our normal payment terms to creditors.

Cost Reduction and Refinery Improvement Program

Our final initiative is to realize $75 million of operating income improvements through cost reductions and refining improvements that do not require significant capital investments. Our goal was to achieve $10 million of the operating improvements by the end of 2002 and $65 million by the end of 2003. During the 2002 third and fourth quarters, we initiated programs to consolidate our marketing organization, eliminate non-essential travel and reduce contract labor in both operations and administration. In addition, we made other reductions in manufacturing costs, but they were offset by higher utility expenses. Through these programs and other efficiencies, we achieved our goal of $10 million in operating improvements during 2002. In 2003, we expect to further reduce administrative, marketing and operating expenses through reorganization and related employee cost savings, achieving economies in refinery maintenance and purchasing and cost savings from the continued rationalization of our retail assets. See Note O of Notes to Consolidated Financial Statements in Item 8 for information related to certain charges for enhanced retirement plan benefits and other employee costs to be incurred in the first quarter of 2003.

Refining Improvements

CARB III Project

We anticipate that the CARB III project will increase our capacity to produce CARB gasoline at the California refinery by up to 20,000 bpd or approximately 30%. This project will enable us to comply with California regulations to phase out the use of the oxygenate known as MTBE, currently expected to be effective on January 1, 2004. We spent approximately $60 million through December 31, 2002, and we expect to spend an additional $17 million to complete the project in the first quarter of 2003.

Heavy Oil Conversion Project

We completed a heavy oil conversion project at our Washington refinery in the 2002 first quarter, which enables us to process a larger proportion of lower-cost heavy crude oils, to manufacture a larger proportion of higher-value gasoline and to reduce production of lower-value heavy products. The upgraded FCC unit, the final major component of the heavy oil conversion project, was fully operational at the end of the first quarter of 2002. The total cost of the project was approximately $121 million, of which $24 million was spent in 2002.

RESULTS OF OPERATIONS

Summary

Our net loss for the year 2002 was $117 million ($1.93 net loss per basic and diluted share) compared with net earnings of $88 million ($2.26 per basic share and $2.10 per diluted share) for 2001. The net loss for 2002 was primarily the result of weak margins in each of our operating segments and additional interest and financing costs related to acquisitions in the second half of 2001 and in May 2002. Charges for bridge financing fees and integration costs, primarily associated with the acquisition of the California refinery, totaled approximately $12 million aftertax, or $0.20 per share, in 2002. Our 2002 results also included losses on asset sales and impairment of goodwill, which totaled approximately $5 million aftertax, or $0.08 per share. In 2001, we incurred approximately $7 million aftertax, or $0.17 per share, for financing fees and integration costs, primarily associated with the acquisition of our Mid-Continent refineries.

Our net earnings for the year 2001 were $88 million ($2.26 per basic share or $2.10 per diluted share), an increase of 20% compared to net earnings of $73 million ($1.96 per basic share or $1.75 per diluted share) in 2000. The earnings improvement in 2001 was primarily a result of increased refining throughput, improved operating performance and incremental operating income from acquisitions. This improvement was partially offset by expenses related to acquisition financing and integration.

A discussion and analysis of the factors contributing to our results of operations are presented below. The accompanying Consolidated Financial Statements and related Notes, together with the following information, are intended to provide investors with a reasonable basis for assessing our operations, but should not serve as the only criteria for predicting our future performance.

Refining Segment

	2002	2001	2000
	(Dollars in millions except per barrel amounts)		
Revenues			
Refined products (a)	$6,426	$4,603	$4,499
Crude oil resales and other	335	248	289
Total Revenues	$6,761	$4,851	$4,788
Total Refining Throughput (thousand bpd) (b)	435	290	249
Refining Margin ($/throughput barrel) (c) (d)			
California (b)			
Gross refining margin	$ 6.41	$ —	$ —
Manufacturing cost before depreciation and amortization	$ 4.17	$ —	$ —
Pacific Northwest			
Gross refining margin	$ 4.09	$ 6.07	$ 6.93
Manufacturing cost before depreciation and amortization	$ 2.05	$ 1.89	$ 1.99
Mid-Pacific			
Gross refining margin	$ 2.85	$ 4.96	$ 4.14
Manufacturing cost before depreciation and amortization	$ 1.39	$ 1.27	$ 1.29
Mid-Continent (b)			
Gross refining margin	$ 4.17	$ 7.25	$ —
Manufacturing cost before depreciation and amortization	$ 2.22	$ 2.07	$ —
Total			
Gross refining margin	$ 4.38	$ 5.87	$ 5.98
Manufacturing cost before depreciation and amortization	$ 2.43	$ 1.72	$ 1.75
Segment Operating Income (c)			
Gross refining margin (after inventory changes) (e)	$ 699	$ 598	$ 533
Expenses —			
Manufacturing costs (d)	386	182	160
Other operating expenses	104	101	91
Selling, general and administrative	32	26	33
Depreciation and amortization (f)	104	63	58
Segment Operating Income	$ 73	$ 226	$ 191
Product Sales (thousand bpd) (a) (g)			
Gasoline and gasoline blendstocks	264	161	135
Jet fuel	94	81	76
Diesel fuel	115	73	54
Heavy oils, residual products and other	72	61	58
Total Product Sales	545	376	323

	2002	2001	2000
	(Dollars in millions except per barrel amounts)		
Product Sales Margin ($/barrel) (g)			
Average sales price	$32.25	$33.50	$38.12
Average costs of sales	28.75	29.17	33.70
Gross Sales Margin	$ 3.50	$ 4.33	$ 4.42

(a) Includes intersegment sales to our Retail segment, at prices which approximate market, of $826 million, $334 million and $213 million in 2002, 2001 and 2000, respectively.

(b) Volumes for 2002 include amounts for the California refinery since we acquired it on May 17, 2002, averaged over 365 days. Throughput for the California refinery averaged over the 229 days of operation was 151 thousand bpd. Volumes for 2001 include amounts for the Mid-Continent refineries since we acquired them on September 6, 2001 averaged over 365 days. Throughput for the Mid-Continent refineries averaged over the 117 days of operation was 105 thousand bpd.

(c) Certain previously reported amounts have been reclassified to conform to the 2002 presentation. The value of internally-produced fuel has been reclassified from Manufacturing Costs and is shown as a reduction in Gross Refining Margin. The value of internally-produced fuel amounted to $1.09 per barrel, $1.18 per barrel and $0.86 per barrel for 2002, 2001 and 2000, respectively, for the total refining segment. In addition, amortization of refinery turnaround and major maintenance costs was reclassified from Manufacturing Costs to Depreciation and Amortization. Major maintenance amortization amounted to $0.16 per barrel, $0.20 per barrel and $0.24 per barrel for 2002, 2001 and 2000, respectively, for the total refining segment. Management uses gross refining margin per barrel to compare profitability to other companies in the industry. Gross refining margin per barrel is calculated by dividing gross refining margin by annual total refining throughput. Gross refining margin per barrel may not be comparable to similarly titled measures used by other entities.

(d) Manufacturing costs are primarily operating cash costs directly associated with the manufacturing process and as described in (c) above, exclude non-cash amortization of refinery turnaround and major maintenance costs and the value of internally-produced fuel. Management uses manufacturing costs per barrel to evaluate the efficiency of refinery operations. Manufacturing costs per barrel may not be comparable to similarly titled measures used by other entities.

(e) Our gross refining margin is revenues less cost of refining feedstock and purchased products. Gross refining margin approximates total Refining segment throughput times gross refining margin per barrel, adjusted for changes in refined product inventory due to selling a volume and mix of product that is different than actual volumes manufactured. Also includes the effect of intersegment sales to the Retail segment at prices which approximate market.

(f) Includes manufacturing depreciation per throughput barrel of approximately $0.40, $0.28 and $0.26 for 2002, 2001 and 2000, respectively. Also includes amortization of major maintenance costs of $0.16 per barrel, $0.20 per barrel and $0.24 per barrel for the years ended 2002, 2001 and 2000, respectively.

(g) Sources of total product sales included products manufactured at the refineries and products purchased from third parties. Total product sales margin included margins on sales of manufactured and purchased products and the effects of inventory changes.

2002 Compared to 2001. Operating income from our Refining segment was $73 million in 2002 compared to $226 million in 2001. Our results for 2002 and 2001 included amounts from acquired operations since the dates of acquisition. We acquired the Mid-Continent operations in September 2001 and the California refinery in mid-May 2002. The acquired California operations contributed approximately $37 million to our Refining operating income during 2002. Operating income for the Mid-Continent operations increased to $34 million in 2002 from $31 million in 2001 due to the full year of operation largely offset by weaker refined product margins.

The $153 million decrease in our operating income was primarily due to weak refined product margins in 2002. Margins began to decline in the fourth quarter of 2001 and remained low throughout 2002. Our total refining gross margins averaged $4.38 per barrel, a 25% decrease from 2001, reflecting lower margins in all of our comparable regions partly offset by California's margin contribution. The gross margins on a per-barrel basis in our Pacific Northwest, Mid-Pacific and Mid-Continent regions declined 33%, 43% and 42%, respectively, compared to 2001. Industry margins declined primarily due to above average inventory levels for finished products, rising crude oil prices and increased competition from product imports. The industry experienced rapidly rising crude oil prices due to tensions with Iraq during 2002 and political instability in Venezuela during the 2002 fourth quarter. Reduced jet fuel demand and weak economic conditions in the United States and abroad impacted overall industry inventory levels and margins for distillates. Gasoline demand remained strong during 2002 and trended higher than the 2001 level. The increased demand, however, was met with high industry gasoline production levels and increased competition from product imports. Our margins were also negatively impacted by the tightening of the price differential between light crude oil and heavy crude oil. This primarily affected our Pacific Northwest and California regions.

Our operating income in 2002 was also impacted negatively by the scheduled turnarounds at our Washington and California refineries in the first and second quarters of 2002, respectively, and unscheduled downtime at our Washington and Utah refineries in the first quarter of 2002. During the Washington refinery turnaround, we completed the heavy oil conversion project, which was fully operational in March 2002. While the heavy oil conversion project contributed to our segment operating income during the last nine months of 2002, the contribution was less than our expectation due to the tightening of the light to heavy crude price differential and weak refining margins.

On an aggregate basis, our total gross refining margin increased 17% from 2001 to $699 million in 2002, reflecting throughput volumes from the Mid-Continent and California refineries, which added 162 thousand bpd to our total refining throughput in 2002 compared to 2001. Throughput rates were reduced by 7% at our other refineries to 239 thousand bpd in 2002 from 256 thousand bpd in 2001 in response to the weak margin environment in 2002.

Revenues from sales of refined products increased 40% to $6.4 billion in 2002, from $4.6 billion in 2001, due to increased sales volumes from the Mid-Continent and California refineries, partly offset by lower average product sales prices. Total product sales averaged 545 thousand bpd in 2002, an increase of 45% from 2001, while average product prices dropped 4% to $32.25 per barrel. The increase in other revenues was primarily due to higher crude oil resales which totaled $314 million in 2002 compared to $239 million in 2001. Costs of sales also increased primarily due to the additional throughput volumes from the Mid-Continent and California refineries. During the 2002 third quarter, we reduced certain inventory levels at our Mid-Continent refineries by approximately 900,000 barrels from the year-end 2001 level, resulting in the liquidation of applicable LIFO inventory quantities carried at lower costs. This reduction in LIFO inventory is part of our working capital management program and decreased costs of sales by approximately $5 million pretax in 2002.

Expenses, excluding depreciation, increased to $522 million in 2002, primarily due to additional expenses of approximately $219 million from the Mid-Continent and California refineries. Excluding these new operations, total expenses did not change significantly from 2001. Manufacturing cost per barrel for the California refinery is higher than our other refineries because of its increased complexity and product upgrading capabilities. Depreciation and amortization increased to $104 million, primarily due to additional depreciation and amortization of $38 million from the Mid-Continent and California refineries.

Several currently anticipated events will impact our financial results in 2003. Major maintenance turnarounds are scheduled at the Utah refinery in March 2003, the Alaska refinery in the second quarter of 2003 and the North Dakota refinery in the fourth quarter of 2003. We anticipate that the CARB III project at our California refinery will increase our capacity to produce CARB gasoline at the refinery by up to 20,000 bpd or approximately 30%. Subsequent to the sale of the products pipeline in December 2002, we have continued to distribute our products through the pipeline. We estimate that pipeline tariffs, partly offset by a decrease in depreciation, will reduce our annual operating income for the North Dakota refinery by approximately $11 million.

2001 Compared to 2000. Operating income for the Refining segment was $226 million in 2001, an 18% increase from 2000. Our Mid-Continent operations acquired in 2001 contributed approximately $31 million to segment operating income. The increase was also driven by stronger refined product margins and higher refinery throughput from our Mid-Pacific refinery and higher throughput levels at our Pacific Northwest refineries.

During the fourth quarter of 2001, however, market conditions caused significant erosion in industry refining margins. Our weakest market was the Pacific Northwest, where our actual gross refining margin in the 2001 fourth quarter averaged $4.57 per barrel, reducing this region's annual 2001 margin to $6.07 per barrel compared to $6.93 per barrel in 2000. For the full year, total gross refining margin per barrel remained relatively flat from 2000.

On an aggregate basis, our total gross refining margin increased 12% to $598 million in 2001 reflecting higher throughput volumes and contributions from the Mid-Continent operations. We increased refinery throughput 3%, or 7 thousand bpd, excluding the acquired operations, as compared to 2000. In addition, we were able to process a higher percentage of lower cost heavy crude oil, which represented 45% of refinery throughput in 2001, compared with 43% in 2000.

Revenues from sales of refined products in the Refining segment increased to $4.6 billion in 2001, from $4.5 billion in 2000, due to increased sales volumes largely offset by lower prices. Total product sales averaged 376 thousand bpd in 2001, an increase of 16% from 2000, while product prices dropped 12% to $33.50 pe barrel. The decrease in other revenues was primarily due to lower crude oil resales which totaled $239 millio in 2001 compared to $277 million in 2000. Costs of sales remained flat in 2001 compared with 2000, primar reflecting lower prices for feedstocks and product supply offset by higher throughput.

Expenses, excluding depreciation, increased by 9% to $309 million in 2001, primarily due to addit operating expenses from our acquired operations and increased throughput at our other refineries. Dep tion and amortization increased from $58 million to $63 million, primarily reflecting the acquisition Mid-Continent refinery in 2001.

Retail Segment

	2002	2001	2000
	(Dollars in millions except per gallon amounts)		
Revenues(a)			
Fuel	$ 920	$ 421	$ 250
Merchandise and other	132	70	55
Total Revenues	$1,052	$ 491	$ 305
Fuel Sales (millions of gallons)(a)	790	396	215
Fuel Margin ($/gallon)(a)(b)	$ 0.12	$0.22	$0.17
Merchandise Margin (in millions)(a)	$ 35	$ 20	$ 17
Merchandise Margin (percent of sales)(a)	27%	30%	32%
Average Number of Stations (during the year)(a)	679	406	260
Total Number of Stations (end of year)	593	677	276
Segment Operating Income (Loss)(a)			
Gross Margins			
Fuel(c)	$ 95	$ 87	$ 37
Merchandise and other non-fuel margin	40	22	19
Total gross margins	135	109	56
Expenses(a) —			
Operating expenses	99	53	46
Selling, general and administrative	31	20	5
Depreciation and amortization(a)	17	11	7
Segment Operating Income (Loss)(a)	$ (12)	$ 25	$ (2)

ludes 70 retail stations in northern California (which we had acquired with the California refinery in
2002) that we sold in December 2002 and 30 of our retail sites located in Alaska, Hawaii, Idaho and
which we sold and leased-back in December 2002.

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on calculations to compare profitability to other companies in the industry.

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2001 Compared to 2000. Operating income for the Refining segment was $226 million in 2001, an 18% increase from 2000. Our Mid-Continent operations acquired in 2001 contributed approximately $31 million to segment operating income. The increase was also driven by stronger refined product margins and higher refinery throughput from our Mid-Pacific refinery and higher throughput levels at our Pacific Northwest refineries.

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On an aggregate basis, our total gross refining margin increased 12% to $598 million in 2001 reflecting higher throughput volumes and contributions from the Mid-Continent operations. We increased refinery throughput 3%, or 7 thousand bpd, excluding the acquired operations, as compared to 2000. In addition, we were able to process a higher percentage of lower cost heavy crude oil, which represented 45% of refinery throughput in 2001, compared with 43% in 2000.

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Expenses, excluding depreciation, increased by 9% to $309 million in 2001, primarily due to additional operating expenses from our acquired operations and increased throughput at our other refineries. Depreciation and amortization increased from $58 million to $63 million, primarily reflecting the acquisition of the Mid-Continent refinery in 2001.

Retail Segment

	2002	2001	2000
	(Dollars in millions except per gallon amounts)		
Revenues(a)			
Fuel	$ 920	$ 421	$ 250
Merchandise and other	132	70	55
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Selling, general and administrative	31	20	5
Depreciation and amortization(a)	17	11	7
Segment Operating Income (Loss)(a)	$ (12)	$ 25	$ (2)

(a) Includes 70 retail stations in northern California (which we had acquired with the California refinery in May 2002) that we sold in December 2002 and 30 of our retail sites located in Alaska, Hawaii, Idaho and Utah which we sold and leased-back in December 2002.

(b) Fuel margin per gallon is calculated by dividing fuel gross margin by fuel sales. Fuel margin per gallon may not be comparable to similarly titled measures used by other entities. Management uses fuel margin per gallon calculations to compare profitability to other companies in the industry.

(c) Includes the effect of intersegment purchases from our Refining segment at prices which approximate market.

2002 Compared to 2001. The operating loss for our Retail segment was $12 million in 2002 compared to operating income of $25 million in 2001. Total gross margins increased 24% to $135 million in 2002 from $109 million in 2001 reflecting increased sales volume, offset largely by lower fuel margin per gallon. Fuel margin decreased to $0.12 per gallon in 2002 from $0.22 per gallon in 2001, reflecting continued competitive price pressures and changes in the geographic mix of our Retail sites. Total gallons sold increased to 790 million, reflecting the increase in average station count to 679 in 2002 from 406 in 2001. This increase in average station count was primarily due to the Mid-Continent operations acquired in September 2001, additional stations acquired in the Pacific Northwest in November 2001, and the 70 retail stations acquired with the California refinery assets in May 2002. These increases were partially offset by approximately 150 BP/Amoco jobber/dealer stations (included in the Mid-Continent acquisition) that did not rebrand to the Tesoro® brand name. This decision not to rebrand resulted in us no longer being those jobber/dealer stations' exclusive supplier under the terms of the acquisition agreement. The 70 California stations, which we sold in December 2002, contributed operating income of approximately $6 million during the period we owned them in 2002. In addition, in December 2002, we completed a sale/lease-back transaction for 30 of our retail sites located in Alaska, Hawaii, Idaho and Utah. The related lease expense will decrease operating income by approximately $2 million in 2003.

Revenues on fuel sales increased to $920 million in 2002, from $421 million in 2001, while merchandise and other revenues increased by 89% to $132 million. Merchandise margin decreased, however, as a percent of sales, reflecting changes in the mix of merchandise offerings. With our increased number of stations, expenses increased to $130 million and depreciation increased to $17 million in 2002.

We adopted a flat to modest growth strategy for our Retail segment that will focus on select jobber/dealer investments in certain of our markets. We do not expect to build any new retail stations in 2003.

2001 Compared to 2000. Operating income for our Retail segment increased to $25 million in 2001, compared to a loss of $2 million in 2000. The expansion of our Tesoro-operated and jobber/dealer network enabled us to increase revenues and profits in 2001. Our total gallons sold increased 84% to 396 million, while our fuel margin increased by 29% to $0.22 per gallon. Our average station count during 2001 of 406 represents a 56% increase from 260 in 2000.

Revenues on fuel sales grew to $421 million in 2001, a 68% increase from 2000, while merchandise and other revenues increased by 27% to $70 million. Merchandise margin, however, as a percent of sales decreased. With our increased number of stations, expenses increased 43% to $73 million and depreciation increased to $11 million in 2001.

Other

In addition to our Refining and Retail segments, we market and distribute petroleum products and provide logistical support services to the marine and offshore exploration and production industries operating in the Gulf of Mexico. Operating income from these operations decreased to $2 million in 2002 from $10 million in 2001 and 2000. Lower sales volumes and service revenues contributed to this decrease. This segment is largely dependent on the volume of offshore oil and gas drilling, workover, construction and seismic activity. The significant decline in industry drilling activity negatively impacted sales and operating income during 2002.

Selling, General and Administrative Expenses

Selling, general and administrative expenses of $133 million in 2002 increased from $104 million in 2001. The increase was due partially to higher expenses in the Refining and Retail segments associated with the purchases of refinery and marketing assets in the last half of 2001 and May 2002. Corporate expenses accounted for $12 million of the increase during 2002, resulting from higher acquisition and integration costs, employee costs and professional fees.

Selling, general and administrative expenses of $104 million in 2001 increased $19 million from $85 million in 2000. This increase was partially due to higher expenses in the Retail segment associated with the increased number of stations in 2001. Corporate expenses accounted for $14 million of the increase resulting largely from $6 million in acquisition and integration costs in 2001, as well as higher employee costs and professional fees.

During 2002, we initiated programs to consolidate our marketing organization, eliminate non-essential travel and reduce contract labor in both operations and administration. We expect to further reduce these expenses during 2003. We will incur certain charges for enhanced retirement plan benefits and other employee costs. The charge in the first quarter of 2003 could range from $12 million to $24 million pretax, depending on the number of employees electing enhanced retirement plan benefits (see Notes A and O of Notes to Consolidated Financial Statements in Item 8 for further information).

Loss on Asset Sales and Impairment

The loss on asset sales and impairment of $8 million in 2002 consisted primarily of losses on the sale of retail stations of $7 million and an impairment of Retail goodwill of $1 million (see Notes E and L of Notes to Consolidated Financial Statements in Item 8).

Interest and Financing Costs

Interest and financing costs, net of capitalized interest, were $166 million in 2002 compared to $53 million in 2001. The increase was primarily due to the additional debt we incurred in 2001 and 2002 in connection with our acquisitions of the Mid-Continent and California operations. We also expensed $13 million during the first six months of 2002 related to bridge and other financing fees for the acquisition of the California refinery.

Interest and financing costs, net of capitalized interest, were $53 million in 2001 compared to $33 million in 2000. This increase was primarily due to the additional debt we incurred in 2001 and to costs of approximately $6 million related to acquisition financing. Lower interest rates in 2001 partially mitigated the impact of the increased debt levels.

