TRANSMONTAIGNE INC
Form 10-K/A
February 17, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

(Amendment No. 2)

(Mark One)

/X/ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended June 30, 2003

OR

/ / **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period to
Commission File Number 001-11763

TRANSMONTAIGNE INC.

Delaware	**06-1052062**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Suite 3100, 1670 Broadway
Denver, Colorado 80202
(Address, including zip code, of principal executive offices)

(303) 626-8200
(Telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock; $.01 par value	American Stock Exchange

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

Title of Each Class	Name of Each Exchange on Which Registered

NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such report), and (2) has been subject to such filing requirements for the past 90 days. Yes /X/ 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 Exchange Act Rule 12b-2) Yes /X/ No / /

The aggregate market value of the voting stock held by non-affiliates of the Registrant was $162,810,570. The aggregate market value was computed by reference to the last sale price ($5.95 per share) of the Registrant's Common Stock on the American Stock Exchange on August 29, 2003.

The number of shares of the registrant's Common Stock outstanding on August 29, 2003 was 40,675,530.

DOCUMENTS INCORPORATED BY REFERENCE

None.

EXPLANATORY NOTE

This Amendment No. 2 on Form 10-K/A (the "Amendment") amends TransMontaigne Inc.'s Annual Report on Form 10-K for the year ended June 30, 2003, filed by TransMontaigne (the "Company," "we" or "us") on September 29, 2003 ("Original Form 10-K"), as amended by Amendment No. 1 on Form 10-K/A filed on October 27, 2003. We are filing this Amendment to amend in their entirety the following sections of the Original Form 10-K: "Item 1 Business;" "Item 2 Properties;" "Item 6 Selected Financial Data;" "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations;" "Item 7A Quantitative and Qualitative Disclosures about Market Risk;" "Item 8 Financial Statements and Supplementary Data;" and "Item 15 Exhibits, Financial Statement Schedules and Reports on Form 8-K."

For the reader's ease of reference, we also are providing Items 3, 4, 5, 9 and 9A in this Amendment, although these sections have not been modified from the versions that were included in the Original Form 10-K.

In addition, in connection with the filing of this Amendment and pursuant to Rules 12b-15 and 13a-14(a) under the Securities Exchange Act of 1934, we are including with this Amendment certain currently dated certifications. Except as described above, no other amendments are being made to the Annual Report on Form 10-K filed on September 29, 2003, as amended by Amendment No. 1 on Form 10-K/A filed on October 27, 2003.

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Part I

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report contains certain forward-looking statements and information relating to TransMontaigne Inc., including the following:

i. certain statements, including possible or assumed future results of operations, in "Management's Discussion and Analysis of Financial Condition and Results of Operations;"

ii. any statements contained herein or therein regarding the prospects for our business or any of our services;

iii.

any statements preceded by, followed by or that include the words "may," "seeks," "believes," "expects," "anticipates," "intends," "continues," "estimates," "plans," "targets," "predicts," "attempts," "is scheduled," or similar expressions; and

iv. other statements contained herein or therein regarding matters that are not historical facts.

Our business and results of operations are subject to risks and uncertainties, many of which are beyond our ability to control or predict. Because of these risks and uncertainties, actual results may differ materially from those expressed or implied by forward-looking statements, and investors are cautioned not to place undue reliance on such statements, which speak only as of the date thereof.

The following risk factors, discussed in more detail under the heading "Risk Factors" in our Current Report on Form 8-K filed on May 14, 2003, are important factors that could cause actual results to differ materially from our expectations and may adversely affect our business and results of operations, include, but are not limited to:

> volumes of refined petroleum products shipped in our pipelines and throughput or stored in our terminal facilities;

> the availability of adequate supplies of and demand for petroleum products in the areas in which we operate;

> the effect of any inability to attract customers for our supply management service business;

> continued creditworthiness of, and performance by, contract counterparties;

> the effects of competition;

> our ability to renew customer contracts;

> operational hazards;

> availability and cost of insurance on our assets and operations;

> the success of our risk management activities;

> the effect of changes in commodity prices on our liquidity;

> the impact of any failure of our information technology systems;

> the impact of petroleum product price fluctuations;

> the availability of acquisition opportunities;

> successful integration and future performance of acquired assets;

>

the threat of terrorist attacks or war;

> the impact of current and future laws and governmental regulations;

> liability for environmental claims; and

> the impact of the departure of any key officers.

In addition, other factors such as the following also could cause actual results to differ materially from our expectations:

> general economic, market or business conditions; and

> force majeure and acts of God.

We do not intend to update these forward-looking statements except as required by law.

ITEM 1. BUSINESS

The Company

TransMontaigne Inc., formed in 1995, is a refined petroleum products distribution and supply company based in Denver, Colorado with operations in the United States, primarily in the Gulf Coast, Midwest and East Coast regions. We provide integrated terminal, transportation, storage, supply, distribution and marketing services to refiners, wholesalers, distributors, marketers, and industrial and commercial end-users of refined petroleum products. Our principal activities consist of (i) terminal, pipeline and tug and barge operations, (ii) supply, distribution and marketing and (iii) supply management services.

We predominantly handle refined petroleum products, with the balance being fertilizer, chemicals and other commercial liquids. The refined petroleum products we handle include gasoline, diesel fuel, heating oil, jet fuel and kerosene. Our recent acquisition of terminals and related tug and barge operations in Florida from El Paso Corporation, expanded our product and service offering to include the sale of bunker fuel, used to power ocean vessels, and No. 6 oil, for powering electricity generating plants, as well as the storage of jet fuel, crude oil and asphalt.

We have assembled an asset infrastructure and developed a shipping history on common carrier pipelines which are focused on the distribution of refined petroleum products from the Gulf Coast region to the Midwest and East Coast regions.

We own and operate terminal infrastructure that handles refined petroleum products and other commercial liquids with transportation connections by pipelines, tankers, barges, rail cars and trucks to our facilities or to third-party facilities. At our terminals, we provide throughput, storage, injection and distribution related services to distributors, marketers, retail gasoline station operators and industrial and commercial end-users of refined petroleum products and other commercial liquids. At June 30, 2003, we owned and operated 55 terminals with an aggregate capacity of approximately 21.0 million barrels.

In our supply, distribution and marketing operations, we purchase refined petroleum products primarily from refineries along the Gulf Coasts of Texas and Louisiana and schedule them for delivery to our terminals, as well as terminals owned by third parties, in the Gulf Coast, Midwest and East Coast regions of the United States. We then sell our products primarily through rack sales, bulk sales, and contract sales to cruise ship operators, commercial and industrial end-users, independent retailers, distributors, marketers, government entities and other wholesalers of refined petroleum products.

We also provide supply management services to industrial, commercial and governmental customers that have large ground vehicle fleets. We often combine these services with price management solutions to provide our customers an assured source of fuel at a predictable price. Our ground fleet customers include waste disposal firms, retail consumer products companies, freight and delivery service providers, cable and communication companies, car rental firms, and city and state government agencies.

TransMontaigne Inc. is a holding company that conducts it operations through four primary subsidiaries: TransMontaigne Product Services Inc., which owns the majority of our terminaling and pipeline facilities and conducts the majority of our supply, distribution and marketing operations; Coastal Fuels Marketing, Inc., which owns the Florida marine terminals and conducts supply, distribution and marketing operations principally to marine vessels and power generation plants; Coastal Tug and Barge, Inc., which owns and operates our fleet of tugboats and barges and provides transportation services; and TransMontaigne Transport Inc., which operates our turbo prop aircraft to transport our personnel among locations.

Industry Overview

Product description

Refineries produce refined petroleum products by processing crude oil. Refined petroleum products generally are classified in two groups, "light oils" and "heavy oils." Light oils include gasoline and distillates, such as diesel fuel, heating oil, jet fuel and kerosene. Heavy oils include No. 6 oil and asphalt. The crude oil refining process results in a slate of petroleum products that are all produced simultaneously. When produced at the refinery, refined products of a specific grade, such as unleaded gasoline, are substantially identical in composition from one refinery to the next and are referred to as being "fungible."

Regional production and consumption

The continental United States refined petroleum products market is divided in two distinct regions: the Western United States, which is primarily served by refineries located in the Pacific Coast region; and the Gulf Coast, Midwest and East Coast markets, which are primarily served by refineries located in the Gulf Coast region and imports of refined petroleum products from South America and Europe. Substantially all of TransMontaigne's supply, marketing and distribution operations occur in the Gulf Coast, Midwest and East Coast regions.

The U.S. Department of Energy divides the United States into five geographic regions. These regions are referred to as Petroleum Administration Defense Districts or PADDs. PADD III, which is the Gulf Coast region of the United States, is the largest petroleum refining hub in the U.S. with 55 refineries, responsible for approximately 47% of total U.S. daily refining capacity. The Gulf Coast historically has had an excess supply of refined petroleum products, which are shipped mainly to the East Coast and the Midwest. For the twelve-month period ended December 31, 2002, the Gulf Coast had average refined petroleum production of approximately 7.8 million barrels per day and average refined petroleum product consumption of approximately 3.7 million barrels per day. From 1992 to 2002, the amount of refined petroleum products shipped from the Gulf Coast region increased by approximately 20%, to approximately 4.2 million barrels per day. For the twelve-month period ended June 30, 2003, we purchased and scheduled for transportation out of the Gulf Coast approximately 216,000 barrels per day of refined petroleum products through pipelines and an additional 39,000 barrels per day of refined petroleum products by waterborne vessels.

PADD II, which is the Midwest region, is the second largest PADD in terms of crude oil throughput capacity. Production of petroleum product by refiners located in the Midwest region historically has been less than the demand for such product within that region, resulting in product being supplied from surrounding regions, primarily from the Gulf Coast via common carrier pipelines including the Explorer, TEPPCO, Seaway, Phillips and Centennial pipelines. Supply also is available via barge transport up the Mississippi River with significant deliveries into local markets along the Ohio River. For the twelve-month period ended December 31, 2002, the Midwest region had average refined petroleum production of approximately 3.4 million barrels per day and average refined petroleum product consumption of approximately 4.6 million barrels per day.

PADD I is the East Coast region, and includes the Southeast, Mid-Atlantic and Northeast regions. Production of petroleum product by refiners located in the East Coast region historically has been less than the demand for such product within that region, resulting in product being supplied from surrounding regions, primarily from the Gulf Coast via the Colonial and Plantation pipelines, via barge

and tanker and also imported from foreign producers directly into East Coast ports. For the twelve-month period ended December 31, 2002, the East Coast region had average refined petroleum production of approximately 1.9 million barrels per day and average refined petroleum product consumption of approximately 5.7 million barrels per day.

We believe that our geographically diverse terminal infrastructure and our significant shipping history position us to take advantage of the supply and demand imbalances among the Gulf Coast, Midwest and East Coast regions.

Refining and distribution

Refining. Refineries in the Gulf Coast region, which are owned predominantly by major oil companies, refine crude oil into products that have fungible characteristics, such as sulfur content, octane level, Reid-vapor pressure, and chemical characteristics. The refined products initially are stored at the refineries' own terminal facilities. The refineries owned by major oil companies then schedule for delivery some of their product output to satisfy their own retail delivery obligations, at branded gasoline stations, for example, and sell the remainder of their product output to independent marketing and distribution companies, such as TransMontaigne, for resale. The major refineries typically prefer to sell their excess product to independent marketing and distribution companies rather than to other refineries, which are their primary competitors.

Transportation. For an independent marketing and distribution company to transport product to its terminals, it must schedule its product, at least five to eight days in advance, for shipment on common carrier pipelines. Common carrier pipelines are pipelines with published tariff rates that are regulated by the Federal Energy Regulatory Commission. These pipelines ship product in batches, with each batch consisting of fungible product owned by several different companies. Once in the pipeline, a product may take up to twenty plus days to move from the Gulf Coast to the New York market, with much of the product in the batch being delivered to terminals located along the routes of the common carrier pipelines. A batch of one product, gasoline for example will then be followed by a batch of different product, such as diesel fuel. Because the refineries produce all of the various types of refined products simultaneously, and because the demand for various product types must be met on a continuous basis, product shipments through the common carrier pipelines must be alternated in batches.

During periods of high demand for a particular product, companies may seek to schedule more product than the volume of the batch, in which case the common carrier pipelines will allocate volume based on the shipping history of each company seeking to ship in that batch. Companies that consistently ship significant amounts of product on common carrier pipelines are allocated space on these regulated pipelines for future shipments. Companies without significant shipping histories are not guaranteed similar space on the pipelines and have more difficulty shipping their product to various locations around the country when there is high demand for pipeline capacity to those locations. TransMontaigne has a significant shipping history on the Colonial, Plantation, Explorer and TEPPCO pipelines that allows us to ship product through these pipelines during periods of high demand for pipeline capacity.

As a batch of co-mingled product is shipped on a pipeline, each terminal along the way draws the volume of fungible product that is scheduled for that facility as the batch passes in the pipeline. Consequently, each terminal must monitor the type of product in the common carrier pipeline at any time to determine when to draw product scheduled for delivery to that terminal. In addition, both the common carrier pipeline and the terminal monitor the volume of product drawn to ensure that the precise amount scheduled for delivery at that location is actually received.

With respect to product that is shipped to marine terminals, specific volumes of product are loaded into tankers or barges at the ports connected to major refinery complexes and shipped to a marine terminal.

At both inland and marine terminals, the various refined petroleum products are stored in tanks. While each type of product continues to be fungible, different products must be segregated by tank. For example, because the characteristics of gasoline are required to be changed at least twice per year in many locations to meet government regulations, regular unleaded gasoline produced for winter cannot be stored in a tank together with regular unleaded gasoline produced for summer. Our 55 terminal facilities include over 720 tanks ranging in capacity from 1,000 to 300,000 barrels per tank.

Delivery. Each inland terminal has a tanker truck loading facility referred to as a "rack." Often, commercial and industrial end-users and independent retailers will rely on independent trucking companies to pick up product at the rack and transport it to the end-user or retailer at its location. A truck scheduled to pick up product at a terminal will drive up to a rack. The driver will swipe a magnetic card that identifies the customer purchasing the product, the carrier and the driver as well as the products to be pumped into the truck. Each truck holds an aggregate of approximately 8,000 gallons of various products in different compartments. Our computerized system also electronically reviews the credentials of the carrier, including insurance and certain mandated certifications, the credit of the customer and confirms the customer is within scheduled allocation limits. When all conditions are verified as being current and correct, the system authorizes the delivery of the product to the truck. As product is being loaded into the truck, additives are added into certain products, including all gasoline, to conform to government specifications and individual customer requirements. If a truck is loading gasoline for retail sale by an independent gasoline station, generic additives will be added to the gasoline as it is loaded into the truck. If the gasoline is for delivery to a branded retail gasoline station, the proprietary additive compound of that particular retailer will be added to the gasoline as it is loaded. The type and amount of additive are electronically and mechanically controlled by equipment located at the truck loading rack.

At marine terminals, the product will be stored in tanks and may be delivered to tanker trucks over a rack in the same manner as at an inland terminal. Product also may be delivered to cruise ships and other vessels, known as "bunkering," either at the dock, through a pipeline or truck, or by barge. Cruise ships typically require approximately 8,000 barrels, the equivalent of 42 truckloads, of product

per refueling. Bunker fuel is a mixture of diesel fuel and No. 6 oil. Each large vessel essentially requires its own mixture of bunker fuel to match the distinct characteristics of that ship's engines. Because the mixture for each ship requires precision to mix and deliver, cruise ships often prefer to refuel in United States ports with experienced companies.

Our Operations

Terminals, pipelines, and tugs and barges

The refined petroleum product distribution system in the United States links refineries to end-users of gasoline and other refined petroleum products through a network of terminals, pipelines, tankers, barges, rail cars and trucks. Terminals play a key role in the delivery of product to wholesalers, retailers and end-users by providing storage, distribution, blending, injection and other ancillary services. The two basic types of terminals are inland terminals, which are supplied by pipelines, rail cars and trucks, and marine terminals, which are supplied by ships and barges.

We own and operate terminal infrastructure of 55 terminals with approximately 21.0 million barrels of aggregate capacity that handles refined petroleum products and other commercial liquids. At our terminals, we provide throughput, storage, injection and other distribution related services to wholesalers, distributors, marketers, retail gasoline station operators and industrial and commercial end-users of refined petroleum products and other commercial liquids. We currently own and operate the following terminal facilities:

> 31 terminals with approximately 9.2 million barrels of capacity, located at various points along the Plantation and Colonial pipeline corridor, which extends from the Gulf Coast through the Southeast, Mid-Atlantic and Northeast regions;

> 15 terminals with approximately 3.5 million barrels of capacity, located in the Midwest and upper and lower Mississippi River areas;

> 8 terminals with approximately 6.0 million barrels of capacity, at various locations in Florida; and

> 1 terminal complex in Brownsville, Texas with approximately 2.2 million barrels of capacity.

Our network of terminals is geographically diverse with our largest terminal, the Brownsville complex, accounting for approximately 10% of our total capacity. Brownsville is uniquely situated in that its size and scope of operations enable it to handle a large majority of liquid products movements in the geographic area between Mexico and south Texas. Fee based revenue generating activities include storage tank rentals, truck scale operations, additive injection, steam generation and handling, direct transfer operations and product blending activities. In Florida, we own and operate nine tugboats and 13 barges and a proprietary pipeline in Port Everglades, which we use to transport our product to cruise ships and other marine vessels for refueling. We also use our tugs and barges to transport third party product from our storage tanks to their facilities and to relocate our product among our Florida terminals when needed to augment our capacity.

We use our tank capacity at our Florida terminals to blend diesel fuel and No. 6 oil into bunker fuel meeting our customers' specifications. In addition, we use our diesel fuel and No. 6 oil hydrant pipelines at Port Everglades to blend these products at dockside for direct delivery into our customers' vessels.

Along the Mississippi River we own and operate a dock facility in Baton Rouge, Louisiana that is interconnected to the Colonial Pipeline. This connection provides the ability to load product originating from the Colonial Pipeline onto barges for distribution up the Mississippi River, as well as

serves as an injection point into the Colonial Pipeline for product unloaded from barges transporting it down the Mississippi River.

We own, operate and currently are the sole shipper on an interstate refined petroleum products pipeline operating from Mt. Vernon, Missouri to Rogers, Arkansas known as the Razorback Pipeline, together with associated terminal facilities at Mt. Vernon and Rogers. The Rogers terminal, together with the Mt. Vernon terminal and Razorback Pipeline, allows us flexibility to ship product from the Gulf Coast to this Midwest market via its connection to the Explorer Pipeline. We also own and operate a small intrastate crude oil gathering pipeline system, located in east Texas known as the CETEX Pipeline.

We generate revenues in our terminal, pipeline and tug and barge operations from throughput fees, storage fees, additization fees, transportation fees, ship-assist fees and fees from other ancillary services.

Throughput Revenues. We earn throughput fees for each barrel of refined petroleum product that is distributed at our terminals through our supply and marketing efforts, through exchange agreements, or for third parties. A significant majority of the throughput at our terminals consists of product that we have purchased, marketed, sold and dispensed over the rack at our terminals. The remainder of the throughput volume at our terminals is generated from exchange agreements and throughput arrangements with third parties. Terminal throughput fees are based on the volume of products distributed at the facility's truck loading racks, generally at a standard rate per barrel of product. Unlike common-carrier pipeline services, terminal services are not subject to price (tariff) regulations, allowing the marketplace to determine the prices that are charged for services. With respect to fungible products, we enter into throughput agreements with customers who provide product to our terminal and agree to draw co-mingled product from that terminal at a later date. These customers prefer to take delivery of co-mingled product from us at our terminals and pay a throughput fee with respect to that product rather than leasing storage capacity.

For example, our supply, distribution and marketing business may purchase a specific volume of product in the Gulf Coast and enter into a sale agreement for the product in Washington, D.C. The product may be shipped to our terminals serving that area for delivery to the customer or the delivery obligation may be satisfied from our existing inventory in those terminals. In either event, the delivery of product from our terminal constitutes throughput. Third-party throughput operates in the same manner except that it is a third party that directs the product delivery to our terminals rather than our own supply, distribution and marketing business.

Exchange agreements generally are fixed term agreements that involve our receipt of a specified volume of product at one location in exchange for delivery by us of product at a different location. We enter into exchange agreements with major oil companies to increase throughput at our terminals and establish greater shipping history on the common carrier pipelines. We generally receive a fee based on the volume of the product exchanged. The exchange fee takes into account the terminal throughput fee, the cost of transportation from the receipt location to the delivery location, as well as a fee for "regrading" if we deliver one type of product and receive a different type of product. For example, if a major oil company has a one-year agreement to deliver premium gasoline in Atlanta, but does not have a terminal there, that company may enter into an exchange agreement with us whereby we will provide the product at our truck rack in Atlanta and, in exchange, they will provide us with product, which may be the same or a different grade of gasoline, in the Gulf Coast and pay us a negotiated fee.

Storage Revenues. We lease storage capacity at our terminals to third parties and earn a storage fee based on the volume of the storage capacity leased. Terminal storage fees generally are based on a per

barrel of leased capacity per month rate and will vary with the duration of the storage arrangement, the type of product stored and special handling requirements, particularly when certain types of chemicals and other commercial liquids are involved. For example, the entire 2.2 million barrel capacity at our Brownsville terminal facility is leased, or available for lease, to third parties.