We estimate interest expense for 2003 will be approximately $190 million, reflecting $165 million of scheduled interest payments and $25 million primarily for amortization of deferred financing costs and debt discounts. The estimated interest does not reflect potential borrowings under our revolving credit facility, prepayments of debt or charges related to possible refinancing (see Note A of Notes to Consolidated Financial Statements in Item 8). At December 31, 2002, we had $35 million of deferred financing costs related to our senior secured credit facility. If we elect to replace or modify our senior secured credit facility, we may be required to write-off all or a portion of these deferred costs during the quarter in which we replace or modify the facility.

Income Tax Provision (Benefit)

The income tax benefit amounted to $64 million in 2002, which compares to an income tax provision of $59 million in 2001. The benefit resulted from the pretax losses for 2002. In 2002, we elected to carry back net operating losses to recover income taxes paid in previous years; however, the refund of those taxes resulted in the loss of certain tax credits. The expiration of these credits, along with other adjustments to our estimated liabilities, resulted in a reduced tax benefit of approximately $6 million.

The income tax provision of $59 million in 2001 increased 17%, as compared to 2000, primarily reflecting the increase in pretax earnings. The combined Federal and state effective income tax rate was approximately 40% in both 2001 and 2000.

CAPITAL RESOURCES AND LIQUIDITY

Overview

We operate in an environment where our liquidity and capital resources are impacted by changes in the price of crude oil and refined petroleum products, availability of trade credit, market uncertainty and a variety of additional factors beyond our control. These risks include, among others, the level of consumer product demand, weather conditions, fluctuations in seasonal demand, governmental regulations, worldwide political conditions and overall market and economic conditions. See "Business Overview" on page 30, "Forward-Looking Statements" on page 53 and "Risk Factors" on page 19 for further information related to risks and other factors. Our future capital expenditures, as well as borrowings under our senior secured credit facility and other sources of capital, will be affected by these conditions.

Our primary sources of liquidity have been cash flows from operations, issuance of equity and debt, borrowing availability under revolving lines of credit, and asset sales. We ended 2002 with $110 million of cash and cash equivalents on our balance sheet, and we had no borrowings under our revolving credit facility and $60 million in outstanding trade letters of credit. As previously described, we sold assets in the 2002 fourth quarter from which we received net proceeds totaling $207 million. Of this amount, $87.5 million was used to prepay term loans in December 2002. An additional $16.3 million was included in cash at December 31, 2002 and, subsequent to year-end, was used to prepay term debt. Because of the weakness in industry refinery margins during 2002 and economic uncertainty, we have experienced a tightening of the trade credit we receive. We are a significant purchaser of crude oil and other feedstocks in our market areas, which enables us to use various purchasing strategies, including open credit terms, early payments, netting agreements, and to a lesser extent, prepayments of invoices. Under current economic conditions and in light of the general uncertainty which surrounds our business, we cannot give assurance that the trade credit extended to us will not be further tightened. We believe that we will be able to continue to operate at current production levels considering current market conditions, through our management of working capital, capital expenditures, available borrowing capacity under our revolving credit facility, available lines of trade credit and operating cash flows. However, if credit extended to us were to significantly tighten or our margins were to return to levels significantly below the average levels for the last five years for an extended period of time, our business might not be able to generate sufficient cash flow to fund operations, capital expenditures and debt service.

Capitalization

Our capital structure at December 31, 2002 was comprised of the following (in millions):

Debt, including current maturities:	
Senior Secured Credit Facility — Tranche A Term Loan	$ 194
Senior Secured Credit Facility — Tranche B Term Loan	724
Senior Secured Credit Facility — Revolver	—
9⅝% Senior Subordinated Notes due 2012	450
9⅝% Senior Subordinated Notes due 2008	215
9% Senior Subordinated Notes due 2008	298
Junior subordinated notes	67
Other debt, primarily capital leases	29
Total debt	1,977
Common stockholders' equity	888
Total Capitalization	$2,865

At December 31, 2002, our debt to capitalization ratio was 69% compared with 60% at year-end 2001, primarily reflecting acquisition-related borrowings under our senior secured credit facility and the issuance of $450 million aggregate principal amount of 9⅝% senior subordinated notes due 2012, partially offset by net proceeds of $245 million from the issuance of 23 million shares of common stock in March 2002, prepayment of term loans of $87.5 million in December 2002 from asset sales proceeds and regularly scheduled payments of debt.

Our senior secured credit facility and senior subordinated notes impose various restrictions and covenants on us that could potentially limit our ability to respond to market conditions, to raise additional debt or equity capital, or to take advantage of business opportunities. Each of these obligations is guaranteed by substantially all of our active domestic subsidiaries.

Senior Secured Credit Facility

On May 17, 2002, we amended and restated our senior secured credit facility to increase the facility to $1.275 billion from $1.0 billion to partially fund the acquisition of the California refinery and retail assets. The terms and conditions of this credit facility were subsequently amended on September 30, 2002, to reflect modified financial tests. The amendment also, among other things, increased the amount of proceeds from asset sales or equity offerings that must be received and limits capital expenditures, both of which are consistent with our previously announced goals. The credit facility was further amended in December 2002, giving flexibility to the terms and the timing of the required proceeds from asset sales or equity offerings. Under the revised terms of the credit facility, we agreed to pay certain fees and to increase the interest rate on borrowings.

The credit facility currently consists of a five-year $225 million revolving credit facility (with a $150 million sublimit for letters of credit), a five-year tranche A term loan and a six-year tranche B term loan. As of December 31, 2002, we had no borrowings and $60 million in letters of credit outstanding under the revolving credit facility, resulting in a total unused credit available of $165 million. As of December 31, 2002, $194 million principal amount was outstanding under the tranche A term loan and $724 million principal amount was outstanding under the tranche B term loan. In addition to the credit facility, we have an uncommitted letter of credit line with a bank, under which no amounts were outstanding as of December 31, 2002.

The credit facility is guaranteed by substantially all of our active domestic subsidiaries and is secured by substantially all of our material present and future assets, as well as all material present and future assets of our domestic subsidiaries (with certain exceptions for pipeline, retail and marine services assets) and is additionally secured by a pledge of all of the stock of all current and future active domestic subsidiaries and 66% of the stock of our current and future foreign subsidiaries.

At December 31, 2002, interest rates were 6.77% on the tranche A term loan and 8.5% on the tranche B term loan. Borrowings bear interest at either a base rate (4.25% at December 31, 2002) or a eurodollar rate (1.77% at December 31, 2002), plus an applicable margin. From September 30, 2002 to March 31, 2004, the applicable margins on the tranche A term loan and the revolving credit facility will be 3% in the case of the base rate and 4% in the case of the eurodollar rate and will be 3.5% in the case of the base rate and 4.5% in the case of the eurodollar rate for the tranche B term loan. Additionally, the tranche B eurodollar rate is deemed to be no less than 3.0%. Subsequent to March 31, 2004, borrowing rates under the tranche A term loan and the revolving credit facility will vary in relation to our senior debt to EBITDA ratio. The credit facility interest rates also include an additional 1% interest rate on the tranche A term loan, tranche B term loan and revolving credit facility from September 30, 2002 to March 31, 2004 and thereafter until our debt-to-capital ratio falls to no greater than 0.55 to 1.00. The first additional interest payment is due September 30, 2003 and quarterly thereafter. We are also charged various fees and expenses in connection with the credit facility, including commitment fees and various letter of credit fees.

The credit facility requires us to meet certain financial covenants, some of which use a measure of cash flow called EBITDA, as defined in the credit facility. The financial covenants specify thresholds of the following ratios which use EBITDA: senior debt to EBITDA, EBITDA to fixed charges and EBITDA to interest expense. The initial calculations of these ratios are to be made when we issue our financial results for the quarter ending September 30, 2003, using the immediately preceding four quarters. In addition, the financial covenants set a maximum threshold for total debt to total capitalization ratio, as defined in the credit facility, each quarter-end commencing June 30, 2002. The credit facility requires a minimum cumulative consolidated EBITDA amount of $90 million and $270 million for the nine-month period ending March 31, 2003 and the twelve-month period ending June 30, 2003, respectively. The credit facility also requires a minimum consolidated quick ratio, as defined in the credit facility, each month-end beginning October 31, 2002 through June 30, 2003. The credit facility limits our capital expenditure and refinery turnaround spending to no more than $253.5 million in the year 2002, $237.5 million for the twelve-month period ending June 30, 2003 and $210 million in the calendar year 2003 and each year thereafter unless our debt-to-capital ratio falls below 0.58 to 1.00. Under the terms of our senior secured credit facility, we are not permitted to declare or pay cash dividends on our common stock or repurchase shares of our common stock through December 31, 2003. Beginning January 1, 2004, the terms allow for payment of cash dividends on our common stock and repurchase of shares of our common stock, not to exceed $15 million in any year. The credit facility contains other covenants and restrictions customary in credit arrangements of this kind. Noncompliance with the covenants constitutes an event of default and, if not cured by a waiver or amendment, would permit the lenders to accelerate the maturity of the credit facility, refuse to advance any additional funds under the credit facility and exercise the lenders' remedies under the credit facility.

We satisfied all of the financial covenants under the credit facility for the period ended December 31, 2002, as well as the requirement to complete asset sales resulting in net proceeds of at least $200 million prior to March 31, 2003. Of this amount, $87.5 million was used to prepay term loans in December 2002. An additional $16.3 million, included in cash at December 31, 2002, was used to prepay term loans in January 2003. Net proceeds from asset sales or equity offerings received in 2003 up to the date we issue financial results for the quarter ending September 30, 2003, are required to be applied in full to prepay the term loans.

We believe the industry conditions that led to low margins in 2002 have improved, which we believe will enable us to comply with the financial covenants of our senior secured credit facility for the remainder of the year. However, if industry margins in our market areas drop below the five-year average for any substantial period of time or if we find it necessary to borrow the remaining available amounts under our senior secured credit facility for working capital purposes, including to support trade credit requirements, we will likely need to amend our senior secured credit facility because we may not meet certain financial covenant tests during the remainder of 2003. In addition, our credit ratings may be further reduced and our trade credit may be further tightened. We believe that we will be able to amend our senior secured credit facility or obtain covenant waivers if necessary; however, we cannot provide any assurances that we will be able to obtain such an amendment or waiver on terms and conditions acceptable to us or at all. See also "Risk Factors" under Items 1 and 2 beginning on page 19.

In addition, we are pursuing discussions regarding possible financing alternatives to replace our senior secured credit facility. If we pursue such alternatives, we intend to seek a debt structure designed (1) to increase our capacity to borrow for working capital needs, (2) to allow us to issue letters of credit instead of making early payments and prepayments to certain suppliers and apply the funds that would otherwise have been used for those payments and prepayments to repay debt and (3) to substantially modify the financial covenants we have under our existing senior secured credit facility. However, we cannot provide any assurances that such financing alternatives will be available on terms and conditions acceptable to us or at all.

Senior Subordinated Notes

In April 2002, we issued $450 million principal amount of 9⅝% senior subordinated notes due April 1, 2012. The 9⅝% senior subordinated notes due 2012 have a ten-year maturity with no sinking fund requirements and are subject to optional redemption by us beginning in April 2007 at declining premiums. In addition, until April 1, 2005, we may redeem up to 35% of the principal amount at a redemption price of 109.625% with proceeds of certain equity issuances.

In November 2001, we issued $215 million principal amount of 9⅝% senior subordinated notes due November 1, 2008. The 9⅝% senior subordinated notes due 2008 have a seven-year maturity with no sinking fund requirements and are subject to optional redemption by us beginning in November 2005 at declining premiums. In addition, until November 1, 2004, we may redeem up to 35% of the principal amount at a redemption price of 109.625% with the net cash proceeds of one or more equity offerings.

Our 9% senior subordinated notes due 2008, Series B, were issued in 1998 at a principal amount of $300 million. These notes have a ten-year maturity without sinking fund requirements and are subject to optional redemption by us beginning in July 2003 at declining premiums.

The indentures for our senior subordinated notes contain covenants and restrictions which are customary for notes of this nature. These covenants and restrictions are less restrictive than those under the senior secured credit facility and limit, among other things, our ability to:

- pay dividends and other distributions with respect to our capital stock and purchase, redeem or retire our capital stock;
- incur additional indebtedness and issue preferred stock;
- enter into certain asset sales;
- enter into transactions with affiliates;
- incur liens on assets to secure certain debt;

- engage in certain business activities; and
- engage in certain merger or consolidations and transfers of assets.

The indentures also limit our subsidiaries' ability to create restrictions on making certain payments and distributions. The senior subordinated notes are guaranteed by substantially all of our active domestic subsidiaries.

Junior Subordinated Notes

In connection with our acquisition of the California refinery, we issued to the seller two ten-year junior subordinated notes with face amounts aggregating $150 million. The notes consist of: (i) a $100 million junior subordinated note, due July 2012, which is non-interest bearing through May 16, 2007 and carries a 7.5% interest rate thereafter, and (ii) a $50 million junior subordinated note, due July 2012, which is non-interest bearing through May 16, 2003 and bears interest at 7.47% from May 17, 2003 through May 16, 2007 and 7.5% thereafter. The two junior subordinated notes with face amounts of $100 million and $50 million were initially recorded at a combined present value of approximately $61 million, discounted at a rate of 15.625% and 14.375%, respectively. The discount is being amortized over the term of the notes.

Equity Offering

On March 6, 2002, we completed a public offering of 23 million shares of our common stock. The net proceeds from the stock offering of $245 million, after deducting underwriting fees and offering expenses, were used to partially fund the acquisition of the California refinery.

Cash Flow Summary

Components of our cash flows are set forth below (in millions):

	2002	2001	2000
Cash Flows From (Used In):			
Operating Activities	$ 58	$214	$ 90
Investing Activities	(941)	(976)	(88)
Financing Activities	941	800	(130)
Increase (Decrease) in Cash and Cash Equivalents	$ 58	$ 38	$(128)

Net cash from operating activities during 2002 totaled $58 million, compared to $214 million from operating activities in 2001. The decrease was primarily due to lower earnings before depreciation and amortization and higher expenditures for scheduled refinery turnarounds, partially offset by reduced working capital requirements and receipt of income tax refunds. Net cash used in investing activities of $941 million in 2002 included $932 million for the acquisition of the California refinery and $204 million for capital expenditures, partially offset by $207 million in proceeds from asset sales. Net cash from financing activities of $941 million in 2002 included net proceeds of $245 million from our equity offering, net proceeds of $441 million from our notes offering and borrowings of $425 million under the senior secured credit facility, partly offset by repayments of debt of $133 million and financing costs of $37 million. Gross borrowings and repayments under revolving credit lines amounted to $624 million during 2002. We had no outstanding borrowings under our revolving credit facility at December 31, 2002. Working capital totaled $446 million at December 31, 2002 compared to $340 million at year-end 2001, reflecting increases related to the acquisition of the California refinery, cash and income taxes receivable, partly offset by reductions in inventories.

Net cash from operating activities during 2001 totaled $214 million, compared to $90 million in 2000. The increase was primarily due to higher earnings before depreciation and amortization and lower working capital requirements associated with the decrease in feedstock and refined product prices at year-end 2001. This increase in cash flow was partially offset by an increase in receivables from the sales activity associated with our refinery assets in the Mid-Continent operations. Net cash used in investing activities of $976 million in 2001 included $783 million for acquisitions and $210 million for capital expenditures, partially offset by proceeds from asset sales. Net cash from financing activities of $800 million in 2001 included net borrowings of $625 million under the senior secured credit facility and net proceeds of $210 million from our notes offering, partly offset by financing costs of $21 million and preferred dividend payments of $9 million. The preferred stock was converted to common stock in July 2001, eliminating our annual $12 million preferred dividend requirement. Gross borrowings and repayments under revolving credit lines and interim facilities amounted to $958 million during 2001. We had no outstanding borrowings under our revolving credit facility at December 31, 2001.

Net cash from operating activities during 2000 totaled $90 million. Operations provided cash flows from earnings before depreciation and amortization and other non-cash charges, partially offset by increased working capital requirements. During 2000, working capital requirements increased due to higher receivables and inventories reflecting higher prices for refinery feedstocks and products, as well as an increase in inventory volumes. Net cash used in investing activities of $88 million in 2000 included capital expenditures of $94 million, partly offset by proceeds from sales of assets. Net cash used in financing activities of $130 million in 2000 included repayments of debt totaling $106 million, repurchase of treasury stock of $15 million and payments of dividends on preferred stock of $9 million. We had no outstanding borrowings under revolving credit lines at December 31, 2000. Gross borrowings and repayments under revolving credit lines amounted to $866 million during 2000.

Historical EBITDA

EBITDA represents earnings before interest and financing costs, interest income, income taxes, and depreciation and amortization. EBITDA is presented herein because it enhances an investor's understanding of our ability to satisfy principal and interest obligations with respect to our indebtedness and to use cash for other purposes, including capital expenditures. EBITDA is also used for internal analysis and as a basis for several financial covenants. EBITDA should not be considered as an alternative to net earnings (loss), earnings (loss) before income taxes, cash flows from operating activities or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States ("U.S. GAAP"). EBITDA may not be comparable to similarly titled measures used by other entities. Our EBITDA for the years ended December 31, 2002, 2001 and 2000 were as follows (in millions):

	2002	2001	2000
Net Earnings (Loss)	$(117.0)	$ 88.0	$ 73.3
Add Income Tax Provision (Benefit)	(64.3)	58.9	50.2
Add Interest and Financing Costs	166.1	52.8	32.7
Less Interest Income	(3.5)	(1.0)	(2.8)
Operating Income (Loss)	(18.7)	198.7	153.4
Add Depreciation and Amortization	130.7	79.9	69.3
EBITDA	$ 112.0	$278.6	$222.7

Our EBITDA for the 2002 quarters were as follows (in millions):

	2002 Quarters			
	First	Second	Third	Fourth
Net Earnings (Loss)	$(55.6)	$(17.9)	$(15.8)	$(27.7)
Add Income Tax Provision (Benefit)	(37.2)	(11.9)	(8.0)	(7.2)
Add Interest and Financing Costs	30.3	41.6	43.6	50.6
Less Interest Income	(0.7)	(2.1)	(0.4)	(0.3)
Operating Income (Loss)	(63.2)	9.7	19.4	15.4
Add Depreciation and Amortization	25.2	29.5	38.2	37.8
EBITDA	$(38.0)	$ 39.2	$ 57.6	$ 53.2

Historical EBITDA as presented above is different than EBITDA as defined under our senior secured credit facility. The primary differences are non-cash postretirement benefit costs and loss on asset sales and impairment, which are added to net earnings (loss) under the senior secured credit facility EBITDA calculations.

Capital Expenditures and Refinery Turnaround Spending

Our capital expenditures and refinery turnaround spending totaled $243.5 million during 2002, as discussed below.

Capital Expenditures

During 2002, our capital expenditures (excluding refinery turnaround and other major maintenance costs) totaled $204 million, which included $24 million for completion of the heavy oil conversion project at our Washington refinery and $41 million for retail marketing programs. In addition, we spent approximately $77 million at our California refinery, including $60 million for a project to meet CARB III gasoline production requirements and $9 million to complete a nitrogen oxide emissions control project. Other capital spending was primarily for various refinery improvements and environmental requirements.

We reduced our 2003 capital spending plan in response to the weaker refining and retail margin environment. Our senior secured credit facility limits our total capital expenditures and refinery turnaround spending to no more than $237.5 million for the twelve-month period ending June 30, 2003 and $210 million for the year 2003. We have deferred our spending plans for certain discretionary projects while maintaining spending to meet environmental, safety, regulatory and other operational requirements. Currently, we have adopted a flat to modest growth strategy for the Retail segment that will focus on jobber investments in selected markets. Therefore, we do not expect to build any new retail sites in 2003.

Our current capital expenditure plan includes approximately $122 million in 2003 (excluding refinery turnaround and other major maintenance costs of approximately $42 million). The capital budget for the Refining segment is $99 million, including $17 million for the completion of the CARB III project, $10 million for other clean air and fuel projects, and other projects totaling $72 million. Our Retail capital budget is $3 million for 2003. We expect to fund the 2003 capital spending program primarily from operating cash flows, including benefits from cost reduction programs.

Refinery Turnaround and Other Major Maintenance

During 2002, we spent $40 million for refinery turnaround and other major maintenance, including $15 million for our scheduled turnaround of certain processing units at our California refinery in the second quarter of 2002 and $19 million for the completion of a scheduled turnaround of the Washington refinery in the first quarter of 2002. Amortization of refinery turnaround and other major maintenance costs totaled $27 million in 2002. We expect to spend approximately $42 million, primarily for major turnarounds at three of our refineries in 2003.

We estimate our annual spending for refinery turnarounds and other major maintenance to be as follows (in millions):

	2003	2004	2005	2006	2007
Refinery					
California	$ 5	$43	$41	$28	$48
Washington	2	8	3	36	7
Alaska	11	—	11	—	11
Hawaii	1	13	1	—	—
North Dakota	16	—	1	—	—
Utah	7	—	10	4	—
Total	$42	$64	$67	$68	$66

Long-Term Commitments

Contractual Commitments

We have numerous contractual commitments for purchases of goods and services arising in the ordinary course of business, debt service requirements and lease commitments (see Notes G and Q to Consolidated Financial Statements in Item 8). The following table summarizes these future commitments at December 31, 2002 (in millions):

	2003(a)	2004	2005	2006	2007	Beyond 2007
Debt	$ 70	$ 54	$ 54	$ 65	$684	$1,135
Ship Charters	30	26	27	28	28	72
Other Operating Leases	37	30	24	20	19	143
Other Commitments	26	25	14	14	14	37
Total Contractual Cash Commitments	$163	$135	$119	$127	$745	$1,387

(a) Debt includes $16 million paid in January 2003 from asset sales completed in December 2002.

In addition to the above commitments, we have a power supply agreement at our California refinery which requires minimum payments that vary, based on market prices for electricity, over the next 10 years. We also anticipate we will continue to make annual base payments of approximately $6 million from 2004 to 2010 for an MTBE facility located at our California refinery.

We lease our corporate headquarters from a limited partnership in which we own a 50% limited interest. The initial term of the lease is through 2014 with two five-year renewal options. Lease payments and operating costs paid to the partnership totaled $2.1 million, $2.5 million and $1.8 million in 2002, 2001 and 2000, respectively, and our future commitments are included in operating leases in the table above. We account for our interest in the partnership using the equity method of accounting. As such, the partnership's assets, primarily land and buildings, totaling approximately $17 million and debt of approximately $13 million are not included in our Consolidated Financial Statements in Item 8.

Clean Fuels and Clean Air Capital

In February 2000, the EPA finalized new regulations pursuant to the Clean Air Act requiring reduction in the sulfur content in gasoline beginning January 1, 2004. To meet the revised gasoline standard, we currently estimate we will make capital improvements of approximately $37 million through 2006 and an additional $15 million thereafter. This will permit all of our refineries to produce gasoline meeting the limits imposed by the EPA.