Additization Revenues. Additization or injection is the process of injecting refined petroleum products with additives and dyes. Some injected products, such as detergent additives, are standard and are required to comply with governmental regulations, while other injected products are proprietary to certain of our customers. We provide injection services to our customers in connection with the delivery of product at our terminals. These fees are generally based on the volume of product injected and delivered over the rack at our terminals.

Pipeline Revenues. We earn pipeline transportation fees at our Razorback and CETEX pipelines based on the volume of product transported and the distance from the origin point to the delivery point. Tariff rates on the Razorback Pipeline are regulated by FERC. Transportation fees for the CETEX Pipeline are not regulated by FERC and are based on negotiated rates.

Barge and Ship-Assist Revenues. Our barges earn transportation fees from third parties at negotiated rates based on the volume of product that is shipped and the distance to the delivery point. Our barges also provide marine vessel fueling services, referred to as bunkering, at our Port Everglades/Ft. Lauderdale, Cape Canaveral, Port Manatee/Tampa and Fisher Island/Miami terminals. Bunkering fees are based on the volume and type of product sold. Our tugboats also earn fees for providing docking and other ship-assist services to cruise and cargo ships and other vessels in South Florida ports based on a per docking per tug basis.

Other Service Revenues. In addition to providing storage and distribution services at our terminal facilities, we also provide ancillary services including heating and mixing of stored products and product transfer services. Many heavy oil products, such as No. 6 oil, bunker fuel and asphalt require heating to keep them in a liquid state suitable for shipping. For example, heavy oil products may be transported to a terminal in non-insulated tank rail cars and, therefore, must be re-heated before being transferred into terminal storage tanks or into trucks or barges. We provide these heating services to our customers and charge negotiated fees based on the type and volume of product heated. We also earn transfer fees for transferring product between tanks and transportation equipment. For example, we would charge a fee to transfer product from a rail car or a barge to a storage tank at a customer's request. We also recognize revenues upon the sale of product to our supply, distribution, and marketing operation resulting from the excess of product deposited by third parties into our terminals over the amount of product that the customer is contractually permitted to withdraw from those terminals.

Supply, distribution and marketing

We generally purchase our inventory of refined petroleum products at prevailing prices from refiners and producers at production points and common trading locations along the Gulf Coasts of Texas and Louisiana. Once we purchase these products, we schedule them for delivery via pipelines and barges to our terminals, as well as terminals owned by third parties with which we have storage or throughput agreements, in the Midwest and East Coast regions. From these terminal locations, we then sell our products to customers primarily through three types of arrangements: rack sales, bulk sales and contract sales.

Rack Sales. Rack sales are spot sales that do not involve continuing contractual obligations to purchase or deliver product. Rack sales are priced and delivered on a daily basis through truck loading

racks or marine fueling equipment. At the end of each day for each of our terminals, we establish the selling price for each product for each of our delivery locations. We announce or "post" to independent local jobbers via facsimile, website, e-mail, and telephone communications the rack sale price of various products for the following morning. Typical rack sale purchasers include commercial and industrial end-users, independent retailers and small, independent marketers, referred to as "jobbers," who resell product to retail gasoline stations or other end-users. Our selling price of a particular product on a particular day is a function of our supply at that delivery location or terminal, our estimate of the costs to replenish the product at that delivery location, our desire to reduce inventory levels at that particular location that day and other factors.

We manage the physical quantity of our inventories of product through rack sales. Our rack sales volume for a particular product is sensitive to changes in price. If our objective is to increase rack sales volume for a particular product of ours at a specific delivery location, then we would post the selling price of that product at the low end of the range of competitive prices being offered in the applicable market to induce purchasers in that market to choose to buy our product as opposed to product offered by competitors in that market. This would occur if, for example, we expect that prices for that product will decrease at that location in the near future or if we have significant deliveries scheduled to arrive at that location in the near term.

Bulk Sales. Bulk sales generally involve the sale of products in large quantities in the major cash markets including the Houston Gulf Coast, New York Harbor, Chicago, Illinois and the Tulsa, Oklahoma refining area. We also may make a bulk sale of products while the product is being transported in the common carrier pipelines or by barge or vessel. Finally, we may make a bulk sale to purchasers while our product is in the Gulf Coast prior to the time when this product enters the common carrier pipelines.

Supply disruptions, extreme weather, and other unforeseen factors may cause supply and demand imbalances in major cash markets around the country resulting in price differences, referred to as "basis differentials," between these markets. These price differences often exceed the costs of transporting product between the markets. Bulk sales of products are entered into with major oil companies and independent wholesalers and distributors who purchase product in the market to cover their delivery obligations during such periods of supply and demand imbalance. We capitalize on these variations by monitoring prices in the major cash markets, re-scheduling shipments and making bulk sales of product in the markets that achieve the highest value to us.

For example, a major oil company may become aware that it is going to have a production outage at its refinery in the Gulf Coast region and may determine that the outage will cause several of its terminals in the Northeast to be short of product within a few days. If the major oil company cannot replace the product, it could fail to meet delivery obligations from the affected terminals and, therefore, must turn to the market to supply its needs. In that case, if we had the required type and volume of product available, either located in a terminal or in-transit along a pipeline, we may enter into a bulk sales agreement to sell the product to the major oil company in exchange for cash.

Contract Sales. Contract sales are made pursuant to negotiated contracts, generally ranging from one to six months in duration, that we enter into with cruise ship operators, local market wholesalers, independent gasoline station chains, heating oil suppliers and other customers. Contract sales provide these customers with a specified volume of product during the agreement term. Delivery of product sold under these arrangements generally is at our truck racks or via our marine fueling equipment. At the customer's option, the pricing of the product delivered under a contract sale may be fixed at a stipulated price per gallon, or it may vary based on changes in published indices.

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For example, we may enter into an agreement with a retail heating oil supplier in the Northeast to provide the supplier with heating oil, for delivery at our truck rack or a rack owned by a third party, during the high demand winter months at a fixed price.

Supply management services

Industrial, commercial and governmental entities with significant ground fleets need to ensure adequate fuel supplies for their fleet vehicles. For many of these companies and governmental entities, the cost of fuel is a significant expenditure and the administration and record keeping involved is burdensome. Some companies also maintain their own proprietary refueling facilities, which requires monitoring fuel levels, scheduling deliveries, controlling inventories and filing excise tax returns. Other companies use retail gasoline stations to refuel their vehicles, resulting in extensive payment handling as well as exposure to price differences among stations and price fluctuations in the market. In addition, companies that enter into their own risk management contracts to mitigate the effects of fuel price volatility are subject to complex accounting for such transactions that can be avoided by entering into sales agreements with third party providers of price management services. In response to these market needs, we developed our supply management services business segment. We provide supply management services to companies and governmental entities that desire to outsource their fuel supply function to focus their efforts on their core competencies and to reduce the price volatility associated with their fuel supplies for budgetary reasons. These services often include price management solutions that provide our customers an assured source of fuel at a predictable price. Our fleet customers include, among others, PepsiCo, Sysco Corporation, FedEx Corporation, Waste Management, Inc., Allied Waste Industries, Waste Connections, Inc., the Indiana Department of Transportation, and the City of Raleigh, North Carolina.

These customers use our proprietary web-based technology, which provides them the ability to budget their fuel costs while outsourcing all or a portion of their procurement, scheduling, routing, excise tax and payment processes. Using electronic metering equipment, we can monitor the amounts of product stored and delivered at our customers' proprietary refueling locations. In addition, through our strategic relationship with Comdata-Comchek MasterCard, we can monitor the volume of fuel purchased by our customers' ground fleet vehicles at retail truck stops and service stations.

We currently offer three types of supply management services: delivered fuel price management, retail price management and logistical supply management services.

Delivered Fuel Price Management. Delivered fuel price management contracts involve the sales of committed quantities of specific motor fuels delivered to our customer's proprietary fleet refueling locations, at fixed prices for terms up to three years. On a daily basis, for each of our customer's facilities, we procure product, schedule delivery, manage local inventory quantities and summarize each customer's purchases by location and vehicle. Typical customers for delivered fuel price management services have large fleets of vehicles that drive fixed, scheduled routes, making refueling at a proprietary refueling location an attractive choice.

For example, we may enter into a delivered fuel price management contract with a customer that has storage and refueling facilities at its fleet operations centers. We will agree to deliver diesel fuel directly to the customer's proprietary refueling location at a fixed price per gallon. We then monitor the customer's fuel usage and schedule additional fuel deliveries as needed. We will provide the customer with a single invoice for all of the fuel deliveries that includes reconciliation of all bills of lading against deliveries and breaks out accumulated third-party transportation costs. This information is available to the customer on a customized web-based portal.

Retail Price Management. Retail price management contracts typically are entered into for a period of up to 18 months with customers that require flexibility in refueling locations, either because they do not have proprietary refueling facilities or because they generally do not operate along fixed routes. Under these arrangements, customers commit to a specific monthly notional quantity of product within one or more metropolitan areas. The customer's drivers will purchase fuel at a retail gasoline station within the metropolitan area and use their Comdata-Comchek MasterCard to pay the retail price at that station. We then settle with our customer the net financial difference between a stipulated retail price index for that metropolitan area and our customer's contract price on a monthly basis. If the contract price is less than the average indexed price, we will pay the customer the net difference. If the contract price exceeds the average indexed price, the customer will pay us the net difference. In either case, the customer will have effectively managed its exposure to fuel costs at the contract price. Through our proprietary web-based software, our customers receive a monthly report of each of these activities. Typical customers for retail price management services include companies that have large fleets that are dispatched to specific service or delivery locations on an as-needed basis.

For example, we may enter into a retail price management contract with a customer for a price per gallon of gasoline equal to a stipulated retail price index plus a negotiated fee. The customer's fleet drivers are able to purchase fuel at almost any retail gasoline station using their Comdata-Comchek MasterCard. At the time of purchase, the driver pays for the gasoline using the company fleet card, and the vehicle number and the amount and price of fuel purchased are recorded. Comdata-Comchek MasterCard sends daily electronic reports to us indicating a summary of the data collected by the credit cards. This information is made available to the customer on our proprietary web-site. We then settle the net difference between the indexed price and the customer's contract price on a monthly basis.

Logistical Supply Management. Under our logistical supply management arrangements, we provide our proprietary web-based refined petroleum product procurement, inventory management, scheduling, routing, excise tax and consolidated billing services to customers on a stand alone basis without any delivery or price management products. These services also are often integrated with our Comdata-Comchek MasterCard relationship, thereby affording our customers complete flexibility to obtain their supply of products at almost any retail gasoline station. These services typically are charged to the customer on a per gallon basis or at negotiated rates. Typical logistical service customers include governments and customers that are seeking to outsource or streamline record keeping functions but are willing to continue to bear price fluctuations. Often, a customer will initially contract for logistical supply management services and later use our delivered fuel price management or retail price management services.

For example, a customer may want the benefits of a single invoice for all fuel purchases and the ability to manage its fuel usage on-line. We provide access to fuel purchase data in real time, providing an automated platform for analysis tailored to each customer. In addition, many customers have diverse logistical requirements, buying fuel in bulk, at retail locations and through mobile refueling services. We can provide integrated management of all supply and logistical requirements for our customers' bulk locations and use our Comdata-Comchek MasterCard relationship to manage the retail and mobile refueling volumes. The company fleet card would capture the fueling transaction data for the bulk, retail and mobile refueling activity facilitating customized reporting on our proprietary web site. Our customers benefit from a single resource for the procurement, pricing and reporting of all fuel data regardless of the logistical requirements.

We have received a revenue ruling from the Internal Revenue Service that allows us to provide state and local government vehicle fleets with a simplified process for managing and obtaining fuel tax exemptions. State and local governments are exempt from paying federal excise taxes on the fuel consumed by their vehicle fleets. Normally, fleet vehicles would purchase gasoline at retail gasoline stations, where excise taxes are included in the price of gasoline, and the government agency would file a return to obtain a refund of excise taxes paid. By using our supply management services, these tax-exempt government fleets can purchase fuel at almost any retail location using their Comdata-Comchek MasterCard. Comdata pays the merchant and transfers the balance to our account. We then bill our customer net of federal excise taxes. We file all necessary excise tax returns on behalf of these customers with the applicable taxing authorities and we receive a credit against our other excise tax payment obligations. We believe that this additional service gives us a competitive advantage that will allow us to attract additional government fleet customers.

Recent Acquisitions

Coastal Fuels assets

On February 28, 2003, we acquired the Coastal Fuels assets, including five Florida terminals, with aggregate storage capacity of approximately 4.9 million barrels, and a related tug and barge operation. The purchase price for the transaction was approximately $156 million, including approximately $37 million of inventory.

The Coastal Fuels assets primarily provide sales and storage of bunker fuel, No. 6 oil, diesel fuel and gasoline at Cape Canaveral, Port Manatee/Tampa, Port Everglades/Ft. Lauderdale and Fisher Island/Miami, and storage of asphalt at Jacksonville, Florida. In addition, the Coastal Fuels assets facilities provide a variety of third-party lease capacity to the asphalt, jet fuel, power generation and crude oil industries.

With the addition of the Coastal Fuels assets, we have significantly expanded our existing Florida operations at our Port Everglades and Tampa terminals. In addition, the acquisition of the Coastal Fuels assets provide the following benefits:

> we have established a leading presence in key bunkering locations in various Florida ports, including the Ports of Miami, Port Everglades, Cape Canaveral and Tampa;

> the ports served are among the top cruise ship ports in the U.S., providing steady year-round demand with greater demand in the winter months;

> the terminals are located primarily in areas with limited opportunity for new terminal expansion because of zoning, land values and environmental considerations;

> no refineries exist in Florida and the major Florida markets are served by waterborne vessels due to the absence of major product supply pipelines;

> Florida is one of the fastest growing states in population, with additional potential demand growth in both the cruise ship bunkering and light oil businesses;

> the Coastal Fuels assets include the only pipeline hydrant delivery system serving Port Everglades, which allows a more efficient refueling process than barge to ship refueling; and

> a number of opportunities to increase operational efficiency exist with our current operations in Florida.

Fairfax, Virginia terminal

On January 31, 2003, we acquired a 500,000 barrel terminal in Fairfax, Virginia, which extended our supply, distribution and marketing presence in the Mid-Atlantic market. The Fairfax terminal supplies petroleum products to the Washington D.C. market and receives product off the Colonial Pipeline. The strategic reasons for acquiring the Fairfax terminal included:

- the attractive geographic location of the terminal:
  - the terminal expands our delivery capabilities into and around Washington, D.C.;
  - the terminal is located in an area with limited opportunity for new terminal expansion because of zoning, land values and environmental considerations; and
  - the Washington, D.C. area is growing and provides future growth opportunities.
- potential synergies that would result with our existing terminal infrastructure along the Colonial Pipeline.

Norfolk, Virginia terminal

On October 1, 2003, we closed on the purchase of a 900,000 barrel terminal in Norfolk, Virginia, which increased our supply, distribution and marketing presence in the Mid-Atlantic market. The strategic reasons for acquiring the Norfolk terminal included:

- an opportunity to realize operating synergies by combining these operations with our existing Norfolk, Virginia terminal;
- the acquired terminal provides us with additional storage in the market; and
- the terminal has a docking facility that will permit us to receive shipments from and deliver shipments to the water.

Risk management

Our risk management committee, composed of senior executives of TransMontaigne, has established risk management policies to monitor and manage price risks. Our risk management strategy generally is intended to maintain a balanced position of forward sale and forward purchase commitments, discretionary inventories held for immediate sale or exchange and risk management contracts, thereby reducing exposure to commodity price fluctuations. We evaluate our exposure to commodity price risk from an overall portfolio basis that considers the continuous movement of discretionary inventory volumes held for immediate sale or exchange and our obligations to deliver products at fixed prices through our sales contracts and supply management contracts. Our physical inventory position, which includes firm commitments to buy and sell product, is reconciled daily through the use of our inventory monitoring equipment and software and that net position is offset with risk management contracts, principally futures contracts on the NYMEX. Futures contracts are obligations to purchase or sell a specific volume of product at a fixed price at a future date.

We purchase product primarily from refineries along the Gulf Coast in Texas and Louisiana. To the extent that we have physical inventory or purchase commitments without corresponding agreements to sell the product for physical delivery to third parties, we enter into a futures contract on the NYMEX to sell product at a specified future date and, thereby, reduce our exposure to changes in commodity prices. Upon sale of the physical inventory of product to a third party, we enter into a futures contract that offsets all or a portion of the original futures contract and, effectively, cancels our original NYMEX position to the extent of the product sold. If there is correlation in price changes between the forward price curve in the futures market and the value of physical products in the cash market, the net losses on our risk management activities should be offset by the net operating margins we receive when we sell the underlying discretionary inventory. Therefore, in order to effectively manage commodity price risk, we must predict when we will sell the underlying product. If we fail to accurately predict the timing of those future sales, and the product remains in our inventory longer than the expiration date of the futures contract, we must settle the old futures contract and enter into a new futures contract to sell the product to manage the commodity price risk against the same inventory. We refer to this as "rolling" the risk management contracts. Furthermore, we may be unable to precisely match the underlying product in our futures contracts with the exact type of product in our physical inventory. To the extent that price fluctuations of the product covered by the NYMEX futures contract does not match the price fluctuations of the product in our physical inventory, our exposure may not be mitigated.

We also manage our exposure to commodity price risks in our supply management services business. At the execution of each contract for which we provide price management solutions, we either purchase an appropriate supply of motor fuel or we enter into NYMEX futures contracts in volumes equal to the customer's contractual commitment to purchase product to mitigate our exposure to commodity price fluctuations throughout the contract period. However, with respect to a portion of our contracts, we are unable to precisely match the underlying product in our risk management contract to the exact type of product contemplated by our sales contract, delivered fuel price management contract or retail price management contract. To the extent that the price fluctuations of the product covered in our sales contracts do not match the price fluctuations of the product covered by the NYMEX futures contract that we use, our exposure may not be entirely mitigated.

There are certain risks that we either do not attempt to manage or that cannot be completely managed. For example, we generally do not manage the price risk relating to basis differentials. We attempt to capitalize on basis differentials by transporting product to the delivery location that maximizes the value of the product to us. These basis differentials create opportunities for increased operating margins when we successfully exploit the highest value location for sales of our discretionary inventories of products. However, the margins created from exploiting these market inefficiencies do not occur evenly or predictably from period to period and may cause fluctuations in our results of operations.

Our existing operations require us to maintain base operating inventory volumes of approximately 2.9 million barrels, consisting primarily of product in transit on common carrier pipelines. We also maintain product linefill and tank bottom volumes of approximately 0.9 million barrels in our terminals and pipelines. Our base operating inventory volumes and product linefill and tank bottom volumes are collectively referred to by us as our minimum volumes. We generally do not manage the commodity price risk relating to minimum volumes because these volumes generally are not available for immediate sale or exchange. As a result, any futures contracts used to manage the commodity price risk relating to the minimum volumes would have to be continuously rolled from period to period, which, during unfavorable market conditions, would result in a realized loss on the futures contract without the realization of an offsetting gain in the value of the base operating inventory. Changes in our operation, such as the acquisition of additional terminals, may result in changes to our minimum volumes.

Our risk management policy, however, allows our management team the discretion under certain market conditions to manage the commodity price risk relating to up to 500,000 barrels of our base operating inventory, which would reduce the unmanaged inventory to approximately 3.3 million barrels, or to leave unmanaged up to 500,000 barrels of our discretionary inventory available for immediate sale or exchange, which would increase our unmanaged inventory to approximately 4.3 million barrels. Management is allowed this discretion in order to create the opportunity to capture financial gains, or prevent financial losses, on predictable price movements with respect to up to 500,000 barrels of physical product. We decide whether to manage the commodity price risk

relating to a portion of our base operating inventory or to leave a portion of our discretionary inventory available for immediate sale or exchange unmanaged depending on our expectations of future market changes. To the extent that we do not manage the commodity price risk relating to a portion of our inventory and commodity prices move adversely, we could suffer losses on that inventory. If, however, prices move favorably, we would realize a gain on the sale of the inventory that we would not realize if substantially all of our inventory was managed.

All of our futures contracts are traded on the NYMEX and, therefore, require daily settlements for changes in commodity prices. Unfavorable commodity price changes subject us to margin calls that require us to provide cash collateral to the NYMEX in amounts that may be material. For example, we may enter into a futures contract to manage the commodity price risk relating to discretionary inventory held for immediate sale or exchange. If commodity prices rise before the expiration date of the futures contract, it will be "out of the money," which means that we will be obligated to deposit funds to cover a margin call based on the increase in the commodity price. If commodity prices fall before the expiration date of the futures contract, a portion of our margin call deposits with the NYMEX will be returned to us. If there is correlation in pricing and timing between the futures market and the physical products market, the net changes in our margin position should be offset by the net operating margins we receive when we sell the underlying discretionary inventory. We use our credit lines to fund these margin calls, but such funding requirements could exceed our ability to access capital. If we are unable to meet these margin calls with borrowings or cash on hand, we would be forced to sell product to meet the margin calls or to unwind futures contracts. If we are forced to sell product to meet margin calls, we may have to sell at prices or in locations that are not advantageous, and could incur financial losses as a result.