In January 2001, the EPA also promulgated new regulations, pursuant to the Clean Air Act requiring a reduction in the sulfur content in diesel fuel manufactured for on-road consumption. In general, the new diesel fuel standards will become effective on June 1, 2006. Based on our latest engineering estimates, we expect to spend approximately $55 million in capital improvements through 2007 to meet these new requirements. These expenditures, however, do not include our Alaska refinery where we have limited demand for low sulfur diesel which presently does not justify the capital investment. We expect to meet this demand from other sources.

We expect to spend approximately $44 million in additional capital improvements through 2006 to comply with the Refinery MACT II regulations promulgated in April 2002. The Refinery MACT II regulations will require new emission controls at certain processing units at several of our refineries. We are currently evaluating a selection of control technologies to assure operations flexibility and compatibility with long-term air emission reduction goals.

To meet California's CARB III gasoline requirements, including the mandatory phase out of using the oxygenate known as MTBE, we expect to spend approximately $17 million in 2003 at our California refinery. The project should be completed in the first quarter of 2003.

Estimated capital expenditures described above to comply with the Clean Air Act and California regulations are summarized in the table below (in millions).

	2003	2004	2005	2006	2007	Beyond 2007
Lower Sulphur Gasoline						
Washington	$ 3	$16	$14	$—	$—	$—
North Dakota	—	—	2	2	—	—
Utah	—	—	—	—	—	15
Total For Lower Sulphur Gasoline	3	16	16	2	—	15
Lower Sulphur Diesel						
Washington	—	1	4	5	—	—
North Dakota	—	2	3	3	—	—
Utah	4	20	—	2	1	—
California	—	3	5	2	—	—
Total For Lower Sulphur Diesel	4	26	12	12	1	—
Refinery MACT II	3	22	17	2	—	—
California CARB III Gasoline	17	—	—	—	—	—
Total	$27	$64	$45	$16	$ 1	$15

Other Environmental Matters

Extensive federal, state and local environmental laws and regulations govern our operations. These laws, which change frequently, regulate the discharge of materials into the environment and may require us to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites, install additional controls, or make other modifications or changes in use for certain emission sources.

We are currently involved in remedial responses and have incurred cleanup expenditures associated with environmental matters at a number of sites, including certain of our owned properties. At December 31, 2002, our accruals for environmental expenses totaled approximately $40 million. Our accruals for environmental expenses include retained liabilities for prior owned or operated properties, refining, pipeline, terminal and marine services operations and retail service stations. Based on currently available information, including the participation of other parties or former owners in remediation actions, we believe these accruals are adequate.

In connection with the 2001 acquisition of the North Dakota and Utah refineries, we assumed the sellers' obligations and liabilities under a consent decree among the United States, BP Exploration and Oil Co., Amoco Oil Company and Atlantic Richfield Company. BP entered into this consent decree for both the North Dakota and Utah refineries for various alleged violations. As the new owner of these refineries, we are required to address issues including leak detection and repair, flaring protection and sulfur recovery unit optimization. We currently estimate that we will spend an aggregate of $7 million to comply with this consent decree. In addition, we have agreed to indemnify the sellers for all losses of any kind incurred in connection with the consent decree.

In connection with the 2002 acquisition of the California refinery, subject to certain conditions, we assumed the seller's obligations pursuant to its settlement efforts with the Environmental Protection Agency concerning the Section 114 refinery enforcement initiative under the Clean Air Act, except for any potential monetary penalties, which the seller retains. We believe these obligations will not have a material impact on our financial position.

Based on latest estimates, we will need to expend additional capital at the California refinery for reconfiguring and replacing above ground storage tank systems and upgrading piping within the refinery. These costs are currently estimated at approximately $130 million through 2007 and an additional estimated $90 million through 2011. Both of these cost estimates are subject to further review and analysis.

In addition to these capital expenditures, the California refinery will require expenditures related to remediation. Soil and groundwater conditions at the California refinery may require substantial expenditures over time. Our current estimate of costs to address environmental liabilities including soil and groundwater conditions at the refinery in connection with various projects, including those required pursuant to orders by the California Regional Water Quality Control Board, is approximately $73 million, of which approximately $31 million is anticipated to be incurred through 2006 and the balance thereafter. We believe that we will be entitled to indemnification for approximately $63 million of such costs, directly or indirectly, from former owners or operators of the refinery (or their successors) under two separate indemnification agreements. Additionally, if remediation expenses are incurred in excess of the indemnification, we expect to receive coverage under one or both of the environmental insurance policies discussed in Note D of Notes to Consolidated Financial Statements in Item 8.

Conditions that require additional expenditures may transpire for our various sites, including, but not limited to, our refineries, tank farms, retail gasoline stations (operating and closed locations) and petroleum product terminals, and for compliance with the Clean Air Act and other state, federal and local requirements. We cannot currently determine the amount of these future expenditures.

For further information on environmental matters and other contingencies, see Note Q of Notes to Consolidated Financial Statements in Item 8.

Pension Funding

For all eligible employees, we provide a qualified defined benefit retirement plan with benefits based on years of service and compensation. Our executive security plans also provide certain executive officers and other key personnel with supplemental death or retirement benefits based on years of service and compensation. We contributed $16 million in 2002 and expect to contribute $19 million and $31 million in 2003 and 2004, respectively, to these plans. While our long-term expected return on plan assets is 8.15%, our pension plan assets experienced losses of $3 million in 2001 and $6 million in 2002. Our expected contributions in 2003 and 2004 are affected by returns on plan assets, employee demographics and other factors. See Note O of Notes to Consolidated Financial Statements in Item 8 for further discussion.

Conversion of Preferred Stock

On July 1, 2001, our Premium Income Equity Securities automatically converted into 10,350,000 shares of our common stock. This conversion eliminated $12 million in annual preferred dividend requirements. The final quarterly cash dividends were paid on July 2, 2001.

Common Stock Share Repurchase Program

During 2000, we repurchased 1,627,400 shares of common stock for approximately $15.5 million. In 2001, we repurchased an additional 304,000 shares of our common stock for $3.5 million, bringing the cumulative shares repurchased under the program to 1,931,400. In 2002, we did not repurchase any shares of our common stock. Under the revised terms of our senior secured credit facility, we are not permitted to repurchase shares of our common stock through December 31, 2003. Beginning January 1, 2004, the terms of our senior secured credit facility allow for the repurchase of shares of our common stock, not to exceed $15 million in any year.

ACCOUNTING STANDARDS

Critical Accounting Policies

Our accounting policies are described in Note B to Notes to Consolidated Financial Statements in Item 8. We prepare our Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP"), which require us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates. We consider the following policies to be most critical in understanding the judgments that are involved in preparing our financial statements and the uncertainties that could impact our results of operations, financial condition and cash flows.

Inventory — Our inventories are stated at the lower of cost or market. We use the LIFO method to determine the cost of our crude oil and refined product inventories. The carrying value of these inventories is sensitive to volatile market prices. We had 17.8 million barrels of crude oil and refined product inventories at December 31, 2002 with an average cost of $22.90 per barrel. If refined product prices decline below the average cost, then we will be required to write down the value of our inventories in future periods.

Property, Plant and Equipment — We calculate depreciation and amortization based on estimated useful lives and salvage values of our assets. When assets are placed into service, we make estimates with respect to their useful lives that we believe are reasonable. However, factors such as maintenance levels, economic conditions impacting the demand for these assets, regulation or environmental matters could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. We evaluate property, plant and equipment for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which the asset's carrying value exceeds its fair value. Estimates of future discounted cash flows and fair value of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates.

Goodwill — As of December 31, 2002, we had $91 million of goodwill. SFAS No. 142, "Goodwill and Other Intangible Assets" requires that goodwill is not to be amortized but is to be tested for impairment annually or more frequently when indicators of impairment exist. We completed the required annual test for goodwill impairment during the fourth quarter of 2002 and recognized a loss of $1.2 million to reduce the carrying value of goodwill in our Retail segment. The impairment test is highly susceptible to change from period to period as it requires management to make cash flow assumptions including, among other things, future margins, volumes, operating costs and discount rates. Management's assumptions regarding future margins and volumes require significant judgment as actual margins and volumes have fluctuated in the past and are expected to continue to do so. The impairment test performed during the fourth quarter of 2002 assumed that future margins in our geographic areas will be at five-year average levels. We are exposed to the possibility that changes in market conditions could result in additional impairment charges in the future.

Business Combinations — In 2002 and 2001, we had significant acquisitions which were accounted for as purchases, whereby the purchase prices were allocated to the assets acquired and the liabilities assumed based upon their respective fair market values at the dates of acquisition. Significant management judgment is required in determining the value of these assets and liabilities (including employee benefits, an MTBE lease obligation and environmental matters). We engaged outside specialists to assist us in determining the fair values of property, plant and equipment and intangible assets. As of December 31, 2002, we had $151 million of acquired intangible assets. The valuation of these intangible assets required us to use our judgment including estimates with respect to their useful lives. We review acquired intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The assessment of impairment is based on the estimated undiscounted future cash flows from operating activities compared with the carrying value of the assets. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which the asset's carrying value exceeds its fair value. Estimates of future discounted cash flows and fair value of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates.

Deferred Maintenance Costs — We record the cost of major scheduled refinery turnarounds, long-lived catalysts used in refinery process units and periodic maintenance on ships, tugs and barges ("drydocking") as deferred charges. We amortize these deferred charges over the expected periods of benefit, generally ranging from two to four years. The American Institute of Certified Public Accountants has issued an Exposure Draft for a Proposed Statement of Position, "Accounting for Certain Costs and Activities Related to Property, Plant and Equipment", which would require these major maintenance activities to be expensed as costs are incurred. If this proposed Statement of Position is adopted in its current form, we would be required to write off the balance of our deferred maintenance costs which totaled $62 million at December 31, 2002 and expense future costs as incurred (see "Refinery Turnaround and Other Major Maintenance" on page 46).

Contingencies — We account for contingencies in accordance with SFAS No. 5, "Accounting for Contingencies". SFAS No. 5 requires that we record an estimated loss from a loss contingency when information available prior to issuance of our financial statements indicates that it is probable that an asset has been impaired or a liability has been incurred at the date of the financial statements and the amount of the loss can be reasonably estimated. Accounting for contingencies such as environmental, legal and income tax matters requires us to use our judgment. While we believe that our accruals for these matters are adequate, if the actual loss from a loss contingency is significantly different than the estimated loss, our results of operations may be over or understated.

Income Taxes — As part of the process of preparing consolidated financial statements, we must assess the likelihood that our deferred income tax assets will be recovered through future taxable income. To the extent we believe that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining any valuation allowance recorded against net deferred income tax assets. Based on our estimates of taxable income in each jurisdiction in which we operate and the period over which deferred income tax assets will be recoverable, we have not recorded a valuation allowance as of December 31, 2002. In the event that actual results differ from these estimates or we make adjustments to these estimates in future periods, we may need to establish a valuation allowance. As of December 31, 2002, deferred tax assets included net operating loss carryforwards and alternative minimum tax credits totaling $91 million.

Pension and Other Postretirement Benefits — Accounting for pensions and other postretirement benefits involves several assumptions and estimates including discount rates, health care cost trends, inflation, retirement rates and mortality rates. We must also assume a rate of return on the plan assets in order to estimate our obligations under the plans. Due to the nature of these calculations, we engage an outside actuarial firm to assist with the determination of these estimates and the calculation of certain employee benefit expenses. While we believe that the assumptions used are appropriate, significant differences in the actual experience or significant changes in assumptions would affect pension and other postretirement benefits costs and obligations. See Note O of Notes to Consolidated Financial Statements in Item 8 for more information regarding costs and assumptions.

New Accounting Standards and Disclosures

SFAS No. 143 — On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations", which addresses financial accounting and reporting for legal obligations associated with the retirement of long-lived assets. We have identified asset retirement obligations that are within the scope of the standard, including obligations imposed by certain state laws pertaining to closure and/or removal of storage tanks, and contractual removal obligations included in certain lease and right-of-way agreements associated with our retail, pipeline and terminal operations. We have estimated the fair value of our asset retirement obligations, based in part on the terms of the agreements and the probabilities associated with the eventual sale or other disposition of these assets. We cannot currently make reasonable estimates of the fair values of some retirement obligations, principally those associated with refineries, certain pipeline rights-of-way and certain terminals, because the related assets have indeterminate useful lives which preclude development of assumptions about the potential timing of settlement dates. Such obligations will be recognized in the period in which sufficient information exists to estimate a range of potential settlement dates. The present value of obligations was accrued to the extent that settlement dates could be estimated, primarily for assets on leased sites. The effect of adopting this accounting standard at January 1, 2003, was to increase property, plant and equipment by approximately $0.6 million, net of accumulated amortization, increase noncurrent other liabilities by approximately $1.7 million, and reduce net earnings for a one-time cumulative effect charge of approximately $0.7 million, net of deferred income taxes. The annual increase in 2003 depreciation and operating expense is estimated to be less than $1 million.

SFAS No. 144 — Effective January 1, 2002, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS No. 144 retains the requirement to recognize an impairment loss only where the carrying value of a long-lived asset is not recoverable from its undiscounted cash flows and to measure such loss as the difference between the carrying amount and fair value of the assets. SFAS No. 144, among other things, changes the criteria that have to be met to classify an asset as held-for-sale and requires that operating losses from discontinued operations be recognized in the period that the losses are incurred rather than as of the measurement date. The provisions of SFAS No. 144, which were applied as related to our divestitures in 2002, did not have a significant impact on our consolidated financial condition or results of operations.

SFAS No. 145 — In April 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13 and Technical Corrections". SFAS No. 145 clarifies guidance related to the reporting of gains and losses from extinguishment of debt and resolves inconsistencies related to the required accounting treatment of certain lease modifications. SFAS No. 145 also amends other existing pronouncements to make various technical corrections, clarify meanings or describe their applicability under changed conditions. The provisions relating to the reporting of gains and losses from extinguishment of debt become effective for us beginning January 1, 2003. All other provisions of this standard became effective for us as of May 15, 2002 and did not have a significant impact on our consolidated financial condition or results of operations.

SFAS No. 146 — In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". SFAS No. 146 requires costs associated with exit or disposal activities to be recognized when they are incurred rather than at the date of a commitment to an exit or disposal plan. We early adopted SFAS No. 146 during the 2002 third quarter and the adoption did not have a material impact on our consolidated financial condition or results of operations.

SFAS No. 148 — In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an amendment of FASB Statement No. 123", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. We have not adopted the SFAS No. 123 fair value method of accounting for stock-based employee compensation (see Note P to Consolidated Financial Statements in Item 8).

EITF Issue No. 02-3 — In October 2002, the Emerging Issues Task Force ("EITF") of the FASB reached a consensus that gains and losses on derivative instruments subject to SFAS No. 133 should be shown net in the income statement whether or not settled physically if the derivative instruments are used for trading purposes. We have a limited number of petroleum purchases and sales that are within the scope of SFAS No. 133 and are used for trading purposes. Such transactions are generally settled with physical product or crude oil deliveries. We adopted the provisions of this EITF issue in the fourth quarter of 2002, and all comparative financial information has been reclassified to conform to the current presentation. There was no change in operating income (loss), net earnings (loss), cash flow or net earnings (loss) per share for any period as a result of adopting this EITF issue. However, revenues and cost of sales and operating expenses were reduced by equal and offsetting amounts. For the years ended December 31, 2002, 2001 and 2000, revenues and costs of sales and operating expenses were reduced by approximately $105 million, $38 million and $38 million, respectively, as a result of presenting these activities net in the Statements of Consolidated Operations. The margins on these transactions were not significant for these periods.

Proposed Statement of Position — In 2001, the American Institute of Certified Public Accountants ("AICPA") issued an Exposure Draft for a Proposed Statement of Position, "Accounting for Certain Costs and Activities Related to Property, Plant and Equipment". The proposed Statement of Position ("SOP"), as originally written, would require major maintenance activities, such as refinery turnarounds, to be expensed as costs are incurred. In the 2002 fourth quarter, the AICPA announced it would be transitioning this project to the FASB, although the AICPA may retain and address certain components of the proposed SOP. The FASB and the AICPA have not determined which components, if any, will be retained by the AICPA for potential issuance in a future SOP. In addition, the FASB has not set a timetable for addressing the issues raised by the proposed SOP. If this proposed SOP is adopted as originally written, we would be required to write off the unamortized carrying value of deferred major maintenance costs and expense future costs as incurred. At December 31, 2002, deferred major maintenance costs totaled $62 million.

FIN 45 — In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" ("FIN 45"). FIN 45 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and initial measurement provisions of FIN 45 are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in FIN 45 are effective for financial statements of interim and annual periods ending after December 15, 2002. The adoption of this statement did not have a significant impact on our consolidated financial statements.

FIN 46 — In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"), which requires the consolidation of variable interest entities, as defined. FIN 46 applies immediately to variable interest entities created after January 31, 2003. The consolidation requirements apply to older entities in the first fiscal year or interim period beginning after June 15, 2003. Certain of the disclosure requirements apply in all financial statements issued after January 31, 2003, regardless of when the variable interest entity was established. We believe that FIN 46 will not require consolidation of any variable interest entities.

For further information related to new accounting standards and disclosures, see Note B of Notes to Consolidated Financial Statements in Item 8.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements are included throughout this Form 10-K, including in the sections entitled "Business" and "Risk Factors", and relate to, among other things, projections of refining margins, revenues, earnings, earnings per share, cash flows, capital expenditures, working capital or other financial items, throughput, expectations regarding the acquisitions, discussions of estimated future revenue enhancements, potential dispositions and cost savings. These statements also relate to our business strategy, goals and expectations concerning our market position, future operations, margins, profitability, liquidity and capital resources. We have used the words "anticipate", "believe", "could", "estimate", "expect", "intend", "may", "plan", "predict", "project", "will" and similar terms and phrases to identify forward-looking statements in this Annual Report on Form 10-K.

Although we believe the assumptions upon which these forward-looking statements are based are reasonable, any of these assumptions could prove to be inaccurate and the forward-looking statements based on these assumptions could be incorrect. Our operations involve risks and uncertainties, many of which are outside our control, and any one of which, or a combination of which, could materially affect our results of our operations and whether the forward-looking statements ultimately prove to be correct. Accordingly, these forward-looking statements are qualified in their entirety by reference to the factors described in "Risk Factors" contained in Part I, and elsewhere, in this Annual Report on Form 10-K.

Actual results and trends in the future may differ materially from those suggested or implied by the forward-looking statements depending on a variety of factors including, but not limited to:

- changes in general economic conditions;
- the timing and extent of changes in commodity prices and underlying demand for our products;
- the availability and costs of crude oil, other refinery feedstocks and refined products;
- changes in our cash flow from operations, liquidity and capital requirements;
- our ability to achieve our debt reduction goal;
- our ability to meet debt covenants;
- adverse changes in the ratings assigned to our trade credit and debt instruments;
- reduced availability of trade credit;
- increased interest rates and the condition of the capital markets;
- the direct or indirect effects on our business resulting from actual or threatened terrorist incidents or acts of war;
- political developments in foreign countries;
- changes in our inventory levels and carrying costs;
- seasonal variations in demand for refined products;
- changes in the cost or availability of third-party vessels, pipelines and other means of transporting feedstocks and products;
- changes in fuel and utility costs for our facilities;
- disruptions due to equipment interruption or failure at our or third-party facilities;
- execution of planned capital projects;
- state and federal environmental, economic, safety and other policies and regulations, any changes therein, and any legal or regulatory delays or other factors beyond our control;
- adverse rulings, judgments, or settlements in litigation or other legal or tax matters, including unexpected environmental remediation costs in excess of any reserves;
- actions of customers and competitors;
- weather conditions affecting our operations or the areas in which our products are marketed; and
- earthquakes or other natural disasters affecting operations.

Many of these factors are described in greater detail in our filings with the SEC. All future written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the previous statements. We undertake no obligation to update any information contained herein or to publicly release the results of any revisions to any forward-looking statements that may be made to reflect events or circumstances that occur, or that we become aware of, after the date of this Annual Report on Form 10-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Changes in commodity prices and interest rates are our primary sources of market risk. We have a risk management committee responsible for overseeing energy risk management activities.

Commodity Price Risks

Our earnings and cash flows from operations depend on the margin above fixed and variable expenses (including the costs of crude oil and other feedstocks) at which we are able to sell refined products. The prices of crude oil and refined products have fluctuated substantially in recent years. These prices depend on many factors, including the demand for crude oil, gasoline and other refined products, which in turn depend on, among other factors, changes in the economy, the level of foreign and domestic production of crude oil and refined products, worldwide political conditions, the availability of imports of crude oil and refined products, the marketing of alternative and competing fuels and the extent of government regulations. The prices we receive for refined products are also affected by local factors such as local market conditions and the level of operations of other refineries in our markets.

The prices at which we sell our refined products are influenced by the commodity price of crude oil. Generally, an increase or decrease in the price of crude oil results in a corresponding increase or decrease in the price of gasoline and other refined products. The timing of the relative movement of the prices, however, can impact profit margins which could significantly affect our earnings and cash flows. In addition, the majority of our crude oil supply contracts are short-term in nature with market-responsive pricing provisions. Our financial results can be affected significantly by price level changes during the period between purchasing refinery feedstocks and selling the manufactured refined products from such feedstocks. We also purchase refined products manufactured by others for resale to our customers. Our financial results can be affected significantly by price level changes during the periods between purchasing and selling such products. Assuming all other factors remained constant, a $1.00 per barrel change in average gross refining margins based on our 2002 average throughput of 435 thousand bpd would change annual pretax segment operating income and cash flows from operations by approximately $159 million.

We maintain inventories of crude oil, intermediate products and refined products, the values of which are subject to fluctuations in market prices. In our Refining and Retail segments, our inventories of refinery feedstocks and refined products totaled 17.8 million barrels and 17.2 million barrels at December 31, 2002 and 2001, respectively. The average cost of our refinery feedstocks and refined products at December 31, 2002 was approximately $23 per barrel. If market prices for refined products decline to a level below the average cost of these inventories, we may be required to write down the carrying value of this inventory.

We periodically enter into derivative type arrangements on a limited basis, as part of our programs to acquire refinery feedstocks at reasonable costs and to manage margins on certain refined product sales. We also engage in limited non-hedging activities which are marked to market with changes in the fair value of the derivative recognized in earnings. At December 31, 2002, we had open future positions of 24,000 barrels of crude oil which expire during the first half of 2003. Recording the fair value of these positions resulted in a mark-to-market gain of less than $0.1 million in 2002. We believe that any potential impact from these activities would not result in a material adverse effect on our results of operations, financial position or cash flows.

Interest Rate Risk

At December 31, 2002, we had $918 million of outstanding floating-rate debt under the senior secured credit facility and $1.059 billion of fixed-rate debt. The weighted average interest rate on the floating-rate debt was 8.1% at December 31, 2002. The impact on annual cash flow of a 10% change in the floating-rate for our senior secured credit facility (81 basis points) would be approximately $7 million.