Industry Trends

Petroleum imports and Gulf Coast production

United States crude oil production has declined from 7.2 million barrels per day in 1992 to 5.7 million barrels per day in 2002. Imports of petroleum from the Middle East, South America and elsewhere have increased substantially over this period from 7.9 million barrels per day in 1992 to 11.5 million barrels per day in 2002. Domestic crude oil production may be refined at any of the regional refineries around the United States. However, the imported crude oil generally is shipped by vessel into the Gulf Coast for processing at the large refining complexes. Crude oil production in the Gulf of Mexico, one of the largest sources of domestic production, also is refined primarily in these Gulf Coast refineries. The refined petroleum products then are shipped to other regions of the United States. We believe that this trend will lead to more refined petroleum product shipment from the Gulf Coast to the Midwest and East Coast, requiring additional transportation and storage capacity in the Midwest and East Coast.

New sulfur regulations

In February 2002, the Environmental Protection Agency, or EPA, promulgated the Tier 2 Motor Vehicle Emissions Standards Final Rule for all passenger vehicles, establishing standards for sulfur content in gasoline. These regulations mandate that the average sulfur content of gasoline for highway use produced at any refinery not exceed 30 parts per million during any calendar year by January 1, 2006. In addition, in January 2001, the EPA promulgated its on-road diesel regulations, which will require a 97% reduction in the sulfur content of diesel fuel sold for highway use by June 1, 2006. Regulations for off-road diesel equipment also are pending. The stricter regulations will require refining companies to make significant capital expenditures to upgrade their facilities to comply with the new standards. Because of the technical sophistication and the capital outlays that will be required

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for compliance with such regulations, the large oil companies with major refining operations in the Gulf Coast are expected to be better prepared to meet the new standards than the smaller independent refiners. The large oil companies also may choose to partially refine crude oil in the larger and better-equipped Gulf Coast refineries for the purpose of reducing its sulfur content, and then ship the partially refined product to their smaller and less technically sophisticated inland refineries for final processing. We believe that these trends will lead to more refined petroleum product shipment from the Gulf Coast to the Midwest and East Coast, requiring additional transportation and storage capacity in the Midwest and East Coast.

Consolidation and specialization

In the 1990's, the petroleum industry entered a period of consolidation and specialization.

> Refiners and marketers began to pursue development of large-scale, cost-efficient operations, thus leading to several refinery acquisitions, alliances and joint ventures. The companies involved in several of the mergers of large oil companies have sold retail and terminal assets in order to rationalize merged operations, and to comply with legal requirements to divest assets in certain geographic markets.

> Major oil companies also began to re-deploy their resources to focus on their core competencies of exploration and production, refining and retail marketing. Industry participants have sought to sell portions of their proprietary transportation and storage and distribution networks.

This industry trend towards consolidation and specialization has created opportunities to capitalize on storage and distribution services. We expect that acquisition opportunities will continue to be generated as this trend continues.

The growth in Gulf Coast refining capacity has resulted in part from consolidation in the petroleum industry to take advantage of economies of scale from operating larger, concentrated refineries. The growth in refining capacity and increased product flow attributable to the Gulf Coast region has created a need for additional transportation, storage and distribution facilities in the Gulf Coast, Midwest and East Coast regions. The competition among refiners resulting from the consolidation trend, combined with continued environmental pressures, governmental regulations and market conditions, increasingly is resulting in the closing of smaller, independent inland refiners, creating even greater demand for petroleum products refined by the major oil companies in the Gulf Coast region.

Hypermarkets and alternative retail gasoline outlets

The retail distribution of gasoline is experiencing a transformation as consumer consumption patterns are moving away from gasoline distributed at the retail outlets of large oil companies, or "branded gasoline," toward unbranded gasoline from independent retail outlets offering lower prices and convenient locations. For example, many hypermarkets, grocery stores, convenience stores, discount retailers and wholesale outlets have installed gasoline pumps in their parking lots as a way to expand their product and service offerings and to allow their customers the benefit of "one-stop shopping." The increase in popularity of unbranded outlets has created new sales and distribution opportunities for independent petroleum product suppliers.

Competitive Strengths

We believe that we have the following competitive strengths, which allow us to take advantage of the industry trends outlined above:

Significant asset base and shipping history

The Gulf Coast is a large shipper of refined petroleum products to the Midwest and East Coast regions. We have a geographically diverse network of terminals that allows us to take advantage of the differences between supply in the Gulf Coast and demand in the Midwest and East Coast. Our size, both in terms of number of terminals and total storage capacity, compares favorably with any integrated oil company. Regionally, in the Southeast region and in Florida, we have the largest amount of aggregate terminal storage capacity.

This geographic diversity also allows us to quickly sell our product inventory from time to time in one or more locations while maximizing value to us. To purchase products in the Gulf Coast and sell the products in the Midwest and East Coast, it is necessary to have a shipping history on common carrier pipelines and an extensive network of terminals. Our shipping history on the Colonial, Plantation, Explorer and TEPPCO pipelines allows us to ship large volumes of products over these pipelines to our and third-party terminals. This shipping history provides us the benefit of allocated space on these common carrier pipelines during high demand periods, which is an advantage over competitors that do not have as significant a shipping history when pipeline capacity is over-subscribed.

We believe that we will be able to further capitalize on our network of terminals in the Gulf Coast, Midwest and East Coast following implementation of the new sulfur standards promulgated by the EPA. We anticipate that refining companies will be required to make significant capital expenditures to upgrade facilities to comply with such new sulfur regulations. Because of the technical sophistication and the capital outlays that will be required for compliance with such regulations, we expect that the large oil companies with major refining operations in the Gulf Coast will gain a competitive advantage over the smaller independent refiners. We believe that this will lead to more petroleum product shipment from the Gulf Coast to the Midwest and the East Coast, and require additional storage capacity in the Midwest and East Coast, providing additional growth opportunities for us.

Ability to link asset base, product supply and management services

Our supply, distribution and marketing operations and our terminal, pipeline and tug and barge operations each utilize and benefit from each other, creating opportunities to realize additional value in each of our business segments that could not be realized if each business segment were operated independently.

Our supply, distribution and marketing operations generally use our terminal, tug and barge and pipeline infrastructure to market various products and provide specialized supply, logistical and risk management services to our customers. A significant portion of the throughput on our terminal and pipeline infrastructure is driven by our own supply, distribution and marketing business. As a result, we do not rely solely on third parties for our throughput activity.

We own and operate terminals located throughout the regions served by four major petroleum product pipelines on which we have a significant shipping history. In addition, we own and operate a petroleum product pipeline and a fleet tugboats and barges. Also, we own and operate a dock strategically located on the Mississippi River with an interconnection to the Colonial Pipeline. We also have substantial experience in managing complex petroleum product supply and demand arrangements, utilizing equipment and software, that allow us to monitor supplies in all of our facilities on a daily basis.

Because we link our asset base with our supply, distribution and marketing operations, we have the flexibility to market product during adverse market conditions to meet our contractual volume obligations, maintain our common carrier pipeline shipping history and generate throughput revenues.

Our geographically diverse terminal infrastructure allows our supply, distribution and marketing operations to pursue product purchase and sale opportunities across various regions in transactions that maximize value to us. For example, if we have product in the Colonial Pipeline, which serves the Mid-Atlantic and the Northeast, but there is a supply disruption in Chicago, we can take advantage of our Baton Rouge dock facility to redirect the product by drawing it off the Colonial Pipeline and loading it on barges for shipment to the Chicago area to take advantage of the basis differential. We then quickly evaluate whether the redirection of this shipment will result in shortages at any of our other terminals along the Colonial Pipeline and, if so, reduce demand at those terminals by posting a higher rack sales price. In addition, we can purchase additional product in the Gulf Coast region and take advantage of our extensive shipping history to be allocated pipeline capacity to increase subsequent shipments on the Colonial Pipeline to make up any shortfall caused by the original redirection of product to Chicago.

Supply management services

In order to operate more efficiently and to reduce overhead costs, many companies and governmental entities have begun to outsource their fuel supply function. This trend is creating an emerging market for services that allow these customers to focus their efforts on their core competencies and to reduce the price volatility associated with fuel supply for budgetary reasons. We provide a broad scope of services that include fuel supply, monitoring, excise tax administration and price management solutions, allowing our customers to obtain all of the required fuel supply management functions from a single source. We believe that we are the only significant independent fuel supply management services provider in the United States offering this extensive suite of services.

Technology and back-office infrastructure

We have assembled monitoring equipment and software to create an integrated, flexible system that allows us to effectively manage petroleum products throughout our terminal, pipeline and water-borne infrastructure on a real time basis.

All of our terminals are equipped with equipment to monitor product supplies and outflows as well as for any environmentally harmful releases of product, such as leaks or spills. This equipment is interconnected electronically with our central inventory management office and automatically reports supply levels in all of our facilities several times daily. The electronic linkage of our terminals with our product supply function creates an inherent competitive strength by allowing us to make real time decisions on product purchases and sales.

We use a magnetic card system at our terminals that allows us to control product sales deliveries and also allows us to manage our credit risk exposure. Each of our rack customers is given a magnetic card that can be used only at our terminals. Upon arrival at one of our racks, the driver of the truck swipes the magnetic card and inputs a product and volume request. This information is processed through our computerized inventory management system to determine the credentials of the carrier and whether the driver's product and volume request is within the customer's allocation of product for that month. The system also determines if the customer is current in its payments to us. If it is determined that the customer's allocation of product already has been drawn or if the customer is delinquent in paying its invoices to us, then the sale will not be allowed. The magnetic card system at each terminal is interconnected with our inventory management and billing system.

We also use a proprietary web-based system in our supply management services business that allows us to provide refined petroleum product procurement, inventory management, scheduling, routing and excise tax and consolidated billing services to our customers. Through our relationship with Comdata-Comchek MasterCard, we provide integrated billing services to our supply management services customers. These customers receive MasterCard credit cards that are distributed to their fleet vehicle operators for use in purchasing gasoline at any retail gasoline station that accepts MasterCard as a method of payment. On a daily basis, we receive information on these accounts electronically from Comdata-Comchek MasterCard into our billing system. This information is posted on our web-based system which can be accessed by our supply management services customers, allowing them to closely monitor fuel usage and costs by vehicle on a real time basis.

The refined petroleum products that arrive at terminals do not have excise taxes included in their price. At the time the products are sold over the rack, however, excise tax must be added to the price and paid by the purchasers of our products. The process of calculating, collecting, paying and reporting the excise taxes imposed by state and federal authorities requires extensive knowledge, expertise and administrative infrastructure. For example, we may make a delivery of gasoline at our rack that is located in one state to a truck that will transport the fuel to a neighboring state. Because taxation rules differ among locations, we must keep track of where the fuel will be ultimately delivered, charge the appropriate excise tax and file excise tax returns in the appropriate jurisdictions. We have developed an infrastructure to administer excise taxes on product that is handled at our terminals.

We also have substantial experience in managing complex petroleum product supply and demand arrangements. Our back office and technology infrastructure has been established through significant time and capital commitments and gives us an advantage over competitors.

Strong management team

Our executive management team has extensive industry experience and several members of the team have worked together for over 20 years. Several members of executive management were instrumental in building Associated Natural Gas Corporation, a natural gas gathering, processing and marketing company, into a company with an enterprise value of over $800 million at the time of its 1994 sale to Panhandle Eastern Corporation.

Strategies

The goal of our business strategies is to enhance our position as a leading independent provider of integrated refined petroleum products terminal, storage, supply, distribution and marketing services. Our strategies include:

> Capitalize on the acquisition of the Coastal Fuels assets in Florida.

We intend to take advantage of the steady year-round demand in the ports served.

We intend to pursue growth opportunities in both the cruise ship bunkering and light oil businesses.

We intend to expand our bunkering service to shipping markets outside of the cruise ship industry.

> Capitalize on our infrastructure by linking our significant asset base to our supply, distribution and marketing business.

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We intend to take advantage of our extensive network of terminals, as well as our shipping history on common carrier pipelines, to exploit supply and demand variations and basis differentials among the Gulf Coast, Midwest and East Coast regions.

We intend to use our significant terminal capacity to meet the growing demand for boutique blends of gasoline spurred by recent and anticipated changes in government regulations.

We intend to capitalize on the favorable location of our Baton Rouge docking facility, which allows us to transfer product between the Colonial Pipeline which serves the East Coast, and the Mississippi River, which serves portions of the Midwest. This allows us to redirect product to the Midwest or the East Coast to take advantage of basis differentials.

We intend to capitalize on the favorable location of, and significant capacity at, our Brownsville terminal complex. The Brownsville terminal complex is the primary provider for its area. A pipeline is scheduled for completion in 2003 that will carry product between Mexico and the United States and will terminate at the Brownsville terminal complex.

> Pursue Attractive Acquisitions.

We intend to acquire additional terminal and storage facilities that will either complement our existing asset base and distribution capabilities, or provide entry into new markets. In light of the recent industry trend large energy companies divesting their distribution and terminal operations, we believe there will continue to be significant acquisition opportunities.

> Actively pursue new sales and distribution opportunities by marketing our services to hypermarkets.

> Expand our supply management services.

We intend to expand our existing supply management team and equipment to enable us to provide supply management services to additional customers with large ground transportation fleets.

We intend to actively market our supply management solution for managing and obtaining excise tax exemptions on fuel purchases to government fleet customers.

> Continue to manage our exposure to commodity price volatility.

Our risk management strategy allows us to continue to have product throughput at our terminals regardless of commodity price volatility, permitting us to buy, market and sell product and services even during adverse commodity market conditions.

Our risk management strategy also allows us to keep our efforts focused on maximizing the value of our physical assets and expanding our supply management services business.

Environmental Matters

Our operations are subject to extensive federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, and which require expenditures for remediation at various operating facilities, as well as expenditures in connection with the construction of new facilities. We believe that our operations and facilities are in material compliance with applicable environmental regulations. Environmental laws and regulations have changed substantially and rapidly over the last 20 years, and we anticipate that there will be continuing changes in the future. The trend in environmental regulation is to place more restrictions and limitations on activities that may impact the environment, such as emissions of pollutants, generation and disposal of wastes and use and handling of chemical substances. Increasingly strict

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environmental restrictions and limitations have resulted in increased operating costs for us and other businesses throughout the United States, and the costs of compliance with environmental laws and regulations may continue to increase. We will attempt to anticipate future regulatory requirements that might be imposed and to plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We do not anticipate that we will be required in the near future to expend amounts that are material in relation to our total capital expenditures program to comply with environmental laws and regulations, but inasmuch as such laws and regulations are frequently changed, we are unable to predict the ultimate costs of compliance.

TransMontaigne's operations require environmental permits under various federal, state and local environmental statutes and regulations. The cost involved in obtaining and renewing these permits is not material.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act or CWA, imposes strict controls against the discharge of oil and its derivates into navigable waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial potential liability for the costs of removing an oil or hazardous substance spill. State laws for the control of water pollution also provide for various civil and criminal penalties and liabilities in the event of a release of petroleum or its derivatives in surface waters or into the groundwater. Spill prevention control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum tank spill, rupture or leak. A containment berm is an earthen or cement barrier, impervious to liquids, which surrounds a storage tank holding between 1,000 and

500,000 gallons of petroleum products or other hazardous materials and used to prevent spilling and extensive damage to the environment. The berm is a form of secondary containment with the storage tank itself being the primary instrument of containment.

Contamination resulting from spills or releases of refined petroleum products is an inherent risk in the petroleum terminal and pipeline industry. To the extent that groundwater contamination requiring remediation exists around the assets we own as a result of past operations, we believe any such contamination can be controlled or remedied without having a material adverse effect on our financial condition. However, such costs are often unpredictable and are site specific and, therefore, the effect may be material in the aggregate.

The primary federal law for oil spill liability is the Oil Pollution Act of 1990, or OPA, which addresses three principal areas of oil pollution prevention, containment and cleanup. It applies to vessels, offshore platforms, and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the United States Coast Guard, the United States Department of Transportation Office of Pipeline Safety, or OPS, or the EPA. Numerous states have enacted laws similar to OPA. Under OPA and similar state laws, responsible parties for a regulated facility from which oil is discharged may be liable for removal costs and natural resources damages. We believe that we are in material compliance with regulations pursuant to OPA and similar state laws.

The EPA has adopted regulations that require us to obtain permits to discharge certain storm water run-off. Storm water discharge permits also may be required by certain states in which we operate. Such permits may require us to monitor and sample the effluent from our operations. We believe that we are in material compliance with effluent limitations at our facilities.

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Water permits are required for various types of terminal stormwater discharges. There are no TransMontaigne terminal locations that discharge any type of process wastewater. Such discharges generally fall into two categories: petroleum contact and non-contact. The sources of contact water are the truck loading operations at some of the terminals. Many TransMontaigne terminal locations do not have contact water discharges, and thus no need for discharge permits, by virtue of employment of closed-loop water handling systems. The water generated in these systems is transported offsite and disposed of properly. At locations where contact water is discharged on site, permit conditions dictate control technology requirements, effluent limitations and confirmation sampling. Non-contact stormwater is generated at most terminal locations, primarily from rainfall collection in aboveground storage tank secondary containment enclosures or dikes. Various types of permits regulate these discharges, with most being "General" state-wide industry specific mechanisms. The cost involved in obtaining and renewing these permits is not material.

Air emissions

Our operations are subject to the federal Clean Air Act and comparable state and local statutes. The Clean Air Act Amendments of 1990 require most industrial operations in the United States to incur capital expenditures to meet the air emission control standards that are developed and implemented by the EPA and state environmental agencies. Pursuant to the Clean Air Act, any of our facilities that emit volatile organic compounds or nitrogen oxides and are located in ozone non-attainment areas face increasingly stringent regulations, including requirements to install various levels of control technology on sources of pollutants. Some of our facilities have been included within the categories of hazardous air pollutant sources. The Clean Air Act regulations are still being implemented by the EPA and state agencies. We believe that we are in material compliance with existing standards and regulations pursuant to the Clean Air Act and similar state and local laws, and we do not anticipate that implementation of additional regulations will have a material adverse effect on us.

Air permits are required for TransMontaigne's terminaling operations that result in the emission of regulated air contaminants. These operations in general include fugitive volatile organic compounds (primarily hydrocarbons) from truck loading activities and tank working losses. The sources of these emissions are strictly regulated through the permitting process. Such regulation includes stringent control technology, extensive permit review and periodic renewal. The cost involved in obtaining and renewing these permits is not material.

CERCLA

Other than Coastal Fuels Marketing Inc. ("CFMI"), neither TransMontaigne nor any of its subsidiaries is a named party in any CERCLA related action. CFMI, which is now a wholly owned subsidiary of TransMontaigne, had been named as a PRP in three State of Florida CERCLA actions which originated from waste disposal by third parties at off-site locations prior to TransMontaigne's acquisition of CFMI from El Paso Corporation in 2003. TransMontaigne has been indemnified by El Paso for any costs TransMontaigne may incur for these issues. Due diligence research at the time of the acquisition of CFMI indicated that El Paso would not be likely to incur any future costs related to these actions; a worst-case analysis estimated El Paso's potential exposure at a total of $850,000.

All of TransMontaigne's terminal facilities are classified by the USEPA as Conditionally Exempt Small Quantity Generators and do not generate hazardous waste except on isolated and infrequent cases. At such times, only third party disposal sites which have been audited and approved by TransMontaigne are used.

Tariff Regulations

The Razorback Pipeline, which runs between Mt. Vernon, Missouri and Rogers, Arkansas, is an interstate petroleum products pipeline and is subject to regulation by FERC under the Interstate Commerce Act and the Energy Policy Act of 1992 and rules and orders promulgated under those statutes. FERC regulation requires that interstate oil pipeline rates be posted publicly and that these rates be "just and reasonable" and nondiscriminatory. Rates of interstate oil pipeline companies are currently regulated by FERC primarily through an index methodology, whereby a pipeline is allowed to change its rates based on the change from year to year in the Producer Price Index for finished goods, less 1%. In the alternative, interstate oil pipeline companies may elect to support rate filings by using a cost-of-service methodology, competitive market showings or actual agreements between shippers and the oil pipeline company.

The CETEX Pipeline, our intrastate crude oil pipeline located in east Texas, is subject to regulation by the Texas Railroad Commission. Texas regulations require that intrastate tariffs be filed with the Texas Railroad Commission and allows shippers to challenge such tariffs.

Under current FERC regulations, we are permitted to charge "just and reasonable," non-discriminatory tariffs for the transportation of refined products through the Razorback Pipeline. Given our ability to utilize either posted rates subject to increases tied to the Producer Price Index, to utilize rates tied to cost of service methodology, competitive market showing or actual agreements between shippers and TransMontaigne, we do not believe that these regulations would have any negative material monetary impact on us unless the regulations were substantially modified in such a manner so as to prevent a pipeline transportation company's ability to earn a fair return for the shipment of petroleum products utilizing its transportation system, which we believe to be an unlikely scenario.

Likewise, Texas tariff regulations administered by the Texas Railroad Commission permit transporting pipeline companies to obtain a fair return for utilization of their transportation system, although such tariffs are subject to challenge by shippers should the shipper deem such tariffs to be excessive. Again, unless the Texas Railroad Commission regulations were materially modified so as to prevent a pipeline transportation company from earning a fair and reasonable return for the shipment of crude oil utilizing its transportation system, these regulations would not have a negative material monetary impact on us.

Safety Regulation

We are subject to regulation by the United States Department of Transportation under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act, or HLPSA, and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. HLPSA covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations and also to permit access to and copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that we are in material compliance with these HLPSA regulations.