The fair market value of our fixed-rate debt at December 31, 2002 was approximately $326 million less than its book value of $1.059 billion, based on transactions and bid quotes for our senior subordinated notes. The fair market value of our variable-rate debt at December 31, 2002 was approximately $73 million less than its book value of $918 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholders
Tesoro Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Tesoro Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2002 and 2001, and the related statements of consolidated operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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, such consolidated financial statements present fairly, in all material respects, the financial position of Tesoro Petroleum Corporation and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

San Antonio, Texas
February 14, 2003

TESORO PETROLEUM CORPORATION

STATEMENTS OF CONSOLIDATED OPERATIONS
(In millions except per share amounts)

	Years Ended December 31,		
	2002	2001	2000
REVENUES	$7,119.3	$5,181.7	$5,066.8
COSTS AND EXPENSES:			
Costs of sales and operating expenses	6,865.7	4,797.1	4,758.9
Selling, general and administrative expenses	133.2	104.2	85.2
Depreciation and amortization	130.7	79.9	69.3
Loss on asset sales and impairment	8.4	1.8	—
OPERATING INCOME (LOSS)	(18.7)	198.7	153.4
Interest and financing costs, net of capitalized interest	(166.1)	(52.8)	(32.7)
Interest income	3.5	1.0	2.8
EARNINGS (LOSS) BEFORE INCOME TAXES	(181.3)	146.9	123.5
Income tax provision (benefit)	(64.3)	58.9	50.2
NET EARNINGS (LOSS)	(117.0)	88.0	73.3
Preferred dividend requirements	—	6.0	12.0
NET EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ (117.0)	$ 82.0	$ 61.3
NET EARNINGS (LOSS) PER SHARE			
Basic	$ (1.93)	$ 2.26	$ 1.96
Diluted	$ (1.93)	$ 2.10	$ 1.75
WEIGHTED AVERAGE COMMON SHARES			
Basic	60.5	36.2	31.2
Diluted	60.5	41.9	41.8

The accompanying notes are an integral part of these consolidated financial statements.

TESORO PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

(Dollars in millions except per share amounts)

	December 31, 2002	December 31, 2001
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 109.8	$ 51.9
Receivables, trade, less allowance for doubtful accounts	412.2	362.4
Income taxes receivable	41.9	22.5
Inventories	461.5	431.8
Prepayments and other	28.8	9.4
Total Current Assets	1,054.2	878.0
PROPERTY, PLANT AND EQUIPMENT		
Refining	2,363.1	1,522.0
Retail	239.0	228.8
Corporate and Other	111.0	101.9
	2,713.1	1,852.7
Less accumulated depreciation and amortization	(409.7)	(330.4)
Net Property, Plant and Equipment	2,303.4	1,522.3
OTHER NONCURRENT ASSETS		
Goodwill	91.1	95.2
Acquired intangibles, net	150.6	73.3
Other, net	159.5	93.5
Total Other Noncurrent Assets	401.2	262.0
Total Assets	$3,758.8	$2,662.3
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 338.6	$ 331.2
Accrued liabilities	199.7	172.9
Current maturities of debt	70.0	34.4
Total Current Liabilities	608.3	538.5
DEFERRED INCOME TAXES	128.7	136.9
OTHER LIABILITIES	227.5	117.4
DEBT	1,906.7	1,112.5
COMMITMENTS AND CONTINGENCIES (Note Q)		
STOCKHOLDERS' EQUITY		
Common stock, par value $0.16⅔; authorized 100,000,000 shares; 66,379,928 shares issued (43,371,825 in 2001)	11.0	7.2
Additional paid-in capital	689.8	448.4
Retained earnings	204.9	321.9
Treasury stock, 1,771,695 common shares (1,958,147 in 2001), at cost	(18.1)	(20.5)
Total Stockholders' Equity	887.6	757.0
Total Liabilities and Stockholders' Equity	$3,758.8	$2,662.3

The accompanying notes are an integral part of these consolidated financial statements.

TESORO PETROLEUM CORPORATION

STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY
(In millions)

	Preferred Stock		Common Stock		Additional Paid-In Capital	Retained Earnings	Treasury Stock	
	Shares	Amount	Shares	Amount			Shares	Amount
AT JANUARY 1, 2000	0.1	$ 165.0	32.7	$ 5.4	$279.0	$178.6	(0.3)	$ (4.9)
Net earnings	—	—	—	—	—	73.3	—	—
Preferred dividend requirements	—	—	—	—	—	(12.0)	—	—
Shares repurchased and shares issued for stock options	—	—	0.1	—	1.0	—	(1.6)	(15.5)
AT DECEMBER 31, 2000	0.1	165.0	32.8	5.4	280.0	239.9	(1.9)	(20.4)
Net earnings	—	—	—	—	—	88.0	—	—
Preferred dividend requirements	—	—	—	—	—	(6.0)	—	—
Preferred stock conversion	(0.1)	(165.0)	10.3	1.7	163.3	—	—	—
Shares repurchased and shares issued for stock options and benefit plans	—	—	0.3	0.1	5.1	—	(0.1)	(0.1)
AT DECEMBER 31, 2001	—	—	43.4	7.2	448.4	321.9	(2.0)	(20.5)
Net loss	—	—	—	—	—	(117.0)	—	—
Issuance of common stock	—	—	23.0	3.8	241.3	—	—	—
Shares issued for stock options and benefit plans	—	—	—	—	0.1	—	0.2	2.4
AT DECEMBER 31, 2002	—	$ —	66.4	$11.0	$689.8	$204.9	(1.8)	$(18.1)

The accompanying notes are an integral part of these consolidated financial statements.

TESORO PETROLEUM CORPORATION

STATEMENTS OF CONSOLIDATED CASH FLOWS
(In millions)

	Years Ended December 31,		
	2002	2001	2000
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES			
Net earnings (loss)	$(117.0)	$ 88.0	$ 73.3
Adjustments to reconcile net earnings (loss) to net cash from operating activities:			
Depreciation and amortization	130.7	79.9	69.3
Loss on asset sales and impairment	8.4	1.8	—
Deferred income taxes	3.3	35.5	21.4
Changes in deferred assets and other liabilities	(11.2)	4.5	(4.6)
Changes in current assets and current liabilities:			
Receivables, trade	(49.8)	(32.6)	(62.7)
Income taxes receivable	(19.4)	(22.2)	4.7
Inventories	115.9	(29.1)	(92.1)
Prepayments and other	(20.7)	1.2	(1.0)
Accounts payable and accrued liabilities	17.6	87.4	82.1
Net cash from operating activities	57.8	214.4	90.4
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES			
Capital expenditures	(203.5)	(209.5)	(94.0)
Acquisitions	(931.5)	(783.4)	—
Proceeds from asset sales	207.4	20.7	2.4
Other	(13.1)	(4.5)	3.6
Net cash used in investing activities	(940.7)	(976.7)	(88.0)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES			
Proceeds from debt offerings, net of issuance costs of $9.4 and $5.1	440.6	209.9	—
Proceeds from Common Stock offering, net of issuance costs of $13.7	245.1	—	—
Borrowings under term loans	425.0	625.0	—
Repayments of debt	(133.0)	(1.1)	(105.9)
Payment of dividends on Preferred Stock	—	(9.0)	(9.0)
Repurchases of Common Stock	—	(3.5)	(15.5)
Financing costs and other	(36.9)	(21.2)	0.3
Net cash from (used in) financing activities	940.8	800.1	(130.1)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	57.9	37.8	(127.7)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	51.9	14.1	141.8
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 109.8	$ 51.9	$ 14.1
SUPPLEMENTAL CASH FLOW DISCLOSURES			
Interest paid, net of capitalized interest	$ 114.3	$ 40.2	$ 17.9
Income taxes paid (refunded)	$ (48.0)	$ 47.0	$ 22.6

The accompanying notes are an integral part of these consolidated financial statements.

TESORO PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE A — NATURE OF OPERATIONS AND BUSINESS CONDITIONS

Tesoro Petroleum Corporation ("Tesoro" or the "Company") was incorporated in Delaware in 1968 and is an independent refiner and marketer of petroleum products. Tesoro owns and operates six petroleum refineries in the western and mid-continental United States with a combined rated crude oil throughput capacity of 558,000 barrels per day ("bpd") and sells refined products to a wide variety of customers primarily in the western and mid-continental United States. Tesoro markets products to wholesale and retail customers, as well as commercial end-users. Tesoro's retail business includes a network of 593 branded retail stations operated by the Company or independent dealers.

The Company's earnings, cash flows from operations and liquidity depend upon many factors, including producing and selling refined products at margins above fixed and variable expenses. The prices of crude oil and refined products have fluctuated substantially in the Company's markets. The Company's operating results can be significantly influenced by the timing of changes in crude oil costs and how quickly refined product prices adjust to reflect these changes. These price fluctuations depend on numerous factors beyond the Company's control, including the demand for crude oil, gasoline and other refined products, which is subject to, among other things, changes in the economy and the level of foreign and domestic production of crude oil and refined products, worldwide political conditions, threatened or actual terrorist incidents or acts of war, availability of crude oil and refined product imports, the infrastructure to transport crude oil and refined products, weather conditions, earthquakes and other natural disasters, seasonal variation, government regulations and local factors, including market conditions and the level of operations of other refineries in the Company's markets. As a result of these factors, margin fluctuations during any reporting period can have a significant impact on the Company's results of operations, cash flows, liquidity and financial position.

During 2002, the refining industry in the Company's market areas experienced the lowest refined product margins since 1998 and margins that were significantly below the Company's five-year average (from January 1, 1998 through December 31, 2002). The Company determines the "five-year average" by comparing gasoline, diesel and jet fuel prices to crude oil prices in the Company's market areas, with volumes weighted according to the Company's typical refinery yields. The Company experienced net losses in each of the 2002 quarters resulting from weak industry margins and additional interest and financing costs related to the Company's acquisitions of the California refinery in May 2002 and the Mid-Continent refineries in September 2001. In connection with these acquisitions, the Company's total debt increased by approximately $1.7 billion from June 30, 2001 to June 30, 2002. In addition, the ratings of the Company's senior secured credit facility and senior subordinated notes were downgraded. The Company has also experienced a tightening of the trade credit it receives, which has required it to issue an increased amount of letters of credit and make early payments and prepayments to certain suppliers.

Despite the weak margin environment, the Company generated cash flows from operations of $58 million in 2002 and reduced term debt by $140 million (including a $16.3 million prepayment in January 2003) following the acquisition of the California refinery by selling over $200 million in assets, eliminating or deferring capital expenditures, reducing expenses, achieving operating synergies and reducing inventories. As of December 31, 2002, the Company had $110 million in cash, no borrowings under the revolving credit facility and, with $60 million in letters of credit outstanding, had total unused credit available of $165 million and a total debt to capitalization ratio of 69%.

Management believes the industry conditions that led to low margins in 2002 have improved, and if this improvement continues and margins remain at or near the five-year average for the remainder of 2003, management believes the Company will comply with the financial covenants of the Company's senior secured credit facility in 2003. Industry margins in 2003 in most of the Company's market areas have averaged above the Company's five-year average (as described above).

However, if industry margins in the Company's market areas drop below the five-year average for any substantial period of time or if the Company finds it necessary to borrow the remaining available amounts under its senior secured credit facility for working capital purposes, including to support trade credit requirements, the Company will likely need to amend its senior secured credit facility because it may not meet certain financial covenant tests during the remainder of 2003. In addition, the Company's credit ratings may be further reduced and its trade credit may be further tightened. Management believes that the Company will be able to amend its senior secured credit facility or obtain covenant waivers if necessary; however, management cannot provide any assurances that the Company will be able to obtain such an amendment or waiver on terms and conditions acceptable to the Company or at all.

To better enable the Company to withstand a low margin environment similar to that experienced in 2002, management's 2003 goals are to further reduce ongoing cash expenses and eliminate or defer capital expenditures. Assuming these initiatives are realized and, if necessary, the Company is able to amend its senior secured credit facility or obtain covenant waivers, management believes cash flow from operations, amounts available under the Company's senior secured credit facility and available cash will be adequate to meet the Company's anticipated requirements in 2003 for working capital, capital expenditures and scheduled payments of principal and interest on its indebtedness.

In addition, management is pursuing discussions regarding possible financing alternatives to replace the Company's senior secured credit facility. If the Company pursues such alternatives, management intends to seek a debt structure designed (1) to increase the Company's capacity to borrow for working capital needs, (2) to allow the Company to issue letters of credit instead of making early payments and prepayments to certain suppliers and apply the funds that would otherwise have been used for those payments and prepayments to repay debt and (3) to substantially modify the financial covenants the Company has under its existing senior secured credit facility. However, the Company cannot provide any assurances that such financing alternatives will be available on terms and conditions acceptable to management or at all.

See Notes M and O for information regarding deferred financing costs related to the senior secured credit facility and charges for enhanced retirement plan benefits.

NOTE B — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The accompanying Consolidated Financial Statements include the accounts of Tesoro and its subsidiaries. All significant intercompany accounts and transactions have been eliminated.

Investments in entities in which Tesoro has the ability to exercise significant influence, but not control, are accounted for by the equity method, while all other investments are carried at cost. These investments are not material, either individually or in the aggregate, to Tesoro's financial position, results of operations or cash flows. See Note Q for information related to a 50% limited partnership interest which is accounted for under the equity method.

Basis of Presentation

Certain previously reported amounts have been reclassified to conform to the 2002 presentation. The Company has reclassified the amortization of major maintenance refinery turnaround, catalyst and drydocking costs from costs of sales and operating expenses to depreciation and amortization in the Statements of Consolidated Operations (see "Other Assets" below for the amounts that were reclassified). The Company also has reclassified revenues and costs of sales in the Statements of Consolidated Operations to report certain crude oil and product purchases and resales on a net basis (see "New Accounting Standards and Disclosures — EITF Issue No. 02-3" below for the amounts that were reclassified).

Separate financial statements of Tesoro's subsidiary guarantors are not included herein because these subsidiary guarantors are jointly and severally liable on the Company's outstanding senior subordinated notes and the net assets, results of operations and equity of the subsidiary guarantors are substantially equivalent to the net assets, results of operations and equity of Tesoro on a consolidated basis.

Use of Estimates

Preparation of the Company's Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates.

Cash and Cash Equivalents

The Company considers all highly-liquid instruments, such as temporary cash investments, with a maturity of three months or less at the time of purchase to be cash equivalents. Cash equivalents are stated at cost, which approximates market value. The Company's policy is to invest cash in conservative, highly-rated instruments and to invest in various financial institutions to limit the amount of credit exposure in any one institution. The Company monitors the credit standing of these financial institutions. At December 31, 2002, cash and cash equivalents included $16.3 million which was used to prepay term loans in January 2003 as required by the Company's senior secured credit facility (see Note G).

Financial Instruments

The carrying amounts of financial instruments, including cash and cash equivalents, receivables, accounts payable and certain accrued liabilities, approximate fair value because of the short maturity of these instruments. The carrying amounts of the Company's debt and other obligations may vary from the Company's estimates of the fair value of such items. At December 31, 2002, the fair market value of the Company's fixed-rate debt was estimated by management to be approximately $326 million less than its book value of $1.059 billion. At December 31, 2002, the fair market value of the Company's variable-rate debt was estimated by management to be approximately $73 million less than its book value of $918 million.

Inventories

Inventories are stated at the lower of cost or market. The last-in, first-out ("LIFO") is the primary method used to determine the cost of inventories of crude oil and refined products in the Refining and Retail segments. The cost of certain inventories of fuel, oxygenates and by-products are determined using the first-in, first-out ("FIFO") method. The carrying value of petroleum inventories is sensitive to volatile market prices. Merchandise and materials and supplies are valued at average cost, not in excess of market value.

Property, Plant and Equipment

Additions to property, plant and equipment and major improvements and modifications are capitalized at cost. Depreciation of property, plant and equipment is generally computed on the straight-line method based upon the estimated useful life of each asset. The weighted average lives range from 27 to 28 years for refineries, 5 to 16 years for terminals, 13 to 16 years for retail stations, 9 to 29 years for transportation assets, and 3 to 14 years for corporate assets.

The Company capitalizes interest on major projects during extended construction periods. Such interest is allocated to property, plant and equipment and amortized over the estimated useful lives of the related assets. Interest and financing costs incurred totaled $168.6 million, $57.9 million and $33.4 million in 2002, 2001 and 2000, respectively, of which $2.5 million, $5.1 million and $0.7 million was capitalized during 2002, 2001 and 2000, respectively.

Environmental Expenditures

Environmental expenditures that extend the life or increase the capacity of facilities, or expenditures that mitigate or prevent environmental contamination that is yet to occur, are capitalized. Expenditures that relate to an existing condition caused by past operations, and which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or remedial efforts are probable. Cost estimates are based on the expected timing and extent of remedial actions required by applicable governing agencies, experience gained from similar sites on which environmental assessments or remediation have been completed, and the amount of the Company's anticipated liability considering the proportional liability and financial abilities of other responsible parties. Generally, the timing of these accruals coincides with the completion of a feasibility study or the Company's commitment to a formal plan of action. Estimated liabilities are not discounted to present value.

Goodwill and Acquired Intangibles

Goodwill represents the excess of cost (purchase price) over the fair value of net assets acquired. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 142, "Goodwill and Other Intangible Assets", the Company ceased amortizing goodwill on January 1, 2002. Goodwill amortization amounted to $2.7 million in each of 2001 and 2000 and is included in depreciation and amortization in the Statements of Consolidated Operations. The following table reflects reported net earnings and earnings per share in 2001 and 2000, adjusted to exclude goodwill amortization (in millions except per share amounts):

	2001	2000
Reported net earnings	$88.0	$73.3
Goodwill amortization, net of income taxes	2.4	2.4
Adjusted net earnings	$90.4	$75.7
Basic earnings per share:		
Reported basic earnings per share	$2.26	$1.96
Goodwill amortization, net of income taxes	0.07	0.08
Adjusted basic earnings per share	$2.33	$2.04
Diluted earnings per share:		
Reported diluted earnings per share	$2.10	$1.75
Goodwill amortization, net of income taxes	0.06	0.06
Adjusted diluted earnings per share	$2.16	$1.81

Acquired intangibles consist primarily of air emissions credits, permits and plans, and customer agreements and contracts which are recorded at fair value as of the date acquired in a business combination. Amortization is computed on a straight-line basis over estimated useful lives of 3 to 28 years.

Amortization of acquired intangibles is included in depreciation and amortization in the Statements of Consolidated Operations.

Other Assets

Refinery processing units are shut down periodically for major scheduled maintenance, or turnarounds. Certain catalysts are used in refinery process units for periods exceeding one year. Also, ships, tugs and barges are drydocked for periodic maintenance. Turnaround, catalyst and drydocking costs are deferred and amortized on a straight-line basis over the expected periods of benefit generally ranging from 23 to 48 months. Amortization of such deferred costs is included in depreciation and amortization in the Statements of Consolidated Operations and amounted to $27.2 million, $22.5 million and $23.8 million in 2002, 2001 and 2000, respectively.

Debt issuance costs related to the Company's senior secured credit facility and its subordinated notes are deferred and amortized over the estimated terms of each instrument. The amortization is included in interest and financing costs in the Statements of Consolidated Operations. The Company evaluates the carrying value of debt issuance costs when modifications are made to the related debt instruments (see Note M).

Impairment of Long-Lived Assets

Property, plant and equipment and other long-lived assets including acquired intangible assets are reviewed for impairment whenever events or changes in business circumstances indicate the carrying values of the assets may not be recoverable. Impairment losses would be recorded when the undiscounted cash flows estimated to be generated by those assets are less than the carrying amount of those assets. Factors that would indicate potential impairment include, but are not limited to, significant decreases in the market value of a long-lived asset, a significant change in the long-lived asset's physical condition and operating or cash flow losses associated with the use of the long-lived asset. Goodwill balances are reviewed for impairment annually or more frequently whenever events or changes in business circumstances indicate the carrying values of the assets may not be recoverable.

Revenue Recognition

The Company recognizes revenues from product sales upon delivery to customers and when all significant obligations have been satisfied. Certain crude oil and product purchases and resales used for trading purposes are included in revenues on a net basis. Transportation fees charged to customers are included in revenues and the related costs are included in costs of sales in the Statements of Consolidated Operations. In the Company's Retail segment, Federal excise and state motor fuel taxes collected from customers and remitted to governmental agencies are reported in revenues and in costs of sales. These taxes, primarily related to sales of gasoline and diesel fuel, totaled $167 million, $81 million and $43 million in 2002, 2001 and 2000, respectively. In the Company's Refining segment, excise taxes on sales are not included in revenues and costs of sales.

Income Taxes

Deferred tax assets and liabilities are recognized for future income tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases. Measurement of deferred tax assets and liabilities is based on enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period that includes the enactment date. A valuation allowance is provided for deferred tax assets if it is more likely than not those items will either expire before the Company is able to realize their benefit, or that future deductibility is uncertain.

Stock-Based Compensation

The Company accounts for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the quoted market price of the Company's Common Stock at the date of grant over the amount an employee must pay to acquire the stock. The following table represents the effect on net earnings and earnings per share if the Company had applied a fair value based method and recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation", for the grant of stock options (in millions except per share amounts):

	2002	2001	2000
Reported net earnings (loss)	$(117.0)	$88.0	$73.3
Deduct total stock-based employee compensation expense determined under fair value based methods for all awards, net of related tax effects	(3.8)	(2.7)	(4.4)
Pro forma net earnings (loss)	$(120.8)	$85.3	$68.9
Net earnings (loss) per share:			
Basic, as reported	$ (1.93)	$2.26	$1.96
Basic, pro forma	$ (2.00)	$2.19	$1.82
Diluted, as reported	$ (1.93)	$2.10	$1.75
Diluted, pro forma	$ (2.00)	$2.04	$1.65

For purposes of the pro forma disclosures above, the estimated fair value of stock-based compensation plans is amortized to expense primarily over the vesting period. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions for 2002, 2001 and 2000, respectively: expected volatility of 88%, 43% and 57%; risk free interest rates of 4.2%, 4.9% and 5.8%; expected lives of seven years; and no dividend yields. The estimated average fair value per share of options granted during 2002, 2001 and 2000 were $4.27, $6.72 and $6.21, respectively. See Note P for further information on the Company's stock-based employee compensation.