OPS regulations require qualification of pipeline personnel. These regulations require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error. The regulation establishes qualification requirements for individuals performing covered tasks, and amends certain training

requirements in existing regulations. We believe that we are in material compliance with these OPS regulations.

We also are subject to OPS regulation for High Consequence Areas, or HCAs, for Category 2 pipeline systems (companies operating less than 500 miles of jurisdictional pipeline). This regulation specifies how to assess, evaluate, repair and validate the integrity of pipeline segments that could impact populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways, in the event of a release. Our assets that are subject to these requirements are: (1) the Pinebelt Pipeline (the pipeline connecting the Collins and Purvis, Mississippi complexes); (2) the Razorback Pipeline; (3) the Bellemeade Pipeline (pipeline connecting the Richmond Terminal to the nearby Virginia Power plant); (4) the Birmingham Terminal pipeline connection to Plantation Pipeline; and (5) the Bainbridge Terminal pipeline connection to the nearby SEGCO Power Plant. The regulation requires an integrity management program that utilizes internal pipeline inspection, pressure testing, or other equally effective means to assess the integrity of pipeline segments in HCAs. The program requires periodic review of pipeline segments in HCAs to ensure adequate preventative and mitigative measures exist. Through this program, we evaluated a range of threats to each pipeline segment's integrity by analyzing available information about the pipeline segment and consequences of a failure in a HCA. The regulation requires prompt action to address integrity issues raised by the assessment and analysis. The complete baseline assessment of all segments must be performed by February 17, 2009, with intermediate compliance deadlines prior to that date. We believe that we are in material compliance with the OPS regulation of HCAs.

We are also subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act, and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities, and local citizens upon request. We believe that we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

In general, we expect to increase our expenditures during the next decade to comply with higher industry and regulatory safety standards such as those described above. Although we cannot estimate the magnitude of such expenditures at this time, we do not believe that they will have a material adverse impact on our results of operations.

Other Regulations

We also are subject to the Jones Act and the Merchant Marine Act of 1936 because of our ownership and operation of ocean vessels. Numerous other federal, state and local rules regulate our operations pursuant to which governmental agencies have the ability to suspend, curtail or modify our operations. We believe that we are in material compliance with these regulations.

Operational Hazards and Insurance

Our terminal and pipeline facilities may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties.

The insurance covers all of our assets in amounts that we consider to be reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. The events of September 11, 2001, and their overall effect on the insurance industry have adversely impacted the availability and cost of coverage. Due to these events, insurers have excluded acts of terrorism and sabotage from our insurance policies. On certain of our key assets, we have purchased a separate insurance policy for acts of terrorism and sabotage.

Competition

We face intense competition in our terminal and pipeline operations as well as in our supply and marketing operations. Our competitors include other terminal and pipeline companies, the major integrated oil companies, their marketing affiliates and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours, and control greater supplies of refined petroleum products.

Employees

We had 654 employees at October 26, 2003. No employees are subject to representation by unions for collective bargaining purposes.

Market and Industry Data

Market and industry data and other statistical information used throughout this report are based on independent industry publications by market research firms or other published independent sources. Some data are also based on our good faith estimates, which are derived from our review of internal surveys, as well as the independent sources. Although we believe these sources are reliable, we have not independently verified the information derived from independent sources.

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ITEM 2. PROPERTIES

The locations and approximate shell capacity of our terminals (all of which are owned by us) as of June 30, 2003 are as follows:

Locations	Approximate Shell Capacity (in barrels)	Locations	Approximate Shell Capacity (in barrels)
Colonial/Plantation Facilities:		**Upper River Facilities:**	
Albany, GA	131,000	Evansville, IN	239,000
Americus, GA	31,000	Greater Cincinnati, KY	191,000
Athens, GA	77,000	Henderson, KY	273,000
Atlanta, GA	116,000	New Albany, IN	219,000
Bainbridge, GA	99,000	Louisville, KY	138,000
Belton, SC	130,000	Cape Girardeau, MO	140,000
Belton, SC	297,000	East Liverpool, OH	219,000
Birmingham, AL	370,000	Owensboro, KY	152,000
Charlotte, NC	223,000	Paducah, KY Complex	306,000
Charlotte, NC	324,000	**Total**	**1,877,000**
Collins, MS	138,000		
Collins, MS (Pipeline Injection Facility)	1,470,000	**Lower River Facilities:**	
Doraville, GA	436,000	Baton Rouge, LA Dock facility	
Fairfax, VA	502,000	Arkansas City, AR	773,000
Greensboro, NC	181,000	Greenville, MS Complex	396,000
Greensboro, NC	484,000	**Total**	**1,169,000**
Griffin, GA	51,000		
Lookout Mountain, GA	109,000	**Brownsville Facilities:**	
Macon, GA	100,000	Brownsville, TX Complex	**2,257,000**
Meridian, MS	82,000	**Total**	2,257,000
Montgomery, AL	59,000		
Montvale, VA	489,000	**Florida Facilities:**	
Norfolk, VA	380,000	Pensacola, FL	272,000
Purvis, MS	870,000	Port Everglades, FL	369,000
Purvis, MS	135,000	Tampa, FL	475,000
Rensselaer, NY	530,000	**Total**	**1,116,000**
Richmond, VA	459,000		
Rome, GA	59,000	**Coastal Fuels Terminals:**	

Locations	Approximate Shell Capacity (in barrels)	Locations	Approximate Shell Capacity (in barrels)
Selma, NC	507,000	Jacksonville, FL	385,000
Spartanburg, SC	85,000	Cape Canaveral, FL	708,000
Spartanburg, SC	305,000	Port Everglades, FL	1,650,000
Total	**9,229,000**	Fisher Island, FL	670,000
		Port Manatee/Tampa, FL	1,517,000
Midwest Facilities:		**Total**	**4,930,000**
Mount Vernon, MO	215,000		
Rogers, AR	171,000		
Chippewa Falls, WI	126,000		
Total	**512,000**	**TOTAL CAPACITY**	**21,090,000**

The names, approximate length in miles and geographical locations of our pipelines as of June 30, 2003 are as follows:

Pipeline Name	Approximate Miles of Pipeline	Geographical Location
Razorback	67	Mt. Vernon, Missouri south to Rogers, Arkansas
CETEX	220	East Texas area north of Tyler, Texas

Our executive offices are located at 1670 Broadway, Suite 3100, Denver, CO 80202; telephone number (303) 626-8200 and facsimile number (303) 626-8228. In addition, we have an operations office located at 200 Mansell Court East, Suite 600, Roswell, Georgia 30076; telephone number (770) 518-3500 and facsimile number (770) 518-3567.

ITEM 3. LEGAL PROCEEDINGS

We have been named as a defendant in various lawsuits and a party to various other legal proceedings, in the ordinary course of business, some of which are covered in whole or in part by insurance. We believe that the outcome of such lawsuits and other proceedings will not individually or in the aggregate have a material adverse effect on our consolidated financial condition, results of operations, or cash flows.

ITEM 4. VOTE OF SECURITY HOLDERS

No matter was submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the three months ended June 30, 2003.

Part II

ITEM 5. MARKET FOR COMMON STOCK

Our common stock is traded on the American Stock Exchange under the symbol "TMG". The following table sets forth, for the periods indicated, the range of high and low per share sale prices for our common stock as reported on the American Stock Exchange.

	Low	High
July 1, 2001 through September 30, 2001	$ 4.00	$ 6.75
October 1, 2001 through December 31, 2001	$ 4.35	$ 6.30
January 1, 2002 through March 31, 2002	$ 5.10	$ 6.00
April 1, 2002 through June 30, 2002	$ 4.20	$ 6.05
July 1, 2002 through September 30, 2002	$ 4.50	$ 6.30
October 1, 2002 through December 31, 2002	$ 3.26	$ 4.98
January 1, 2003 through March 31, 2003	$ 3.75	$ 4.85
April 1, 2003 through June 30, 2003	$ 4.02	$ 6.48

On August 29, 2003, the last reported sale price for our common stock on the American Stock Exchange was $5.95 per share. As of August 29, 2002, there were 496 stockholders of record of our common stock. This number does not include stockholders whose shares are held in trust by other entities. The actual number of stockholders is greater than the number of stockholders of record. Based on the number of annual reports requested by brokers, we estimate that we have approximately 2,100 beneficial owners of our common stock as of August 29, 2003.

On June 28, 2002, we issued 72,890 shares of Series B Redeemable Convertible Preferred Stock in a transaction exempt from registration pursuant to Regulation D of the Securities Act of 1933 (see Note 12 of Notes to consolidated financial statements). The offering was made solely to TransMontaigne's existing holders of Series A Preferred Stock, each of whom represented that it was an "accredited investor" as defined by Rule 501 under the Securities Act. The offering was made in accordance with the requirements of Regulation D applicable to an offering of securities under Rule 506.

No dividends were declared or paid on our common stock during the periods reported in the table above. We intend to retain future cash flow for use in our business and have no current intention of paying dividends to our common stockholders in the foreseeable future. Any payment of future dividends to our common stockholders and the amounts thereof will depend upon our earnings, financial condition, capital requirements and other factors deemed relevant by our Board of Directors. Our Working Capital Credit Facility, Senior Subordinated Notes and certificate of designation of our Series B Redeemable Convertible Preferred stock contain restrictions on the payment of dividends on our common stock. Under the terms and conditions of our Working Capital Credit Facility, we are precluded from paying a dividend on our common stock without the express consent of the lenders (see Note 11 of Notes to consolidated financial statements). Our $9^1/_8$% Senior Subordinated Notes due 2010 restrict the payment of cash dividends on our common stock unless we comply with certain financial covenants relating to restricted payments. Our Series B Redeemable Convertible Preferred stock certificate of designation restricts the payment of cash dividends on our common stock unless the holders of our preferred stock have received a cash dividend for their immediately preceding dividend payment date. Additionally, we are precluded from paying dividends on our common stock in excess of $10 million during any 12-month period without the express consent of holders of two-thirds of the then outstanding shares of preferred stock.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data for each of the years in the five-year period ended June 30, 2003 has been derived from our consolidated financial statements. You should not expect the results for any prior periods to be indicative of the results that may be achieved in future periods. You should read the following information together with our historical consolidated financial statements and related notes and with "Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this annual report.