Derivative Instruments

The Company accounts for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS No. 138 and interpreted by the Derivatives Implementation Group. The Company believes that substantially all of its supply and marketing agreements and other commercial contracts are normal purchases and sales and that pricing provisions in these agreements are not embedded derivatives. However, the Company periodically enters into derivatives arrangements, on a limited basis, as part of its programs to acquire refinery feedstocks at reasonable costs and to manage margins on certain refined product sales. These non-hedging derivatives are marked to market with changes in the fair value of the derivatives recognized in earnings in the Statements of Consolidated Operations and the carrying amounts included in other current assets or accrued liabilities in the Consolidated Balance Sheets. At December 31, 2002, the Company had open future positions for 24,000 barrels of crude oil which expire during the first half of 2003. The fair value of these positions resulted in a mark-to-market gain of $81,000 in 2002. During 2002 and 2001, the Company did not have any derivative instruments that were designated and accounted for as hedges.

New Accounting Standards and Disclosures

SFAS No. 143

On January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations", which addresses financial accounting and reporting for legal obligations associated with the retirement of long-lived assets. The Company has identified asset retirement obligations that are within the scope of the standard, including obligations imposed by certain state laws pertaining to closure and/or removal of storage tanks, and contractual removal obligations included in certain lease and right-of-way agreements associated with the Company's retail, pipeline and terminal operations. The Company has estimated the fair value of its asset retirement obligations, based in part on the terms of the agreements and the probabilities associated with the eventual sale or other disposition of these assets. The Company cannot currently make reasonable estimates of the fair values of some retirement obligations, principally those associated with refineries, certain pipeline rights-of-way and certain terminals, because the related assets have indeterminate useful lives which preclude development of assumptions about the potential timing of settlement dates. Such obligations will be recognized in the period in which sufficient information exists to estimate a range of potential settlement dates. The present value of obligations was accrued to the extent that settlement dates could be estimated, primarily for assets on leased sites. The effect of adopting this accounting standard at January 1, 2003, was to increase property, plant and equipment by approximately $0.6 million, net of accumulated amortization, increase noncurrent other liabilities by approximately $1.7 million, and reduce net earnings for a one-time cumulative effect charge of approximately $0.7 million, net of deferred income taxes. The estimated annual increase in 2003 depreciation and operating expense is estimated to be less than $1 million.

SFAS No. 144

Effective January 1, 2002, the Company adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS No. 144 retains the requirement to recognize an impairment loss only where the carrying value of a long-lived asset is not recoverable from its undiscounted cash flows and to measure such loss as the difference between the carrying amount and fair value of the asset. SFAS No. 144, among other things, changes the criteria that have to be met to classify an asset as held-for-sale and requires that operating losses from discontinued operations be recognized in the period that the losses are incurred rather than as of the measurement date. The provisions of SFAS No. 144, which were applied to the Company's divestitures in 2002, did not have a significant impact on the Company's consolidated financial condition or results of operations (see Note E).

SFAS No. 145

In April 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13 and Technical Corrections". SFAS No. 145 clarifies guidance related to the reporting of gains and losses from extinguishment of debt and resolves inconsistencies related to the required accounting treatment of certain lease modifications. SFAS No. 145 also amends other existing pronouncements to make various technical corrections, clarify meanings or describe their applicability under changed conditions. The provisions relating to the reporting of gains and losses from extinguishment of debt become effective for the Company beginning January 1, 2003. All other provisions of this standard became effective for the Company as of May 15, 2002 and did not have a significant impact on the Company's consolidated financial condition or results of operations.

SFAS No. 146

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". SFAS No. 146 requires costs associated with exit or disposal activities to be recognized when they are incurred rather than at the date of a commitment to an exit or disposal plan. The Company early adopted SFAS No. 146 during the 2002 third quarter, which did not have a material impact on the Company's consolidated financial condition or results of operations.

SFAS No. 148

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an amendment of FASB Statement No. 123", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The Company has not adopted the fair value method of accounting for stock-based employee compensation under SFAS No. 123. See "Stock-Based Compensation" discussed above and Note P.

EITF Issue No. 02-3

In October 2002, the Emerging Issues Task Force ("EITF") of the FASB reached a consensus that gains and losses on derivative instruments subject to SFAS No. 133 should be shown net in the income statement whether or not settled physically if the derivative instruments are used for trading purposes. The Company has a limited number of petroleum purchases and sales that are within the scope of SFAS No. 133 and are used for trading purposes. Such transactions are generally settled with physical product or crude oil deliveries. The Company adopted the provisions of this EITF issue in the fourth quarter of 2002, and all comparative financial information has been reclassified to conform to the current presentation. There was no change in the Company's results of operations, cash flows or financial position for any period as a result of adopting this EITF issue. However, revenues and cost of sales and operating expenses were reduced by equal and offsetting amounts. For the years ended December 31, 2002, 2001 and 2000, revenues and costs of sales and operating expenses were reduced by approximately $105.5 million, $37.9 million and $37.6 million, respectively, as a result of presenting these activities net in the Statements of Consolidated Operations. The margins on these transactions were not significant for these periods.

Proposed Statement of Position

In 2001, the American Institute of Certified Public Accountants ("AICPA") issued an Exposure Draft for a Proposed Statement of Position, "Accounting for Certain Costs and Activities Related to Property, Plant and Equipment". The proposed Statement of Position ("SOP"), as originally written, would require major maintenance activities, such as refinery turnarounds, to be expensed as costs are incurred. In the 2002 fourth quarter, the AICPA announced it would be transitioning this project to the FASB, although the AICPA may retain and address certain components of the proposed SOP. The FASB and the AICPA have not determined which components, if any, will be retained by the AICPA for potential issuance in a future SOP. In addition, the FASB has not set a timetable for addressing the issues raised by the proposed SOP. If this proposed SOP is adopted as originally written, the Company would be required to write off the unamortized carrying value of deferred major maintenance costs and to expense future costs as incurred. At December 31, 2002, deferred major maintenance costs, which are included in noncurrent other assets — other in the Consolidated Balance Sheets, totaled $62.1 million.

FIN 45

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" ("FIN 45"). FIN 45 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and initial measurement provisions of FIN 45 are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in

FIN 45 are effective for financial statements of interim and annual periods ending after December 15, 2002. The adoption of FIN 45 did not have a significant impact on the Company's consolidated financial statements.

FIN 46

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"), which requires the consolidation of variable interest entities, as defined. FIN 46 applies immediately to variable interest entities created after January 31, 2003. The consolidation requirements apply to older entities in the first fiscal year or interim period beginning after June 15, 2003. Certain of the disclosure requirements apply to all financial statements issued after January 31, 2003, regardless of when the variable interest entity was established. The Company believes that FIN 46 will not result in the consolidation of any variable interest entities.

NOTE C — EARNINGS (LOSS) PER SHARE

Basic earnings (loss) per share are determined by dividing net earnings (loss) applicable to Common Stock by the weighted average number of common shares outstanding during the period. The calculation of diluted earnings per share takes into account the effects of potentially dilutive shares outstanding during the period. The assumed conversion of common stock equivalents produced anti-dilutive results for 2002 and was not included in the calculation of diluted earnings per share. For 2001 and 2000, the effects of potentially dilutive shares, principally the maximum shares which would have been issued assuming conversion of Preferred Stock at the beginning of the period and stock options, were considered in the dilutive calculation. The Preferred Stock was converted into 10.35 million shares of Common Stock in July 2001. Earnings (loss) per share calculations are presented below (in millions except per share amounts):

	2002	2001	2000
Basic:			
Numerator:			
Net earnings (loss)	$(117.0)	$88.0	$73.3
Less dividends on Preferred Stock	—	6.0	12.0
Net earnings (loss) applicable to Common Stock	$(117.0)	$82.0	$61.3
Denominator:			
Weighted average common shares outstanding	60.5	36.2	31.2
Basic earnings (loss) per share	$ (1.93)	$2.26	$1.96

	2002	2001	2000
Diluted:			
Numerator:			
Net earnings (loss) applicable to Common Stock	$(117.0)	$82.0	$61.3
Plus income impact of assumed conversion of Preferred Stock	—	6.0	12.0
Total	$(117.0)	$88.0	$73.3
Denominator:			
Weighted average common shares outstanding	60.5	36.2	31.2
Add potentially dilutive securities:			
Incremental dilutive shares from assumed exercise of stock options and other (anti-dilutive in 2002)	—	0.5	0.3
Incremental dilutive shares from assumed conversion of Preferred Stock	—	5.2	10.3
Total diluted shares	60.5	41.9	41.8
Diluted earnings (loss) per share	$ (1.93)	$2.10	$1.75

NOTE D — ACQUISITIONS

California Assets Acquisition

On May 17, 2002, the Company acquired a 168,000 bpd refinery located in Martinez, California in the San Francisco Bay area along with 70 associated retail sites throughout northern California (collectively, the "California Assets"). The cash purchase price for the California Assets, after post-closing adjustments, was approximately $923 million, including approximately $130 million for feedstock, refined product and other inventories. In addition, the Company issued to the seller two ten-year junior subordinated notes with face amounts aggregating $150 million, with a present value at the acquisition date of approximately $61 million (see Note G). The purchase price was determined as part of a competitive bid process. The Company incurred direct costs related to this transaction of approximately $9 million. The California refinery increased the size and scope of the Company's operations in California, and enables the Company to increase its yield of higher-value products, increase processing of heavier lower-cost crude oil, and diversify earnings and geographic exposure.

In connection with the acquisition of the California Assets, the Company assumed certain related liabilities and obligations (including costs associated with employee benefits, a lease obligation and environmental matters), subject to specific levels of indemnification. As part of the preliminary purchase price allocation, which remains subject to change, the Company has recorded approximately $112 million related to these liabilities. These liabilities include, subject to certain exceptions, certain of the seller's obligations, liabilities, costs and expenses for environmental compliance matters relating to the assets, including certain known and unknown obligations, liabilities, costs and expenses arising or incurred prior to, on or after the closing date. See Note Q for further information on environmental matters related to the California Assets.

The Company also assumed and took assignment of certain of the seller's obligations and rights (including certain indemnity rights) arising out of or related to the agreement pursuant to which the seller purchased the refinery in 2000. In addition, upon the acquisition of the California Assets, the Company took assignment from the seller of two environmental insurance policies. The policies provide $140 million of coverage in excess of a $50 million indemnity covering certain environmental liabilities.

The purchase price was allocated to the assets acquired and liabilities assumed based upon their respective estimated fair market values at the date of acquisition. The accompanying financial statements reflect the preliminary purchase price allocation, which is subject to change pending completion of independent appraisals and other evaluations. The accompanying financial statements include the results of operations of the California Assets since the date of acquisition. The preliminary purchase price allocation, including direct costs incurred in the California Assets acquisition, is as follows (in millions):

Inventories	$150
Property, plant and equipment	848
Acquired intangibles	88
Other assets	19
Accrued liabilities	(20)
Other liabilities	(92)
Total purchase price	$993

Property, plant and equipment includes amounts allocated to the 70 northern California retail sites that approximated the cash proceeds the Company received upon selling these sites in December 2002 (see Note E). The acquired intangibles of $88 million consist primarily of air emissions credits and have a weighted-average useful life of approximately 27 years. Other liabilities include obligations for employee benefits, environmental costs and a lease termination obligation. The lease termination obligation of $32 million reflects the operating lease payments from 2004 to 2010 on an MTBE facility located at the refinery. Current governmental regulations require that the use of MTBE be phased out by the end of 2003. The Company expects to complete a project in the first quarter of 2003 which will allow the Company to phase out MTBE by December 31, 2003 and cease operating the leased facility. The lease termination obligation is classified as noncurrent because the Company anticipates that it will continue making the lease payments through the life of the lease.

The following unaudited pro forma financial information for the years ended December 31, 2002 and 2001 gives effect to the acquisition of the California Assets and related financings, including (i) the March 2002 public offering of 23 million shares of common stock, (ii) additional borrowings under the senior secured credit facility and (iii) the issuance of the 9⅝% senior subordinated notes due 2012 (see Notes G and H below), as if each had occurred at the beginning of the periods presented. This pro forma information is based on historical data (in millions except per share amounts) and the Company believes it is not indicative of the results of future operations.

	2002	2001
Revenues	$7,793	$7,104
Net earnings (loss)	$ (163)	$ 121
Net earnings (loss) per share:		
Basic	$(2.53)	$ 1.93
Diluted	$(2.53)	$ 1.86

Mid-Continent Acquisition

On September 6, 2001, the Company acquired two refineries in North Dakota and Utah and related storage, distribution and retail assets. The acquired assets included a 60,000 bpd refinery in Mandan, North Dakota and a 55,000 bpd refinery in Salt Lake City, Utah. The Company also acquired a product pipeline extending from Mandan, North Dakota to Minneapolis, Minnesota and terminals in Jamestown, North Dakota and Moorhead, Sauk Centre and Minneapolis/St. Paul, Minnesota ("Product Pipeline System"). The acquired assets also included related bulk storage facilities and retail assets consisting of 42 retail stations and contracts to supply a jobber network of over 280 retail stations. In connection with the acquisition of the North Dakota refinery, the Company purchased the North Dakota-based, common-carrier crude oil pipeline and gathering system ("Crude Oil Pipeline System") on November 1, 2001. The Crude Oil Pipeline System is the primary crude supply carrier for the Company's North Dakota refinery. The purchase of the Crude Oil Pipeline System, Product Pipeline System and the acquisition of the North Dakota and Utah refineries and related storage, distribution and retail assets are collectively referred to as the "Mid-Continent Acquisition". The Mid-Continent Acquisition enables the Company to increase the size and scope of its operations and to diversify its earnings and geographic exposure. The Company paid $756 million in cash (including $83 million for hydrocarbon inventories) for these assets. The purchase price was determined through a competitive bid process. In addition, the Company incurred direct costs related to this transaction of $8 million.

In connection with the Mid-Continent Acquisition, Tesoro assumed certain liabilities and obligations (including costs associated with transferred employees and environmental matters) related to the acquired assets, subject to specified levels of indemnification. These include, subject to certain exceptions, certain of the sellers' obligations, liabilities, costs and expenses for violations of health, safety and environmental laws relating to the assets, including certain known and unknown obligations, liabilities, costs and expenses arising or incurred prior to, on or after the closing dates. In addition, the Company has agreed to indemnify the sellers for all losses of any kind incurred in connection with or related to these assumed liabilities. See Note Q for environmental matters related to the Mid-Continent Acquisition.

The purchase price was allocated to the assets acquired and liabilities assumed based upon their respective fair market values at the date of acquisition. The financial statements include the results of operations of the Mid-Continent Acquisition since the dates of acquisition. During 2002, independent appraisals and other evaluations were completed and the Company finalized the purchase price allocation resulting in a decrease of $2.9 million in goodwill, an increase of $1.9 million in employee benefit obligations and an increase of $4.9 million in deferred tax assets. No other significant adjustments to the preliminary 2001 allocations were necessary.

In December 2002, the Company sold the Product Pipeline System for $100 million in cash (see Note E).

Retail

In November 2001, the Company acquired 46 retail fueling facilities, including 37 retail stations with convenience stores and nine commercial card lock facilities, located in Washington, Oregon and Idaho.

NOTE E — DIVESTITURES

In June 2002, the Company announced a goal to reduce debt by the end of 2003. As part of this debt reduction, the Company set a goal to generate net proceeds of $200 million through asset sales. Furthermore, the Company's senior secured credit facility, as amended in September and December 2002, required the Company to consummate one or more asset sales or equity offerings resulting in the receipt of cumulative net proceeds of at least $200 million by March 31, 2003.

On December 26, 2002, the Company sold its product pipeline extending from Mandan, North Dakota to Minneapolis, Minnesota and terminals in Jamestown, North Dakota and Moorhead, Sauk Centre and Minneapolis/St. Paul, Minnesota for $100 million in cash. The Company's gain on the sale of these assets was immaterial. The Company will continue to distribute products from its North Dakota refinery through the product pipeline under a tariff arrangement with the new owner.

In December 2002, the Company sold 70 retail stations in northern California for $66 million in cash, including inventories. The Company acquired these stations in May 2002 as part of the California Assets acquisition. The Company recognized a loss on the sale of $2.5 million. The Company will continue to sell products to a majority of the stations under a two-year unbranded supply agreement. The Company retained responsibility for all environmental liabilities at the stations arising prior to the date of sale.

On December 31, 2002, the Company completed a sale/lease-back transaction for 30 of its retail stations located in Alaska, Hawaii, Idaho and Utah for cash proceeds of $40 million. The Company recognized a loss on the sale of $4 million. The leases are for land, buildings and certain equipment and have an initial term of 17 years with four 5-year renewal options. The portion of the lease attributable to land is accounted for as an operating lease, while the portion attributable to buildings and equipment is accounted for as a capital lease (see Notes G and Q).

In total, the Company received net proceeds aggregating approximately $207 million from these and other miscellaneous sales in December 2002. Of these proceeds, $87.5 million was used to prepay term loans in December 2002. An additional $16.3 million, included in cash at December 31, 2002, was used to prepay term loans in January 2003. See Note G for further information related to the requirements of the senior secured credit facility and use of proceeds.

Initially, the Company also considered the sale of its marine services operations and the Crude Oil Pipeline System. Given the limited divestiture opportunities for the marine services operation, management plans to integrate this business with the Company's wholesale marketing and terminal operations during 2003. With respect to the Crude Oil Pipeline System, management has explored alternatives, but is no longer pursuing a divestiture of this asset.

NOTE F — OPERATING SEGMENTS

The Company's revenues are derived from two major operating segments: (i) Refining and (ii) Retail. Management has identified these segments for managing operations and investing activities. The Refining segment owns and operates six petroleum refineries located in California, Washington, Hawaii, Alaska, North Dakota and Utah. These refineries manufacture gasoline and gasoline blendstocks, jet fuel, diesel fuel, residual fuel oils and other refined products. These products, together with products purchased from third parties, are sold at wholesale through terminal facilities and other locations, primarily in Alaska, California, Nevada, Hawaii, Idaho, Minnesota, North Dakota, Utah, Oregon and Washington. The Refining segment also sells petroleum products to unbranded marketers and occasionally exports products to other markets in the Asia/Pacific area. The Retail segment sells gasoline, diesel fuel and convenience store items through Company-operated retail stations and branded jobber/dealers in 18 western states from Minnesota to Alaska and Hawaii. Retail operates under the Tesoro® and Mirastar® brands. The Company's Mirastar® brand has been developed exclusively for use at Wal-Mart stores in an agreement covering 17 western states. The Company also markets and distributes petroleum products and other supplies and provides services primarily to the marine and offshore exploration and production industries operating in the Gulf of Mexico. These operations, which are conducted through terminals along the Texas and Louisiana Gulf Coast, are reported as "Other" in the tables below.

The operating segments follow the accounting policies used for the Company's Consolidated Financial Statements as described in the summary of significant policies in Note B. Management evaluates the performance of its segments and allocates resources based primarily on segment operating income. Segment operating income includes those revenues and expenses that are directly attributable to management of the respective segment. Intersegment sales are primarily from Refining to Retail made at prevailing market rates. Income taxes, interest and financing costs, interest income, corporate general and administrative expenses and loss on asset sales and impairment are not included in determining segment operating income. Identifiable assets are those utilized by the segment. Corporate assets are principally cash, income taxes receivable and other assets that are not associated with a specific operating segment.

Segment information as of and for each of the three years in the period ended December 31, 2002 is as follows (in millions):

	2002	2001	2000
Revenues			
Refining:			
Refined products	$6,425.7	$4,603.1	$4,499.3
Crude oil resales and other	334.6	248.3	288.9
Retail:			
Fuel	920.4	420.6	249.6
Merchandise and other	132.1	70.7	55.4
Other	132.2	172.9	186.5
Intersegment sales from Refining to Retail	(825.7)	(333.9)	(212.9)
Total Revenues	$7,119.3	$5,181.7	$5,066.8
Segment Operating Income			
Refining	$ 72.9	$ 225.8	$ 191.1
Retail	(12.3)	25.0	(1.7)
Other	2.3	10.3	10.1
Total Segment Operating Income	62.9	261.1	199.5
Corporate and Unallocated Costs	(73.2)	(60.6)	(46.1)
Loss on Asset Sales and Impairment	(8.4)	(1.8)	—
Operating Income (Loss)	(18.7)	198.7	153.4
Interest and Financing Costs, Net of Capitalized Interest	(166.1)	(52.8)	(32.7)
Interest Income	3.5	1.0	2.8
Earnings (Loss) Before Income Taxes	$ (181.3)	$ 146.9	$ 123.5
Depreciation and Amortization			
Refining	$ 104.2	$ 63.1	$ 57.6
Retail	16.9	11.1	6.6
Other	3.1	2.9	2.7
Corporate	6.5	2.8	2.4
Total Depreciation and Amortization	$ 130.7	$ 79.9	$ 69.3
Capital Expenditures(a)			
Refining	$ 150.9	$ 140.0	$ 56.5
Retail	40.6	43.2	31.0
Other	2.5	3.1	3.2
Corporate	9.5	23.2	3.3
Total Capital Expenditures	$ 203.5	$ 209.5	$ 94.0

(a) Excludes asset acquisitions of $932 million in 2002 and $783 million in 2001 (see Note D).

	2002	2001	2000
Identifiable Assets			
Refining	$3,118.1	$2,164.9	$1,245.6
Retail	287.8	283.8	149.6
Other	68.4	62.0	76.8
Corporate	284.5	151.6	71.6
Total Assets	$3,758.8	$2,662.3	$1,543.6

NOTE G — DEBT

Debt at December 31, 2002 and 2001 consisted of the following (in millions):

	2002	2001
Credit Facility — Tranche A Term Loan	$ 194.2	$ 175.0
Credit Facility — Tranche B Term Loan	723.8	450.0
9⅝% Senior Subordinated Notes Due 2012	450.0	—
9⅝% Senior Subordinated Notes Due 2008	215.0	215.0
9% Senior Subordinated Notes Due 2008 (net of unamortized discount of $2.1 in 2002 and $2.4 in 2001)	297.9	297.6
Junior Subordinated Notes (net of unamortized discount of $83.0)	67.0	—
Other, primarily capital leases	28.8	9.3
Total debt	1,976.7	1,146.9
Less current maturities	70.0	34.4
Debt less current maturities	$1,906.7	$1,112.5

Aggregate maturities of outstanding debt for each of the five years following December 31, 2002 were as follows: 2003 — $70.0 million; 2004 — $53.8 million; 2005 — $53.8 million; 2006 — $65.0 million; and 2007 — $683.8 million. Maturities in 2003 include $16.3 million in required prepayments resulting from proceeds from assets sales (see Note E). Gross borrowings and repayments under revolving credit lines and interim facilities amounted to $624 million, $958 million and $866 million in 2002, 2001 and 2000, respectively.

Senior Secured Credit Facility

On May 17, 2002, the Company amended and restated its senior secured credit facility to increase the facility to $1.275 billion from $1.0 billion to partially fund the acquisition of the California Assets. The terms and conditions of this credit facility were subsequently amended on September 30, 2002 to reflect modified financial tests. The amendment also, among other things, increased the amount of proceeds from asset sales or equity offerings the Company must receive and limits capital expenditures. The credit facility was further amended in December 2002 (as amended, the "Credit Facility"), giving flexibility to the terms and the timing of the required proceeds from asset sales or equity offerings. Under the revised terms of the Credit Facility, the Company agreed to pay certain fees and to increase the interest rate on borrowings.

The Credit Facility currently consists of a five-year $225 million revolving credit facility (with a $150 million sublimit for letters of credit), a five-year tranche A term loan and a six-year tranche B term loan. As of December 31, 2002, the Company had no borrowings and $60 million in letters of credit outstanding under the revolving credit facility, resulting in total unused credit available of $165 million. In addition to the

Credit Facility, the Company has a $12 million uncommitted letter of credit line with a bank, under which no amounts were outstanding as of December 31, 2002.

The Credit Facility is guaranteed by substantially all of the Company's active domestic subsidiaries and is secured by substantially all of the Company's material present and future assets, as well as all material present and future assets of the Company's domestic subsidiaries (with certain exceptions for pipeline, retail and marine services assets) and is additionally secured by a pledge of all of the stock of all current and future active domestic subsidiaries and 66% of the stock of the Company's current and future foreign subsidiaries.

At December 31, 2002, interest rates were 6.77% on the tranche A term loan and 8.5% on the tranche B term loan. Borrowings bear interest at either a base rate (4.25% at December 31, 2002) or a eurodollar rate (1.77% at December 31, 2002), plus an applicable margin. From September 30, 2002 to March 31, 2004, the applicable margins on the tranche A term loan and the revolving credit facility will be 3% in the case of the base rate and 4% in the case of the eurodollar rate and 3.5% in the case of the base rate and 4.5% in the case of the eurodollar rate for the tranche B term loan. Additionally, the tranche B eurodollar rate is deemed to be no less than 3.0%. Subsequent to March 31, 2004, borrowing rates under the tranche A term loan and the revolving credit facility will vary in relation to the Company's senior debt to EBITDA ratio. The Credit Facility interest rates also include an additional 1% interest rate on the tranche A term loan, tranche B term loan and revolving credit facility from September 30, 2002 to March 31, 2004 and thereafter until the Company's debt-to-capital ratio falls to no greater than 0.55 to 1.00. The first additional interest payment is due September 30, 2003 and quarterly thereafter. The Company is charged various fees and expenses in connection with the Credit Facility, including commitment fees and various letter of credit fees.

The Credit Facility requires the Company to meet certain financial covenants, some of which use a measure of cash flow called EBITDA, as defined in the Credit Facility. The financial covenants specify thresholds of the following ratios which use EBITDA: senior debt to EBITDA, EBITDA to fixed charges and EBITDA to interest expense. The initial calculations of these ratios are to be made when the Company issues its financial results for the quarter ending September 30, 2003, using the immediately preceding four quarters. In addition, the financial covenants set a maximum threshold for total debt to total capitalization ratio, as defined in the Credit Facility, each quarter-end commencing June 30, 2002. The Credit Facility requires a minimum cumulative consolidated EBITDA amount of $90 million and $270 million for the nine-month period ending March 31, 2003 and the twelve-month period ending June 30, 2003, respectively. The Credit Facility also requires a minimum consolidated quick ratio, as defined in the Credit Facility, each month-end beginning October 31, 2002 through June 30, 2003. The Credit Facility limits the Company's capital expenditures and refinery turnaround spending to no more than $253.5 million in the year 2002, $237.5 million for the twelve-month period ending June 30, 2003 and $210 million in the calendar year 2003 and each year thereafter unless the Company's debt-to-capital ratio falls below 0.58 to 1.00. Under the terms of the Credit Facility, the Company is not permitted to declare or pay cash dividends on the Company's common stock or repurchase shares of its common stock through December 31, 2003. Beginning January 1, 2004, the terms allow for payment of cash dividends on the Company's common stock and repurchase of shares of its common stock, not to exceed $15 million in any year. The Credit Facility contains other covenants and restrictions customary in credit arrangements of this kind. Noncompliance with the covenants constitutes an event of default and, if not cured by a waiver or amendment, would permit the lenders to accelerate the maturity of the Credit Facility, refuse to advance any additional funds under the Credit Facility and exercise the lenders' remedies under the Credit Facility, and by reason of cross-default provisions, indebtedness under the Company's indentures and other indebtedness could also become immediately due and payable.

The Company satisfied all of the financial covenants under the Credit Facility for the period ended December 31, 2002, as well as the requirement to complete asset sales resulting in net proceeds of at least $200 million prior to March 31, 2003 (see Note E). In December 2002, $87.5 million of the asset sales proceeds were used to prepay term loans. An additional $16.3 million, included in cash at year-end, was used to prepay term loans in January 2003, and therefore was included in current maturities of long-term debt as of December 31, 2002. Net proceeds from asset sales or equity offerings received in 2003 up to the date the Company issues financial results for the quarter ending September 30, 2003, are required to be applied in full to prepay the term loans.

See Note A for information on a proposed refinancing and other matters.

9⅝% Senior Subordinated Notes Due 2012

In April 2002, the Company issued $450 million principal amount of 9⅝% Senior Subordinated Notes due April 1, 2012 ("9⅝% Notes Due 2012"). The 9⅝% Notes Due 2012 have a ten-year maturity with no sinking fund requirements and are subject to optional redemption by the Company after five years at declining premiums. In addition, the Company, for the first three years, may redeem up to 35% of the principal amount at a redemption price of 109.625% with proceeds of certain equity issuances. The indenture for the 9⅝% Notes Due 2012 contains covenants and restrictions which are customary for notes of this nature. The restrictions under the indenture are less restrictive than those in the Credit Facility. To the extent the Company's fixed charge coverage ratio, as defined in the indenture, allows for the incurrence of additional indebtedness, the Company is allowed to pay cash dividends on Common Stock and repurchase shares of Common Stock. The 9⅝% Notes Due 2012 are guaranteed by substantially all of the Company's active domestic subsidiaries. The proceeds from the 9⅝% Notes Due 2012 and accrued interest were used to partially fund the acquisition of the California Assets.

9⅝% Senior Subordinated Notes Due 2008

In November 2001, the Company issued $215 million principal amount of 9⅝% Senior Subordinated Notes due November 1, 2008 ("9⅝% Notes Due 2008"). The 9⅝% Notes Due 2008 have a seven-year maturity with no sinking fund requirements and are subject to optional redemption by the Company after four years at declining premiums. The Company, for the first three years, may redeem up to 35% of the principal amount at a redemption price of 109.625% with net cash proceeds of one or more equity offerings. The indenture for the 9⅝% Notes Due 2008 contains covenants and restrictions which are customary for notes of this nature. The restrictions under the indenture are less restrictive than those in the Credit Facility. To the extent the Company's fixed charge coverage ratio, as defined in the indenture, allows for the incurrence of additional indebtedness, the Company is allowed to pay cash dividends on Common Stock and repurchase shares of Common Stock. The 9⅝% Notes Due 2008 are guaranteed by substantially all of the Company's active domestic subsidiaries.

9% Senior Subordinated Notes Due 2008

In 1998, the Company issued $300 million principal amount of 9% Senior Subordinated Notes due 2008, Series B ("9% Notes Due 2008"). The 9% Notes Due 2008 have a ten-year maturity without sinking fund requirements and are subject to optional redemption by the Company beginning in July 2003 at declining premiums. The indenture for the 9% Notes Due 2008 contains covenants and restrictions which are customary for notes of this nature. The restrictions under the indenture are less restrictive than those in the Credit Facility. To the extent the Company's fixed charge coverage ratio, as defined in the indenture, allows for the incurrence of additional indebtedness, the Company is allowed to pay cash dividends on Common Stock and repurchase shares of Common Stock. The effective interest rate on the 9% Notes Due 2008 is 9.16%, after giving effect to the discount at the date of issue. The 9% Notes Due 2008 are guaranteed by substantially all of the Company's active domestic subsidiaries.

Junior Subordinated Notes

In connection with the California Assets acquisition, the Company issued to the seller two ten-year junior subordinated notes with face amounts aggregating $150 million. The notes consist of: (i) a $100 million junior subordinated note, due July 2012, which is non-interest bearing for the first five years and carries a 7.5% interest rate for the remaining five-year period, and (ii) a $50 million junior subordinated note, due July 2012, which has no interest payment in year one and bears interest at 7.47% for the second through the fifth years and 7.5% for years six through ten. The two junior subordinated notes with face amounts of $100 million and $50 million were initially recorded at a combined present value of approximately $61 million, discounted at rates of 15.625% and 14.375%, respectively. The discount is being amortized over the terms of the notes.

Capital Leases

On December 31, 2002, the Company sold and leased-back 30 retail stations under leases with initial terms of 17 years, with four 5-year renewal options. The portions of the leases attributable to land were classified as operating leases, while the portions attributable to depreciable buildings and equipment were classified as capital leases with a present value of minimum lease payments totaling $23.2 million. In addition, the Company has other capital leases for tugs and barges used in the transportation of petroleum products.

At December 31, 2002 and 2001, the cost of assets under capital leases was $35.3 million gross (accumulated amortization of $7.6 million) and $9.3 million gross (accumulated amortization of $3.7 million), respectively. Capital lease obligations included in debt totaled $28.8 million and $6.6 million at December 31, 2002 and 2001, respectively. Amortization of the cost of assets under capital leases is included in depreciation and amortization in the Statements of Consolidated Operations.

Future minimum annual lease payments as of December 31, 2002 for capital leases were as follows (in millions):

2003	$ 4.5
2004	4.5
2005	4.4
2006	4.1
2007	3.8
Thereafter	35.9
Total minimum lease payments	57.2
Less amount representing interest	28.4
Capital lease obligations	$28.8

NOTE H — STOCKHOLDERS' EQUITY

In March 2002, the Company completed a public offering of 23 million shares of Common Stock. The net proceeds from the stock offering of $245.1 million, after deducting underwriting fees and offering expenses, were used to partially fund the acquisition of the California Assets.

In July 1998, the Company issued 10,350,000 Premium Income Equity Securities, representing fractional interests in the Company's 7.25% Mandatorily Convertible Preferred Stock, receiving gross proceeds of $165 million. Effective July 1, 2001, these securities automatically converted into 10,350,000 shares of Common Stock. The final quarterly cash dividends were paid on July 2, 2001.

The Company was authorized to repurchase up to 3 million shares of Common Stock, which may be used to meet employee benefit plan requirements and for other corporate purposes. In 2000, the Company repurchased 1.6 million shares of Common Stock for $15.5 million. In 2001, the Company repurchased an additional 304,000 shares of its Common Stock for $3.5 million, bringing the cumulative shares repurchased under the program to 1,931,400. In 2002, the Company did not repurchase any shares under the program. Under the terms of the Credit Facility, the Company is not permitted to declare or pay cash dividends on the Company's Common Stock or repurchase shares of its Common Stock through December 31, 2003. Beginning January 1, 2004, the terms allow for payment of cash dividends on the Company's Common Stock and repurchase of shares of its Common Stock, not to exceed $15 million in any year.

See Note P for information relating to stock-based compensation and Common Stock reserved for exercise of options.

NOTE I — INCOME TAXES

The income tax provision (benefit) was comprised of the following (in millions):

	2002	2001	2000
Current:			
Federal	$(60.8)	$17.7	$24.2
State	(6.8)	5.7	4.6
Deferred:			
Federal	8.5	32.9	19.4
State	(5.2)	2.6	2.0
Income Tax Provision (Benefit)	$(64.3)	$58.9	$50.2

Deferred income taxes and benefits are provided for differences between financial statement carrying amounts of assets and liabilities and their respective tax bases. Temporary differences and the resulting deferred tax liabilities and assets at December 31, 2002 and 2001 are summarized as follows (in millions):

	2002	2001
Current Deferred Federal Tax Assets and Liabilities:		
LIFO inventory	$ (25.8)	$ (9.2)
Accrued pension and other postretirement benefits	5.2	2.7
Other accrued employee costs	4.8	3.1
Other accrued liabilities	10.2	6.3
Current Deferred State Tax Assets, Net	2.4	0.4
Current Deferred Tax Asset (Liability), Net	$ (3.2)	$ 3.3
Noncurrent Deferred Federal Tax Assets and Liabilities:		
Accelerated depreciation and property related items	$(205.8)	$(140.2)
Deferred maintenance costs, including refinery turnarounds	(18.2)	(13.4)
Amortization of intangible assets	(30.3)	(0.2)
Net operating loss carryforwards	55.2	—
Accrued pension and other postretirement benefits	47.2	24.4
Alternative minimum tax credit	36.1	—
Accrued environmental remediation liabilities	11.6	7.8
Other	(11.1)	5.2
Noncurrent Deferred State Tax Liability, Net	(13.4)	(20.5)
Noncurrent Deferred Tax Liability, Net	$(128.7)	$(136.9)

The realization of deferred tax assets is dependent upon the Company's ability to generate future taxable income. Although realization is not assured, the Company believes it is more likely than not that the deferred tax assets will be realized and therefore no valuation allowance was recorded at December 31, 2002.

The acquisition of the California Assets in 2002 did not result in any net deferred tax assets or liabilities. In 2001, the Mid-Continent Acquisition described in Note D resulted in net deferred federal tax assets of $8.0 million and net deferred state tax assets of $1.1 million as of the dates of acquisition. The net deferred federal and state tax assets were increased by $4.3 million and $0.6 million, respectively, in 2002 in connection with the finalization of the purchase price allocation.

The reconciliation of income tax expense (benefit) at the U.S. statutory rate to the income tax expense (benefit) is as follows (in millions):

	2002	2001	2000
Income Taxes (Benefit) at U.S. Federal Statutory Rate	$(63.5)	$51.4	$43.2
Effect of:			
State income taxes, net of federal income tax effect	(7.8)	5.3	4.3
Expired tax credits	3.9	—	—
Other	3.1	2.2	2.7
Income Tax Provision (Benefit)	$(64.3)	$58.9	$50.2

As of December 31, 2002, the Company had approximately $158 million of Federal net operating loss carryforwards that expire in 2022 and $36 million of alternative minimum tax credits that can be carried forward indefinitely.

The filing of the 2001 tax returns and the carryback of the 2001 net operating loss resulted in the receipt of $48 million of refunds during 2002. In 2002, the Company incurred additional net operating losses, a portion of which were carried back to previous years. The Company's election to carryback the 2002 net operating losses resulted in the loss of $3.9 million of tax credits claimed in earlier years. Income taxes receivable of $41.9 million at December 31, 2002 have been collected in the first quarter of 2003.

NOTE J — RECEIVABLES

Concentrations of credit risk with respect to accounts receivable are influenced by the large number of customers comprising the Company's customer base and their dispersion across various industry groups and geographic areas of operations. The Company performs ongoing credit evaluations of its customers' financial condition and in certain circumstances requires prepayments, letters of credit or other collateral arrangements. The Company's allowance for doubtful accounts is reflected as a reduction of receivables in the Consolidated Balance Sheets and amounted to $3.7 million and $3.2 million at December 31, 2002 and 2001, respectively.

NOTE K — INVENTORIES

Components of inventories at December 31, 2002 and 2001 were as follows (in millions):

	2002	2001
Crude oil and refined products, at LIFO	$402.6	$398.4
Other fuel, oxygenates and by-products, at FIFO	11.2	2.1
Merchandise and other	9.3	7.9
Materials and supplies	38.4	23.4
Total Inventories	$461.5	$431.8

At December 31, 2002 and 2001, inventories valued using LIFO were lower than replacement cost by approximately $120 million and $3 million, respectively. During 2002, certain inventory quantities were reduced, resulting in a liquidation of applicable LIFO inventory quantities carried at lower costs prevailing in previous years. This LIFO liquidation resulted in a decrease in cost of sales of $5 million and a decrease in net loss of approximately $3 million, or $0.05 per share, during 2002.

NOTE L — GOODWILL AND ACQUIRED INTANGIBLES

SFAS No. 142, "Goodwill and Other Intangible Assets", requires that goodwill and other intangibles determined to have an indefinite life are no longer to be amortized but are to be tested for impairment at least annually. See Note B for the effects of the amortization of goodwill in 2001 and 2000. Upon adoption of SFAS No. 142, the Company ceased amortizing goodwill and determined through the required transitional test that its goodwill was not impaired as of January 1, 2002. The Company completed the required annual test for goodwill impairment during the fourth quarter of 2002. Based on the annual test, the Company recognized a loss of $1.2 million to reduce the carrying value of goodwill in the Retail segment. The impairment is included in loss on asset sales and impairment in the Statements of Consolidated Operations. The fair value of the reporting unit was estimated using the expected present value of future cash flows. The impairment resulted from a change in strategy which reduced the estimated future performance of the reporting unit.

The annual evaluation of goodwill impairment involves significant estimates made by management in determining the fair value of reporting units. These estimates are susceptible to change from period to period because management must make assumptions about future cash flows, profitability and other items. It is reasonably possible that changes in estimates could have a material impact in the carrying amount of goodwill in future periods.

The net carrying values of goodwill by operating segments at December 31, 2002 and 2001 were as follows (in millions):

	2002	2001
Refining	$84.0	$86.9
Retail	4.7	5.9
Other	2.4	2.4
Total	$91.1	$95.2

The decrease of $2.9 million in the Refining segment goodwill during 2002 reflects the finalization of the purchase price allocation for the Mid-Continent assets acquired in September 2001. As discussed above, the decrease of $1.2 million in the Retail segment goodwill was due to an impairment loss recognized in the fourth quarter of 2002.

The following table provides the gross carrying amount and accumulated amortization for each major class of acquired intangible assets, excluding goodwill (in millions):

	December 31, 2002			December 31, 2001		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Value	Gross Carrying Amount	Accumulated Amortization	Net Carrying Value
Air emissions credits	$100.7	$ 2.7	$ 98.0	$16.5	$0.2	$16.3
Refinery permits and plans	11.0	0.6	10.4	7.4	0.1	7.3
Customer agreements and contracts	39.8	6.4	33.4	40.3	1.7	38.6
Other intangibles	12.4	3.6	8.8	13.6	2.5	11.1
Total	$163.9	$13.3	$150.6	$77.8	$4.5	$73.3

The intangible assets as of December 31, 2002 included amounts attributable to the California refinery acquired in May 2002. Those amounts are preliminary, pending completion of independent appraisals. Reductions in the gross carrying amounts of customer agreements and contracts and other intangibles reflect the finalization of the purchase price allocation for the Mid-Continent Acquisition.

The weighted average lives of acquired intangible assets are as follows: air emission credits — 28 years; refinery permits and plans — 22 years; customer agreements and contracts — 14 years; and other intangible assets — 12 years.

Amortization expense of acquired intangible assets other than goodwill amounted to $8.8 million and $2.7 million for the years ended December 31, 2002 and 2001, respectively. Estimated aggregate amortization expense for each of the following five years is as follows: 2003 — $10 million; 2004 — $10 million; 2005 — $9 million; 2006 — $8 million; and 2007 — $6 million. These estimates are preliminary, pending completion of independent appraisals of the California refinery.

NOTE M — OTHER ASSETS

Other assets consisted of the following at December 31, 2002 and 2001 (in millions):

	2002	2001
Deferred maintenance costs, including refinery turnarounds, net	$ 62.1	$44.1
Debt issuance costs, net:		
Senior secured credit facility	34.9	16.6
Senior subordinated notes	21.5	13.1
Prepaid pension costs and intangible pension asset	14.3	9.2
Notes receivable from employees	4.3	—
Other assets, net	22.4	10.5
Total Other Assets	$159.5	$93.5

At December 31, 2002, the Company had outstanding notes receivable totaling approximately $2.4 million from an Executive Vice President and a Senior Vice President of the Company. The notes are non-interest bearing and require annual principal payments over terms of five to six years. Two of the notes were issued on June 12, 2002 and one was assumed by the Company in connection with the May 17, 2002 acquisition of the California refinery.

As discussed in Note A, the Company is pursuing discussions regarding possible financing alternatives to replace its senior secured credit facility. If the Company elects to replace or modify its senior secured credit facility, it may be required to write-off all or a portion of the senior secured credit facility debt issuance costs ($34.9 million at December 31, 2002) during the quarter in which the Company replaces or modifies the facility.

NOTE N — ACCRUED LIABILITIES

The Company's current accrued liabilities and noncurrent other liabilities as shown in the Consolidated Balance Sheets at December 31, 2002 and 2001 included the following (in millions):

	2002	2001
Accrued Liabilities — Current:		
Taxes other than income taxes, primarily excise taxes	$ 80.9	$ 87.8
Employee costs	25.6	32.3
Interest	47.6	22.2
Pension benefits	16.8	7.7
Other	28.8	22.9
Total Accrued Liabilities — Current	$199.7	$172.9
Other Liabilities — Noncurrent:		
Pension and other postretirement benefits	$149.2	$ 85.1
MTBE lease termination obligation (see Note D)	31.5	—
Other	46.8	32.3
Total Other Liabilities — Noncurrent	$227.5	$117.4

NOTE O — BENEFIT PLANS

Pension and Other Postretirement Benefits

The Company sponsors defined benefit pension plans, including an employee retirement plan, executive security plans and a non-employee director retirement plan.

For all eligible employees, the Company provides a qualified noncontributory retirement plan ("Retirement Plan"). Plan benefits are based on years of service and compensation. The Company's funding policy is to make contributions at a minimum in accordance with the requirements of applicable laws and regulations, but no more than the amount deductible for income tax purposes. The Company contributed $13 million in 2002 and expects to contribute $17 million in 2003. Retirement plan assets are primarily comprised of common stock and bond funds.

The Company's executive security plans ("ESP Plans") provide certain executive officers and other key personnel with supplemental death or retirement benefits. Such benefits are provided by two nonqualified, noncontributory plans and are based on years of service and compensation. The Company makes contributions to one plan, the "Funded ESP Plan", based upon estimated requirements. Assets of the Funded ESP plan consist of a group annuity contract. The Company contributed $3 million in 2002 and expects to contribute $2 million in 2003.

The Company had previously established an unfunded non-employee director retirement plan ("Director Retirement Plan") which provided eligible directors retirement payments upon meeting certain age and other requirements. In 1997, the Director Retirement Plan was frozen with accrued benefits of current directors transferred to the Company's Board of Directors Phantom Stock Plan ("Phantom Stock Plan") (see Note P). After the amendment and transfer, only those retired directors or beneficiaries who had begun to receive benefits remained participants in the Director Retirement Plan.

The Company provides to retirees who were participating in the Company's group insurance program at retirement, health care and, to those who qualify, life insurance benefits. Health care is provided to qualified dependents of participating retirees. These benefits are provided through unfunded, defined benefit plans or through contracts with area health-providers on a premium basis. The health care plans are contributory, with retiree contributions adjusted periodically, and contain other cost-sharing features such as deductibles and coinsurance. The life insurance plan is noncontributory. The Company funds its share of the cost of postretirement health care and life insurance benefits on a pay-as-you go basis.

Changes in benefit obligations, plan assets and the funded status of the pension plans and other postretirement benefits, reconciled to amounts in the Consolidated Balance Sheets as of December 31, 2002 and 2001, are presented below (in millions):

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Change in benefit obligations:				
Benefit obligations at beginning of year	$129.3	$108.1	$ 80.2	$ 52.3
Service cost	13.5	8.3	6.1	2.9
Interest cost	10.9	8.5	7.1	4.3
Actuarial loss	23.4	0.6	15.4	8.3
Benefits paid	(11.3)	(6.7)	(2.0)	(1.9)
Curtailments and settlements	(0.8)	—	—	—
Plan amendments	0.7	9.0	—	2.0
Acquisitions	19.0	1.5	31.5	12.3
Benefit obligations at end of year	184.7	129.3	138.3	80.2
Change in plan assets:				
Fair value of plan assets at beginning of year	73.6	74.4	—	—
Actual return on plan assets	(5.9)	(2.7)	—	—
Employer contributions	16.3	8.5	—	—
Benefits paid	(11.2)	(6.6)	—	—
Fair value of plan assets at end of year	72.8	73.6	—	—
Funded status	(111.9)	(55.7)	(138.3)	(80.2)
Unrecognized prior service cost	8.9	9.2	2.4	2.6
Unrecognized net actuarial loss	59.3	27.6	27.8	12.8
Accrued benefit cost	$(43.7)	$(18.9)	$(108.1)	$(64.8)
Amounts included in Consolidated Balance Sheets:				
Accrued and other liabilities	$(58.0)	$(28.1)	$(108.1)	$(64.8)
Prepaid pension costs	7.7	9.2	—	—
Intangible asset	6.6	—	—	—
Net amount recognized	$(43.7)	$(18.9)	$(108.1)	$(64.8)

At December 31, 2002, the accumulated benefit obligation of the Retirement Plan exceeded the fair value of plan assets and the Company recognized an additional minimum liability and an intangible asset of $6.6 million.

In 2001, the Company announced amendments to the pension plan by adding a lump-sum distribution option and enhanced early retirement provisions for long-term employees. These changes, along with changes to comply with new regulations, increased the Company's pension benefit obligation by $9 million and postretirement benefit obligation by $2 million during 2001.

In the first quarter of 2003, the Company offered voluntary enhanced retirement benefits to 91 qualified employees. These enhanced benefits, which are being offered for only a short period of time, will result in additional liabilities and a charge to expense upon acceptance of the offers in the 2003 first quarter. The amount, which cannot presently be determined because it depends upon the number of acceptances, could range from $12 million to $24 million pretax.

SFAS No. 132 requires companies to disclose the aggregate benefit obligation and plan assets of all plans in which the obligations exceed assets. At December 31, 2002, the projected benefit obligations, accumulated benefit obligations and fair values of plan assets aggregated $165.6 million, $113.8 million and $55.8 million, respectively, combined for the Retirement Plan, the unfunded ESP Plan and the Directors' Retirement Plan. At December 31, 2001, the projected benefit obligations, accumulated benefit obligations and fair values of plan assets aggregated $112.8 million, $86.3 million and $57.6 million, respectively, for these plans in total. The assets of the Funded ESP Plan exceeded its accumulated benefit obligation at year-end 2002 and 2001.

The components of pension and postretirement benefit expense included in the Consolidated Statements of Operations for the years ended December 31, 2002, 2001 and 2000 were as follows (in millions):

	Pension Benefits			Other Postretirement Benefits		
	2002	2001	2000	2002	2001	2000
Components of net periodic benefit expense:						
Service cost	$13.5	$ 8.3	$ 6.1	$ 6.1	$2.9	$1.6
Interest cost	10.9	8.5	7.5	7.1	4.3	3.2
Expected return on plan assets	(6.6)	(6.3)	(5.9)	—	—	—
Amortization of prior service cost	1.0	—	—	0.2	—	—
Recognized net actuarial loss (gain)	3.6	2.8	2.2	0.3	0.2	(0.2)
Curtailments and settlements	(0.2)	—	0.5	—	—	—
Net periodic benefit expense	$22.2	$13.3	$10.4	$13.7	$7.4	$4.6

Significant assumptions included in the estimation of the Company's pension and other postretirement benefits obligations are as follows:

	Pension Benefits			Other Postretirement *Benefits*		
	2002	2001	2000	2002	2001	2000
Assumed weighted average % as of December 31:						
Discount rate	6.34	7.18	7.58	6.50	7.25	7.50
Rate of compensation increase	4.12	5.00	5.40	4.00	4.75	5.75
Expected return on plan assets	8.15	8.17	8.26	—	—	—

The weighted average annual assumed rate of increase in the per capita cost of covered health care benefits was assumed to be 7.25% for retirees younger than 65 for 2001, decreasing gradually to 5% by the year 2010, and an initial 9.1% for retirees 65 and older, decreasing gradually to 5.5% by the year 2010 and remaining level thereafter. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care and life insurance plans. A one-percentage-point change in assumed health care cost trend rates could have the following effects (in millions):

	1-Percentage-Point Increase	1-Percentage Point Decrease
Effect on total of service and interest cost components	$ 2.6	$ (2.0)
Effect on postretirement benefit obligations	$26.7	$(20.7)

Thrift Plan and Retail Savings Plan

The Company sponsors an employee thrift plan ("Thrift Plan") that provides for contributions, subject to certain limitations, by eligible employees into designated investment funds with a matching contribution by the Company. Employees may elect tax-deferred treatment in accordance with the provisions of Section 401(k) of the Internal Revenue Code. Effective November 1, 2001, the Thrift Plan was amended to change the Company's 100% matching contribution, from a maximum of 6% to 7% of the employee's eligible earnings, with at least 50% of the Company's matching contribution directed for initial investment in Common Stock of the Company. The maximum matching contribution is 6% for employees covered by the collective bargaining agreement at the California refinery. Participants may transfer out of Tesoro's Common Stock at any time, but are limited to four such transfers each calendar year. The Company's contributions to the Thrift Plan amounted to $11.1 million, $6.5 million and $5.4 million during 2002, 2001 and 2000, respectively, of which $2.4 million and $3.4 million consisted of treasury stock reissuances in 2002 and 2001, respectively. There were no similar reissuances in 2000.

Effective January 1, 2001, the Company began sponsoring a new savings plan, in lieu of the Thrift Plan, for eligible retail employees who have completed one year of service and have worked at least 1,000 hours within that time. Eligible employees receive a mandatory employer contribution equal to 3% of eligible earnings. If employees elect to make pretax contributions, the Company also contributes an employer match contribution equal to $0.50 for each $1.00 of employee contributions, up to 6% of eligible earnings. At least 50% of the mandatory and matching employer contributions must be directed for initial investment in Common Stock of the Company. Participants may transfer out of Tesoro's Common Stock at any time, but are limited to four such transfers each calendar year. The Company's contributions amounted to $0.4 million and $0.2 million during 2002 and 2001, respectively, of which $0.1 million consisted of treasury stock reissuances in both 2002 and 2001.

NOTE P — STOCK-BASED COMPENSATION

Incentive Stock Plans

The Company has three employee incentive stock plans, the Key Employee Stock Option Plan, as amended ("1999 Plan"), the Amended and Restated Executive Long-Term Incentive Plan ("1993 Plan") and Amended Incentive Stock Plan of 1982 ("1982 Plan"). In addition, the Company has the 1995 Non-Employee Director Stock Option Plan ("1995 Plan"). At December 31, 2002, the Company had 7,536,427 shares of unissued Common Stock reserved for these employee incentive stock plans and non-employee director plan.

Under the 1993 Plan, shares of Common Stock may be granted in a variety of forms, including restricted stock, incentive stock options, nonqualified stock options, stock appreciation rights and performance share and performance unit awards. At the Company's 2002 Annual Meeting of Stockholders held in June 2002, an amendment was approved by the stockholders which increased the number of shares available for grant under the 1993 Plan from 5,250,000 to 7,250,000. Stock options may be granted at exercise prices not less than the fair market value on the date the options are granted. The options granted generally become exercisable after one year in 25% or 33% increments per year and expire ten years from the date of grant. Subject to stockholder approval, the Board of Directors expects to extend the expiration date of the 1993 Plan from September 15, 2003 to September 15, 2008. At December 31, 2002, the Company had 1,262,614 shares available for future grants under the 1993 Plan.

The 1999 Plan provides for the granting of stock options to eligible persons employed by the Company who are not executive officers of the Company. Under the 1999 Plan, the total number of stock options that may be granted is 800,000 shares. Stock options may be granted at not less than the fair market value on the date the options are granted and generally become exercisable after one year in 25% increments. The options expire after ten years from the date of grant. The Board of Directors may amend, terminate or suspend the 1999 Plan at any time. At December 31, 2002, the Company had 50,500 shares available for future grants under the 1999 Plan.

The 1982 Plan expired in 1994 as to issuance of stock appreciation rights, stock options and stock awards; however, grants made before the expiration date, that have not been fully exercised, remain outstanding pursuant to their terms.

The 1995 Plan provides for the grant of nonqualified stock options to eligible non-employee directors of the Company. At the Company's 2002 Annual Meeting of Stockholders held in June 2002, an amendment was approved by the stockholders which increased the number of shares available for grant under the 1995 Plan from 150,000 to 300,000. These automatic, non-discretionary stock options are granted at an exercise price equal to the fair market value per share of the Company's Common Stock as of the date of grant. The term of each option is ten years, and an option first becomes exercisable six months after the date of grant. The 1995 Plan will terminate as to issuance of stock options in February 2005. At December 31, 2002, the Company had 121,000 options outstanding and 156,000 shares available for future grants under the 1995 Plan.

A summary of stock option activity for all plans is set forth below (shares in thousands):

	Number of Options Outstanding	Weighted-Average Exercise Price
Outstanding January 1, 2000	3,753.4	$13.17
Granted	1,492.0	10.01
Exercised	(28.7)	7.42
Forfeited and expired	(193.5)	14.03
Outstanding December 31, 2000	5,023.2	12.23
Granted	98.0	13.18
Exercised	(249.7)	6.12
Forfeited and expired	(20.4)	9.21
Outstanding December 31, 2001	4,851.1	12.57
Granted	1,368.0	8.20
Exercised	(0.7)	10.03
Forfeited and expired	(151.1)	12.58
Outstanding December 31, 2002	6,067.3	11.59

The following table summarizes information about stock options outstanding under all plans at December 31, 2002 (shares in thousands):

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable	Weighted-Average Exercise Price
$3.86 to $7.55	721.3	9.6 years	$4.74	36.3	$5.97
$7.56 to $11.24	2,038.8	7.0 years	9.66	1,118.1	9.59
$11.25 to $14.94	2,219.3	6.2 years	13.29	1,514.6	13.33
$14.95 to $18.63	1,087.9	5.6 years	16.28	1,087.8	16.28
$3.86 to $18.63	6,067.3	6.7 years	11.59	3,756.8	13.00

At December 31, 2002, 2001 and 2000, exercisable stock options totaled 3.8 million, 3.1 million and 2.4 million, respectively.

Phantom Stock Plan

Under the Phantom Stock Plan, a yearly credit of $7,250 is made in units to an account ("Account") of each non-employee director, based upon the closing market price of the Company's Common Stock on the date of credit. In addition, a director may elect to have the value of his cash retainer fee deposited quarterly into the Account in units. Retiring directors who are committee chairpersons receive an additional $5,000 credit to their accounts. Certain non-employee directors also received a credit in their Account in 1997 arising from the transfer of their lump-sum accrued benefit under the frozen Director Retirement Plan. The value of each Account balance, which is a function of the amount, if any, by which the market value of the Company's Common Stock changes, is payable in cash at termination (if vested with three years of service) or at retirement, death or disability. The Company's results of operations included a credit of $299,000 in 2002 and expenses of $144,000 and $201,000 in 2001 and 2000, respectively, related to the Phantom Stock Plan.

Phantom Stock Agreement

The chief executive officer of the Company holds 175,000 phantom stock options, which were granted in 1997 with a term of ten years at 100% of the fair value of the Company's Common Stock on the grant date, or $16.9844 per share. At December 31, 2002, all of the 175,000 phantom stock options were exercisable. Upon exercise, the chief executive officer would be entitled to receive in cash the difference between the fair market value of the Common Stock on the date of the phantom stock option grant and the fair market value of Common Stock on the date of exercise. At the discretion of the Compensation Committee of the Board of Directors, these phantom stock options may be converted to traditional stock options under the 1993 Plan. No compensation expense has been recognized related to this award.

Pro Forma

For information related to the pro forma effects had compensation cost been determined based on fair values at the grant dates of awards in accordance with SFAS No. 123, see Note B.

NOTE Q — COMMITMENTS AND CONTINGENCIES

Operating Leases

The Company has various noncancellable operating leases related to land, buildings, equipment, retail facilities and ship charters. These leases have remaining primary terms up to 25 years, with terms of certain rights-of-way extending up to 28 years, and generally contain multiple renewal options.

In December 2002, the Company sold and leased back 30 retail stations under leases with initial terms of 17 years, and four 5-year renewal options. The portion of each lease attributed to land has been classified as an operating lease, while the portion attributed to depreciable buildings and equipment has been classified as a capital lease (see Note G).

The Company has an agreement with Wal-Mart to build and operate retail fueling facilities on sites at selected existing and future Wal-Mart store locations in the western United States. Under the agreement with Wal-Mart, each site is subject to a lease with a ten-year primary term and an option, exercisable at the Company's discretion, to extend a site's lease for two additional terms of five years each.

The Company has long-term charters through July 2010 for two U.S. flagged ships, used to transport crude oil and products. The aggregate annual commitments on these charters total $25 million to $29 million over the remaining term, which include operating expenses that increase annually from $13 million to $16 million over the remaining period.

In the fourth quarter of 2001, the Company sold 18 gas-fired power generators that had been purchased and installed at the Washington refinery. At the same time, the Company leased back these generators for a three-year term. The lease contains extension and purchase options at fair market value. The annual lease commitments, included in the table below, amount to $3.1 million for each of the three years. The $15 million cost to purchase the generators was reported in capital expenditures and the $15 million proceeds from their sale is reported as proceeds from asset sales in the Statement of Consolidated Cash Flows in 2001.

The Company leases its corporate headquarters from a limited partnership, in which the Company owns a 50% limited interest. The initial term of the lease is through 2014 with two five-year renewal options. Included in total rent expense below are lease payments and operating costs paid to the partnership totaling $2.1 million, $2.5 million and $1.8 million in 2002, 2001 and 2000, respectively. The Company accounts for its interest in the partnership using the equity method of accounting. As such, the partnership's assets, primarily land and buildings, totaling approximately $17 million and debt of approximately $13 million are not included in the accompanying Consolidated Financial Statements.

Future minimum annual lease payments as of December 31, 2002, for operating leases having initial or remaining noncancellable lease terms in excess of one year were as follows (in millions):

	Ship Charters	Other
2003	$29.8	$37.4
2004	25.9	29.8
2005	26.9	24.3
2006	27.6	19.7
2007	28.0	19.2
Thereafter	71.8	143.3

Total rental expense for short-term and long-term operating leases, excluding marine charters, amounted to approximately $46 million in 2002, $34 million in 2001, and $26 million in 2000. The Company also enters into various short-term charters for vessels to transport refined products from the Company's refineries and terminals and to deliver products to customers. Total marine charter expense was $54 million in 2002, $40 million in 2001 and $42 million in 2000. For information related to capital leases, see Note G.

Other Commitments

In the normal course of business, the Company has long-term commitments to purchase services, such as electricity, water, hydrogen, nitrogen, oxygen and sulfuric acid for use by certain of its refineries. The minimum annual payments under these contracts are estimated to total $26 million in 2003, $25 million in 2004, $14 million in 2005, $14 million in 2006, and $14 million in 2007. The remaining minimum commitment totals approximately $37 million over 10 years. The Company also has a power supply agreement at the California refinery which requires minimum payments that vary, based on market prices for electricity, over the next 10 years. The Company paid approximately $57 million, $15 million and $14 million in 2002, 2001 and 2000, respectively, under these contracts.

Environmental and Other Matters

The Company is a party to various litigation and contingent loss situations, including environmental and income tax matters, arising in the ordinary course of business. The Company has made accruals in accordance with SFAS No. 5, "Accounting for Contingencies", in order to provide for these matters. The ultimate effects of these matters cannot be predicted with certainty, and related accruals are based on management's best estimates, subject to future developments. Although the resolution of certain of these matters could have a material adverse impact on interim or annual results of operations, the Company believes that the outcome of these matters will not result in a material adverse effect on its liquidity or consolidated financial position.

In the normal course of business, the Company is subject to audits by Federal, state and local taxing authorities. Audit examinations have resulted in proposed adjustments that are subject to further appeal. It is possible that such audits could result in claims against the Company in excess of liabilities currently recorded. Management believes, however, that the ultimate resolution of these matters will not materially affect the Company's consolidated financial position or results of operations.

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which change frequently, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites or install additional controls or other modifications or changes in use for certain emission sources.

Environmental Remediation Liabilities

The Company is currently involved with the U.S. Environmental Protection Agency ("EPA") regarding a waste disposal site near Abbeville, Louisiana. The Company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA" or "Superfund") at this location. Although the Superfund law may impose joint and several liability upon each party at the site, the extent of the Company's allocated financial contributions for cleanup is expected to be de minimis based upon the number of companies, volumes of waste involved and total estimated costs to close the site. The Company believes, based on these considerations and discussions with the EPA, that its liability at the Abbeville site will not exceed $25,000.

Soil and groundwater conditions at the California refinery may require substantial expenditures over time. The Company's current estimate of costs to address environmental liabilities including soil and groundwater conditions at the refinery in connection with various projects, including those required pursuant to orders by the California Regional Water Quality Control Board, is approximately $73 million, of which approximately $31 million is anticipated to be incurred through 2006 and the balance thereafter. The Company believes that it will be entitled to indemnification for approximately $63 million of such costs, directly or indirectly, from former owners or operators of the refinery (or their successors) under two separate indemnification agreements. Additionally, if remediation expenses are incurred in excess of the indemnification, the Company expects to receive coverage under one or both of the environmental insurance policies discussed in Note D.

In connection with the acquisition of the Hawaii refinery, the Company received an indemnity from the seller for environmental costs arising out of conditions which existed at or prior to the Hawaii refinery acquisition. This indemnification, which is in effect until 2008, has $4.4 million remaining as of December 31, 2002.

The Company is currently involved in remedial responses and has incurred cleanup expenditures associated with environmental matters at a number of other sites, including certain of its owned properties. At December 31, 2002, the Company's accruals for environmental expenses totaled approximately $40 million. The Company's accruals for environmental expenses include retained liabilities for prior owned or operated properties, refining, pipeline, terminal and marine services operations and retail service stations. Based on currently available information, including the participation of other parties or former owners in remediation actions, the Company believes these accruals are adequate.

Environmental Capital

In February 2000, the EPA finalized new regulations pursuant to the Clean Air Act requiring reduction in the sulfur content in gasoline beginning January 1, 2004. To meet this revised gasoline standard, the Company currently estimates it will make capital improvements of approximately $37 million through 2006 and an additional $15 million thereafter. This will permit all of the Company's refineries to produce gasoline meeting the limits imposed by the EPA.

The EPA also promulgated new regulations in January 2001 pursuant to the Clean Air Act requiring a reduction in the sulfur content in diesel fuel manufactured for on-road consumption. In general, the new diesel fuel standards will become effective on June 1, 2006. Based on the latest engineering estimates, the Company expects to spend approximately $55 million in capital improvements through 2007. These expenditures, however, do not include the Alaska refinery where the Company has limited demand for low sulfur diesel which presently does not justify the capital investment. The Company expects to meet this demand from other sources.

The Company expects to spend approximately $44 million in additional capital improvements through 2006 to comply with the second phase of the Maximum Achievable Control Technologies standard for petroleum refineries ("Refinery MACT II"), promulgated in April 2002. The Refinery MACT II regulations require new emission controls at certain processing units at several of the Company's refineries. The Company is currently evaluating a selection of control technologies to assure operations flexibility and compatibility with long-term air emission reduction goals.

To meet California's CARB III gasoline requirements, including the mandatory phase out of using the oxygenate known as MTBE, the Company expects to spend approximately $17 million in 2003 at the California refinery. The project should be completed in the first quarter of 2003.

In connection with the 2001 acquisition of the North Dakota and Utah refineries, the Company assumed the sellers' obligations and liabilities under a consent decree among the United States, BP Exploration and Oil Co., Amoco Oil Company and Atlantic Richfield Company. BP entered into this consent decree for both the North Dakota and Utah refineries for various alleged violations. As the new owner of these refineries, the Company is required to address issues, including leak detection and repair, flaring protection and sulfur recovery unit optimization. The Company currently estimates it will spend an aggregate of $7 million to comply with this consent decree. In addition, the Company has agreed to indemnify the sellers for all losses of any kind incurred in connection with the consent decree.

In connection with the 2002 acquisition of the California refinery, subject to certain conditions, the Company also assumed the seller's obligations pursuant to its settlement efforts with the Environmental Protection Agency concerning the Section 114 refinery enforcement initiative under the Clean Air Act, except for any potential monetary penalties, which the seller retains. The Company believes these obligations will not have a material impact on its financial position.

Based on latest estimates, the Company will need to expend additional capital at the California refinery for reconfiguring and replacing above ground storage tank systems and upgrading piping within the refinery. These costs are currently estimated at approximately $130 million through 2007 and an additional estimated $90 million through 2011. Both of these cost estimates are subject to further review and analysis by the Company.

Conditions that require additional expenditures may transpire for various Company sites, including, but not limited to, the Company's refineries, tank farms, retail gasoline stations (operating and closed locations) and petroleum product terminals, and for compliance with the Clean Air Act and other state, federal and local requirements. The Company cannot currently determine the amounts of such future expenditures.

Other Matters

Union Oil Company of California has asserted claims against other refining companies for infringement of patents related to the production of certain reformulated gasoline. The Company's California refinery produces grades of gasoline that might be subject to similar claims. Since the validity of those patents is now being re-examined by the U.S. Patent Office, the Company has not paid or accrued liabilities for patent royalties that might be related to production at the California refinery.

NOTE R — QUARTERLY FINANCIAL DATA (UNAUDITED)

	Quarters				Total Year
	First	Second	Third	Fourth	
	(In millions except per share amounts)				
2002					
Revenues as originally reported	$1,243.2	$1,745.7	$2,173.2	$2,055.5	$7,217.6
Reclassifications	(10.6)	(8.9)	(24.7)	(54.1)	(98.3)
Revenues	$1,232.6	$1,736.8	$2,148.5	$2,001.4	$7,119.3
Operating Income (Loss)	$ (63.2)	$ 9.7	$ 19.4	$ 15.4	$ (18.7)
Net Loss	$ (55.6)	$ (17.9)	$ (15.8)	$ (27.7)	$ (117.0)
Net Loss Per Share:					
Basic	$ (1.15)	$ (0.28)	$ (0.24)	$ (0.43)	$ (1.93)
Diluted	$ (1.15)	$ (0.28)	$ (0.24)	$ (0.43)	$ (1.93)
2001					
Revenues as originally reported	$1,227.3	$1,299.6	$1,412.0	$1,278.9	$5,217.8
Reclassifications	(15.9)	0.7	(6.6)	(14.3)	(36.1)
Revenues	$1,211.4	$1,300.3	$1,405.4	$1,264.6	$5,181.7
Operating Income	$ 43.5	$ 55.6	$ 71.9	$ 27.7	$ 198.7
Net Earnings	$ 21.7	$ 29.5	$ 32.8	$ 4.0	$ 88.0
Net Earnings Per Share:					
Basic	$ 0.61	$ 0.85	$ 0.79	$ 0.10	$ 2.26
Diluted	$ 0.52	$ 0.70	$ 0.79	$ 0.10	$ 2.10

Certain previously reported amounts have been reclassified to conform to the 2002 presentation, principally the reclassification of revenues and cost of sales to report certain crude oil and product purchases and resales on a net basis (see Note B).

The results above include the California Assets operations since mid-May 2002 and the Mid-Continent operations since September 2001.

During the fourth quarter of 2002, the Company incurred a loss on assets sales and impairment totaling $7.9 million, primarily related to the sale of 70 retail stations in northern California and the sale/lease-back of 30 retail stations (see Note E). Also during the fourth quarter of 2002, the Company's income tax benefit was reduced by $6.0 million due to the loss of tax credits claimed in earlier years and other adjustments to estimated liabilities (see Note I).

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information required under this Item will be contained in the Company's 2003 Proxy Statement, incorporated herein by reference. See also Executive Officers of the Registrant under Business in Item 1 hereof.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this Item will be contained in the Company's 2003 Proxy Statement, incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required under this Item will be contained in the Company's 2003 Proxy Statement, incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required under this Item will be contained in the Company's 2003 Proxy Statement, incorporated herein by reference.

ITEM 14. CONTROLS AND PROCEDURES

Within the 90 days prior to the filing date of this report, we carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-14 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company required to be included in our periodic filings under the Exchange Act. Subsequent to the date of this evaluation, there have been no significant changes in our internal controls or in other factors that could significantly affect internal controls, nor were any corrective actions required with regard to significant deficiencies or material weaknesses.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. Financial Statements

The following Consolidated Financial Statements of Tesoro Petroleum Corporation and its subsidiaries are included in Part II, Item 8 of this Form 10-K:

2. Financial Statement Schedules

No financial statement schedules are submitted because of the absence of the conditions under which they are required or because the required information is included in the Consolidated Financial Statements or notes thereto.

3. Exhibits

Exhibit Number	Description of Exhibit
2.1	— Stock Sale Agreement, dated March 18, 1998, among the Company, BHP Hawaii Inc. and BHP Petroleum Pacific Islands Inc. (incorporated by reference herein to Exhibit 2.1 to Registration Statement No. 333-51789).
2.2	— Stock Sale Agreement, dated May 1, 1998, among Shell Refining Holding Company, Shell Anacortes Refining Company and the Company (incorporated by reference herein to the Company's Quarterly Report on Form 10-Q for the period ended March 31, 1998, File No. 1-3473).
2.3	— Stock Purchase Agreement, dated as of October 8, 1999, but effective as of July 1, 1999 among the Company, Tesoro Gas Resources Company, Inc., EEX Operating LLC and EEX Corporation (incorporated by reference herein to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on January 3, 2000, File No. 1-3473).
2.4	— First Amendment to Stock Purchase Agreement dated December 16, 1999, but effective as of October 8, 1999, among the Company, Tesoro Gas Resources Company, Inc., EEX Operating LLC and EEX Corporation (incorporated by reference herein to Exhibit 2.2 to the Company's Current Report on Form 8-K filed on January 3, 2000, File No. 1-3473).
2.5	— Purchase Agreement dated as of December 17, 1999 among the Company, Tesoro Gas Resources Company, Inc. and EEX Operating LLC (Membership Interests in Tesoro Grande LLC) (incorporated by reference herein to Exhibit 2.3 to the Company's Current Report on Form 8-K filed on January 3, 2000, File No. 1-3473).
2.6	— Purchase Agreement dated as of December 17, 1999 among the Company, Tesoro Gas Resources Company, Inc. and EEX Operating LLC (Membership Interests in Tesoro Reserves Company LLC) (incorporated by reference herein to Exhibit 2.4 to the Company's Current Report on Form 8-K filed on January 3, 2000, File No. 1-3473).
2.7	— Purchase Agreement dated as of December 17, 1999 among the Company, Tesoro Gas Resources Company, Inc. and EEX Operating LLC (Membership Interests in Tesoro Southeast LLC) (incorporated by reference herein to Exhibit 2.5 to the Company's Current Report on Form 8-K filed on January 3, 2000, File No. 1-3473).

Exhibit Number	Description of Exhibit
2.8	— Stock Purchase Agreement, dated as of November 19, 1999, by and between the Company and BG International Limited (incorporated by reference herein to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on January 13, 2000, File No. 1-3473).
2.9	— Asset Purchase Agreement, dated July 16, 2001, by and among the Company, BP Corporation North America Inc. and Amoco Oil Company (incorporated by reference herein to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on September 21, 2001, File No. 1-3473).
2.10	— Asset Purchase Agreement, dated July 16, 2001, by and among the Company, BP Corporation North America Inc. and Amoco Oil Company (incorporated by reference herein to Exhibit 2.2 to the Company's Current Report on Form 8-K filed on September 21, 2001, File No. 1-3473).
2.11	— Asset Purchase Agreement, dated July 16, 2001, by and among the Company, BP Corporation North America Inc. and BP Pipelines (North America) Inc. (incorporated by reference herein to Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2001, File No. 1-3473).
2.12	— Sale and Purchase Agreement for Golden Eagle Refining and Marketing Assets, dated February 4, 2002, by and among Ultramar Inc. and Tesoro Refining and Marketing Company, including First Amendment dated February 20, 2002 and related Purchaser Parent Guaranty dated February 4, 2002, and Second Amendment dated May 3, 2002 (incorporated by reference herein to Exhibit 2.12 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001, File No. 1-3473, and Exhibit 2.1 to the Company's Current Report on Form 8-K filed on May 9, 2002, File No. 1-3473).
3.1	— Restated Certificate of Incorporation of the Company (incorporated by reference herein to Exhibit 3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1993, File No. 1-3473).
3.2	— By-Laws of the Company, as amended through June 6, 1996 (incorporated by reference herein to Exhibit 3.2 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1996, File No. 1-3473).
3.3	— Amendment to Restated Certificate of Incorporation of the Company adding a new Article IX limiting Directors' Liability (incorporated by reference herein to Exhibit 3(b) to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1993, File No. 1-3473).
3.4	— Certificate of Designation Establishing a Series A Participating Preferred Stock, dated as of December 16, 1985 (incorporated by reference herein to Exhibit 3(d) to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1993, File No. 1-3473).
3.5	— Certificate of Amendment, dated as of February 9, 1994, to Restated Certificate of Incorporation of the Company amending Article IV, Article V, Article VII and Article VIII (incorporated by reference herein to Exhibit 3(e) to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1993, File No. 1-3473).
3.6	— Certificate of Amendment, dated as of August 3, 1998, to Certificate of Incorporation of the Company, amending Article IV, increasing the number of authorized shares of Common Stock from 50,000,000 to 100,000,000 (incorporated by reference herein to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the period ended September 30, 1998, File No. 1-3473).
4.1	— Form of Coastwide Energy Services Inc. 8% Convertible Subordinated Debenture (incorporated by reference herein to Exhibit 4.3 to Post-Effective Amendment No. 1 to Registration No. 333-00229).
4.2	— Debenture Assumption and Conversion Agreement dated as of February 20, 1996, between the Company, Coastwide Energy Services, Inc. and CNRG Acquisition Corp. (incorporated by reference herein to Exhibit 4.4 to Post-Effective Amendment No. 1 to Registration No. 333-00229).
4.3	— Indenture, dated as of July 2, 1998, between Tesoro Petroleum Corporation and U.S. Bank Trust National Association, as Trustee (incorporated by reference herein to Exhibit 4.4 to Registration Statement No. 333-59871).

Exhibit Number	Description of Exhibit
4.4	— Form of 9% Senior Subordinated Notes due 2008 and 9% Senior Subordinated Notes due 2008, Series B (incorporated by reference herein to Exhibit 4.5 to Registration Statement No. 333-59871).
4.5	— Indenture, dated as of November 6, 2001, between Tesoro Petroleum Corporation and U.S. Bank Trust National Association, as Trustee (incorporated by reference herein to Exhibit 4.8 to Registration Statement No. 333-75056).
4.6	— Form of 9⅝% Senior Subordinated Notes due 2008 and 9⅝% Senior Subordinated Notes due 2008, Series B (incorporated by reference herein to Exhibit 4.7 to Registration Statement No. 333-92468).
4.7	— Indenture, dated as of April 9, 2002, between Tesoro Escrow Corp. and U.S. Bank National Association, as Trustee (incorporated by reference herein to Exhibit 4.9 to Registration Statement No. 333-84018).
4.8	— Supplemental Indenture, dated as of May 17, 2002, among Tesoro Escrow Corp., Tesoro Petroleum Corporation, the subsidiary guarantors and U.S. Bank National Association, as Trustee (incorporated by reference herein to Exhibit 4.10 to Registration Statement No. 333-92468).
4.9	— Form of 9⅝% Senior Subordinated Notes due 2012 (incorporated by reference herein to Exhibit 4.10 to Registration Statement No. 333-84018).
10.1	— $1,275,000,000 Amended and Restated Credit Agreement, dated as of May 17, 2002, among the Company and Lehman Brothers Inc. (arranger), Lehman Commercial Paper Inc. (the syndication agent), Bank One, NA (the administrative agent) and a syndicate of banks, financial institutions and other entities (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on May 24, 2002, File No. 1-3473).
10.2	— Guarantee and Collateral Agreement, dated as of September 6, 2001, made by Tesoro Petroleum Corporation in favor of Bank One, NA, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Amendment No. 2 to the Company's Current Report on Form 8-K filed on November 5, 2001, File No. 1-3473).
10.3	— First Amendment, effective as of September 30, 2002, among Lehman Brothers Inc. (as arranger), Lehman Commercial Paper Inc. (as syndication agent), Bank One, NA (as administrative agent), ABN Amro Bank N.V., Bank of America, N.A., Credit Lyonnais New York and The Bank of Nova Scotia (as co-documentation agents) and a syndicate of banks, financial institutions and other entities, to $1,275,000,000 Amended and Restated Credit Agreement, dated as of May 17, 2002, among the Company and Lehman Brothers Inc. (as arranger), Lehman Commercial Paper Inc. (as the syndication agent), Bank One, NA (as administrative agent), ABN Amro Bank N.V., Credit Lyonnais New York Branch and The Bank of Nova Scotia (as co-documentation agents) and a syndication of banks, financial institutions and other entities (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 25, 2002, File No. 1-3473).
10.4	— Second Amendment dated December 13, 2002, among Tesoro and Lehman Brothers Inc. (as arranger), Lehman Commercial Paper Inc. (as syndication agent), Bank One, NA (as administrative agent), ABN Amro Bank N.V., Credit Lyonnais New York Branch and The Bank of Nova Scotia (as co-documentation agents) and a syndicate of banks, financial institutions other entities, to $1,275,000,000 Amended and Restated Credit Agreement, dated as of May 17, 2002, among Tesoro and Lehman Brothers Inc. (as arranger), Lehman Commercial Paper Inc. (as syndication agent), Bank One, NA (as administrative agent), ABN Amro Bank N.V., Credit Lyonnais New York Branch and The Bank of Nova Scotia (as co-documentation agents) and a syndicate of banks, financial institutions and other entities (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 6, 2003, File No. 1-3473).
10.5	— $100 million Promissory Note, dated as of May 17, 2002, payable by the Company to Ultramar Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 24, 2002, File No. 1-3473).

Exhibit Number	Description of Exhibit
10.6	— $50 million Promissory Note, dated as of May 17, 2002, payable by the Company to Ultramar Inc. (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on May 24, 2002, File No. 1-3473).
†10.7	— The Company's Amended Executive Security Plan, as amended through November 13, 1989, and Funded Executive Security Plan, as amended through February 28, 1990, for executive officers and key personnel (incorporated by reference herein to Exhibit 10(f) to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 1990, File No. 1-3473).
†10.8	— Sixth Amendment to the Company's Amended Executive Security Plan and Seventh Amendment to the Company's Funded Executive Security Plan, both dated effective March 6, 1991 (incorporated by reference herein to Exhibit 10(g) to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 1991, File No. 1-3473).
†10.9	— Seventh Amendment to the Company's Amended Executive Security Plan and Eighth Amendment to the Company's Funded Executive Security Plan, both dated effective December 8, 1994 (incorporated by reference herein to Exhibit 10(f) to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1994, File No. 1-3473).
†10.10	— Eighth Amendment to the Company's Amended Executive Security Plan and Ninth Amendment to the Company's Funded Executive Security Plan, both dated effective June 6, 1996 (incorporated by reference herein to Exhibit 10.5 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No. 1-3473).
†10.11	— Ninth Amendment to the Company's Amended Executive Security Plan and Tenth Amendment to the Company's Funded Executive Security Plan, both dated effective October 1, 1998 (incorporated by reference herein to Exhibit 10.6 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No. 1-3473).
†10.12	— Amended and Restated Employment Agreement between the Company and Bruce A. Smith dated November 1, 1997 (incorporated by reference therein to Exhibit 10.4 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1997, File No. 1-3473).
†10.13	— First Amendment dated October 28, 1998 to Amended and Restated Employment Agreement between the Company and Bruce A. Smith dated November 1, 1997 (incorporated by reference herein to Exhibit 10.8 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No. 1-3473).
†10.14	— Amended and Restated Employment Agreement between the Company and William T. Van Kleef dated as of October 28, 1998 (incorporated by reference herein to Exhibit 10.9 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No. 1-3473).
†10.15	— Amended and Restated Employment Agreement between the Company and James C. Reed, Jr. dated as of October 28, 1998 (incorporated by reference herein to Exhibit 10.10 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No. 1-3473).
*†10.16	— Management Stability Agreement between the Company and Thomas E. Reardon dated November 6, 2002.
†10.17	— Management Stability Agreement between the Company and Faye W. Kurren dated March 15, 2000 (incorporated by reference herein to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2000, File No. 1-3473).
†10.18	— Management Stability Agreement between the Company and Donald A. Nyberg dated December 12, 1996 (incorporated by reference herein to Exhibit 10.7 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1997, File No. 1-3473).
*†10.19	— Management Stability Agreement between the Company and Susan A. Lerette dated November 6, 2002.
*†10.20	— Management Stability Agreement between the Company and Stephen L. Wormington dated November 6, 2002.
*†10.21	— Management Stability Agreement between the Company and Gregory A. Wright dated November 6, 2002.

Exhibit Number	Description of Exhibit
†10.22	— Management Stability Agreement between the Company and Sharon L. Layman dated December 14, 1994 (incorporated by reference herein to Exhibit 10.14 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3473).
*†10.23	— Management Stability Agreement between the Company and W. Eugene Burden dated November 6, 2002.
*†10.24	— Management Stability Agreement between the Company and Everett D. Lewis dated November 6, 2002.
*†10.25	— Management Stability Agreement between the Company and James L. Taylor dated November 6, 2002.
†10.26	— Management Stability Agreement between the Company and Daniel J. Porter dated September 6, 2001 (incorporated by reference herein to Exhibit 10.25 to Registration Statement No. 333-75056).
†10.27	— Management Stability Agreement between the Company and Rick D. Weyen dated September 6, 2001 (incorporated by reference herein to Exhibit 10.26 to Registration Statement No. 333-75056).
*†10.28	— Management Stability Agreement between the Company and Otto C. Schwethelm dated November 6, 2002.
*†10.29	— Management Stability Agreement between the Company and Rodney S. Cason dated November 6, 2002.
*†10.30	— Management Stability Agreement between the Company and Joseph M. Monroe dated November 6, 2002.
*†10.31	— Management Stability Agreement between the Company and Alan R. Anderson dated November 6, 2002.
*†10.32	— Management Stability Agreement between the Company and J. William Haywood dated November 6, 2002.
†10.33	— Management Stability Agreement between the Company and G. Scott Spendlove dated January 24, 2002 (incorporated by reference herein to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002, File No. 1-3473.)
†10.34	— The Company's Amended Incentive Stock Plan of 1982, as amended through February 24, 1988 (incorporated by reference herein to Exhibit 10(t) to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 1988, File No. 1-3473).
†10.35	— Resolution approved by the Company's stockholders on April 30, 1992 extending the term of the Company's Amended Incentive Stock Plan of 1982 to February 24, 1994 (incorporated by reference herein to Exhibit 10(o) to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1992, File No. 1-3473).
†10.36	— Copy of the Company's Key Employee Stock Option Plan dated November 12, 1999 (incorporated by reference herein to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002, File No. 1-3473.)
†10.37	— Copy of the Company's Amended and Restated Executive Long-Term Incentive Plan, as amended through May 25, 2000 (incorporated by reference herein to Exhibit 99.1 to the Company's Registration Statement No. 333-39070 filed on Form S-8).
†10.38	— Amendment to the Company's Amended and Restated Executive Long-Term Incentive Plan effective as of June 20, 2002 (incorporated by reference herein to Exhibit 10.31 to the Company's Registration Statement No. 333-92468).
†10.39	— Copy of the Company's Non-Employee Director Retirement Plan dated December 8, 1994 (incorporated by reference herein to Exhibit 10(t) to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1994, File No. 1-3473).
†10.40	— Amended and Restated 1995 Non-Employee Director Stock Option Plan, as amended through March 15, 2000 (incorporated by reference herein to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002, File No. 1-3473.)

Exhibit Number	Description of Exhibit
†10.41	— Amendment to the Company's Amended and Restated 1995 Non-Employee Director Stock Option Plan (incorporated by reference herein to Exhibit 10.40 to the Company's Registration Statement No. 333-92468).
†10.42	— Copy of the Company's Board of Directors Deferred Compensation Plan dated February 23, 1995 (incorporated by reference herein to Exhibit 10(u) to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1994, File No. 1-3473).
†10.43	— Copy of the Company's Board of Directors Deferred Compensation Trust dated February 23, 1995 (incorporated by reference herein to Exhibit 10(v) to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1994, File No. 1-3473).
†10.44	— Copy of the Company's Board of Directors Deferred Phantom Stock Plan (incorporated by reference herein to Exhibit 10 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 1997, File No. 1-3473).
†10.45	— Phantom Stock Option Agreement between the Company and Bruce A. Smith dated effective October 29, 1997 (incorporated by reference herein to Exhibit 10.20 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1997, File No. 1-3473).
10.46	— Form of Indemnification Agreement between the Company and its officers and directors (incorporated by reference herein to Exhibit B to the Company's Proxy Statement for the Annual Meeting of Stockholders held on February 25, 1987, File No. 1-3473).
10.47	— Letter dated May 5, 2002 from the Company to the State of California Department of Justice, Office of Attorney General (incorporated by reference to Exhibit 10.3 to the Company's Current Report on For 8-K filed on May 24, 2002, File No. 1-3473; portions of this document have been omitted pursuant to a request for confidential treatment).
*21.1	— Subsidiaries of the Company.
*23.1	— Consent of Deloitte & Touche LLP.
*99.1	— Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.2	— Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Filed herewith.

† Identifies management contracts or compensatory plans or arrangements required to be filed as an exhibit hereto pursuant to Item 14(c) of Form 10-K.

Schedules not listed above are omitted because of the absence of the conditions under which they are required or because the information required by such omitted schedules is set forth in the financial statements or the notes thereto.

Copies of exhibits filed as part of this Form 10-K may be obtained by stockholders of record at a charge of $0.15 per page, minimum $5.00 each request. Direct inquiries to the Corporate Secretary, Tesoro Petroleum Corporation, 300 Concord Plaza Drive, San Antonio, Texas, 78216-6999.

(b) Reports on Form 8-K

On January 6, 2003, a Current Report on Form 8-K was filed under Item 5, Other Events, reporting that the Company had issued press releases announcing that the Company had (i) entered into a second amendment of its senior secured credit facility, (ii) sold 70 retail stations in northern California, (iii) sold its product pipeline system in North Dakota and Minnesota and (iv) completed a sale/lease-back transaction for 30 company-operated retail stations in Alaska, Hawaii, Idaho and Utah. The amendment to the senior secured credit facility and five Press Releases issued in December 2002 were filed as Exhibits under Item 7 of this Form 8-K. No financial statements were filed with this Current Report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized

TESORO PETROLEUM CORPORATION

By: /s/ BRUCE A. SMITH

Bruce A. Smith
Chairman of the Board of Directors, President and Chief Executive Officer

Dated: March 21, 2003

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ BRUCE A. SMITH Bruce A. Smith	Chairman of the Board of Directors, President and Chief Executive Officer (Principal Executive Officer)	March 21, 2003
/s/ GREGORY A. WRIGHT Gregory A. Wright	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 21, 2003
/s/ OTTO C. SCHWETHELM Otto C. Schwethelm	Vice President and Controller (Principal Accounting Officer)	March 21, 2003
/s/ STEVEN H. GRAPSTEIN Steven H. Grapstein	Lead Director	March 21, 2003
/s/ WILLIAM J. JOHNSON William J. Johnson	Director	March 21, 2003
/s/ A. MAURICE MYERS A. Maurice Myers	Director	March 21, 2003
/s/ DONALD H. SCHMUDE Donald H. Schmude	Director	March 21, 2003
/s/ PATRICK J. WARD Patrick J. Ward	Director	March 21, 2003

CERTIFICATION PURSUANT TO
SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002

I, Bruce A. Smith, certify that:

1. I have reviewed this annual report on Form 10-K of Tesoro Petroleum Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a. Designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b. Evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c. Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a. All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ BRUCE A. SMITH

Bruce A. Smith
Principal Executive Officer

Date: March 21, 2003

CERTIFICATION PURSUANT TO
SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002

I, Gregory A. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of Tesoro Petroleum Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a. Designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b. Evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c. Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a. All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ GREGORY A. WRIGHT

Gregory A. Wright
Principal Financial Officer

Date: March 21, 2003