	Years Ended June 30,				
	2003(4)	2002	2001	2000	1999
	(As restated)				
	(dollars in thousands)				
Statement of Operations Data:					
Supply, distribution and marketing:					
Revenues	$ 8,241,001	$ 6,001,170	$ 5,182,492	$ 5,014,752	$ 2,935,550
Less costs of products sold and other direct costs and expenses	(8,190,918)	(5,932,423)	(5,136,174)	(4,995,899)	(2,914,272)
Net operating margin(1)	50,083	68,747	46,318	18,853	21,278
Terminals, pipelines, and tugs and barges:					
Revenues	82,988	63,386	79,707	78,522	56,374
Direct operating costs and expenses	(35,196)	(27,668)	(33,817)	(34,268)	(24,678)
Net operating margin(1)	47,792	35,718	45,890	44,254	31,696
Natural gas services:					
Revenues				18,249	55,137
Direct operating costs and expenses				(7,759)	(43,167)

	Years Ended June 30,				
Net operating margin(1)				10,490	11,970
Total net operating margins(1)	$ 97,875	$ 104,465	$ 92,208	$ 73,597	$ 64,944

Total net operating margins(1)	$ 97,875	$ 104,465	$ 92,208	$ 73,597	$ 64,944
Costs and expenses:					
Selling, general and administrative	(40,491)	(35,211)	(34,072)	(41,680)	(17,990)
Depreciation and amortization	(19,371)	(16,556)	(19,510)	(22,344)	(16,775)
Lower of cost or market write-downs on product linefill and tank bottom volumes	(633)	(12,963)	(18,318)		
Corporate relocation and transition	(1,449)	(6,316)			
Impairment of long-lived assets				(50,136)	
Operating income (loss)	35,931	33,419	20,308	(40,563)	30,179
Interest expense, net	(14,419)	(11,837)	(15,215)	(25,121)	(23,575)
Other expense	(4,902)	(7,546)	(9,235)	(5,350)	(3,210)
Gain (loss) on disposition of assets, net		(13)	22,146	13,930	
Earnings (loss) before income taxes	16,610	14,023	18,004	(57,104)	3,394
Income (taxes) benefit	(8,510)	(5,465)	(6,666)	19,167	(1,455)
Earnings (loss) before cumulative effect of a change in accounting principle	8,100	8,558	11,338	(37,937)	1,939
Cumulative effect adjustment, net of tax benefit	(1,297)				
Net earnings (loss)	6,803	8,558	11,338	(37,937)	1,939
Preferred stock dividends, net	(3,984)	(11,351)	(8,963)	(8,506)	(2,274)
Net earnings (loss) attributable to common stockholders	$ 2,819	$ (2,793)	$ 2,375	$ (46,443)	$ (335)
Earnings (loss) per common share:					
Basic	.07	(.09)	.08	(1.52)	(.01)
Diluted	.07	(.09)	.08	(1.52)	(.01)

	Years Ended June 30,				
	2003(4)	**2002**	**2001**	**2000**	**1999**

	Years Ended June 30,				
	(As restated)				
	(dollars in thousands)				
Other Financial Data:					
Net cash provided (used) by operating activities	$ 33,323	$ (101,512)	$ 51,936	$ 267,526	$ (68,861)
Net cash provided (used) by investing activities	$ (170,625)	$ 102,778	$ (18,969)	$ 77,902	$ (467,040)
Net cash provided (used) by financing activities	$ 134,419	$ 3,811	$ (61,130)	$ (305,417)	$ 522,613
Total debt to total capital	57.0%	39.0%	30.5%	38.4%	57.0%
Ratio of earnings to fixed charges(2)	1.8x	1.6x	1.6x		1.1x

	June 30,				
	2003(4)	2002	2001	2000	1999
	(dollars in thousands)				
Balance Sheet Data:					
Cash and cash equivalents	$ 27,969	$ 30,852	$ 25,775	$ 53,938	$ 13,927
Working capital(3)	$ 63,946	$ 168,092	$ 31,934	$ 134,807	$ 356,602
Total assets	$ 986,069	$ 735,328	$ 712,365	$ 834,572	$ 1,106,009
Total debt	$ 379,534	$ 198,312	$ 150,000	$ 206,995	$ 497,672
Total preferred stock	$ 79,329	$ 105,360	$ 174,825	$ 170,115	$ 170,115
Total common stockholders' equity	$ 210,269	$ 205,350	$ 167,550	$ 161,983	$ 205,936

(1) Net operating margins represents revenues, less cost of product sold and other direct operating costs and expenses.

(2) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of earnings before income taxes plus fixed charges. "Fixed charges" represent interest incurred (whether expensed or capitalized), amortization of deferred financing costs, and that portion of rental expense on operating leases deemed to be the equivalent of interest. We reported a loss for the year ended June 30, 2000 and the earnings for such period were insufficient to cover fixed charges by approximately $57.1 million.

(3) Working capital is defined as current assets less current liabilities.

(4) The consolidated financial statements include the results of operations of the Coastal Fuels assets from the closing date of the transaction (February 28, 2003).

(5) The consolidated statement of operations for the year ended June 30, 2003 has been restated (see Note 1(c) of Notes to consolidated financial statements).

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

The following discussion and analysis of the results of operations and financial condition should be read in conjunction with the accompanying consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

A summary of the significant accounting policies that we have adopted and followed in the preparation of our consolidated financial statements is detailed in Note 1 of Notes to the consolidated financial statements. Certain of these accounting policies require the use of estimates. We have identified the following estimates that, in our opinion, are subjective in nature, require the exercise of judgment, and involve complex analysis. These estimates are based on our knowledge and understanding of current conditions and actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial condition and results of operations.

Allowance for Doubtful Accounts. At June 30, 2003, our allowance for doubtful accounts was approximately $1.9 million. Our allowance for doubtful accounts represents the amount of trade receivables that we do not expect to collect. The valuation of our allowance for doubtful accounts is based on our analysis of specific individual customer balances that are past due and, from that analysis, we estimate the amount of the receivable balance that we do not expect to collect. That estimate is based on various factors, including our experience in collecting past due amounts from the customer being evaluated, the customer's current financial condition, the current economic environment and the economic outlook for the future.

Inventories Discretionary Volumes Held for Immediate Sale or Exchange. At June 30, 2003, we held products for sale or exchange in the ordinary course of business with a cost basis of approximately $130.5 million and a fair value of approximately $136.4 million. At June 30, 2003, our inventories discretionary volumes held for immediate sale or exchange are carried at the lower of cost or market value in the accompanying consolidated balance sheet. For purposes of evaluating the financial performance of our business segments, we reflect our inventories discretionary volumes held for immediate sale or exchange are reflected at market value. The market value of our inventories discretionary volumes held for immediate sale or exchange is based on quoted prices, when available. Our refined petroleum products inventories are traded in large fungible bulk markets (Pasadena, TX, New York Harbor, Chicago, IL, Tulsa, OK refining area, and Los Angeles, CA); and in city-specific wholesale markets. Quoted market prices (e.g., NYMEX, Platt's Bulk, and OPIS Wholesale) are readily available for these markets.

However, quoted prices are not available from brokers for all future periods and delivery locations in which we are committed to do business. When quoted prices are not available, the market value of our inventories discretionary volumes held for immediate sale or exchange is based on the nearest quoted market price, plus quoted basis differentials to the various bulk market areas, plus the transportation cost to deliver the product from the bulk trading market to the city-specific markets. Near-term basis differentials are quoted and traded in the over-the-counter petroleum markets and are verified by the various cash brokers that facilitate trading. We estimate the basis differentials for certain deferred trading months and city-specific locations because we cannot secure a forward traded basis differential quote from a broker. In those situations, our mark-to-market model estimates the basis differentials based on a rolling historical average, which is updated quarterly. We utilize this valuation methodology for all inventories discretionary volumes held for immediate sale or exchange, along with any

valuation of a related exchange imbalance with a trading partner. Currently, it is not practicable for us to estimate the effects on our financial condition, results of operations, or cash flows from an unfavorable change in basis differentials.

Prepaid Transportation Costs. At June 30, 2003, we have prepaid certain transportation costs of approximately $3.0 million to interstate pipelines. We have a contractual right to apply the prepaid amounts against future transportation charges on volumes to be shipped in the future. We monitor our actual volumes shipped to determine if the prepaid transportation costs ultimately will be recovered. In order to make that assessment we must estimate our future shipping volumes. If our estimate of our future shipping volumes were to decrease, we may not be able to utilize the prepaid transportation costs.

Derivative Contracts. At June 30, 2003, we are a party to certain derivative contracts that require us to receive and deliver physical quantities of refined petroleum products over a specified term at a specified price. Our derivative contracts are carried at fair value in the accompanying consolidated balance sheets. At June 30, 2003, our net unrealized losses on derivative contracts were approximately $1.9 million. The valuation of our derivative contracts is based on quoted prices, when available.

However, quoted prices are not available from brokers for all future periods and delivery locations in which we are committed to do business. When quoted prices are not available, we estimate the values based on a combination of published market prices and estimates based on historical market conditions. For market locations in which we have access to product via our terminals, dedicated pipeline capacity, a throughput agreement or an exchange arrangement, fair value is determined by adding the near month NYMEX futures quote to the appropriate basis differential and the transportation cost to deliver the product from the bulk trading location to the contract's specified delivery location. We estimate the basis differentials for certain deferred trading months and city-specific locations because we cannot secure a forward traded basis differential quote from a broker. In those situations, our mark-to-market model estimates the basis differentials based on a rolling historical average, which is updated quarterly. For our derivative contracts that settle against wholesale and retail pricing indices, we use a rolling historical average difference between the pricing index (e.g., Department of Energy National and OPIS Wholesale indices) and the related

NYMEX futures contract utilized to manage the commodity price risk associated with the commitment. For market locations in which we do not have access to product via our terminals, dedicated pipeline capacity, a throughput agreement or an exchange arrangement, we purchase product on a spot basis from approved vendors to satisfy our contractual obligations. In these contracts, we are exposed to the differential between the bulk trading locations and the city-specific markets, as we do not control the pipeline and terminal capacity to facilitate shipment of the physical product. Our mark-to-market model incorporates this basis differential to each city-specific location. Currently, it is not practicable for us to estimate the effects on our financial condition, results of operations, or cash flows from an unfavorable change in basis differentials.

Accrued Lease Abandonment. At June 30, 2003, we have an accrued liability of approximately $3.2 million as our estimate of the future payments we expect to pay, net of sublease payments we expect to receive from subleasing our vacated office space. The valuation of our accrued lease abandonment liability is based on the timing and amount of sublease payments we expect to receive from subleasing our vacated office space. Our estimate of the timing and amount of sublease payments is based on information received from real estate brokers.

Accrued Transportation and Deficiency Agreements. At June 30, 2003, we have an accrued liability of approximately $2.0 million as our estimate of the future payments we expect to pay for the estimated shortfall in volumes for the remainder of the terms of our transportation and deficiency

agreements. The valuation of our accrual for transportation and deficiency agreements is based on our estimate of the future volumes we expect to supply and ship with the counterparties to these agreements. We estimate the future volumes based on our historical volumes supplied and shipped with the counterparties. Our accrued liability would be adjusted if our current projections of future volumes to be supplied and shipped with the counterparties indicated a significant increase or decrease in expected volumes due to changes in the scope and breadth of our supply, distribution, and marketing operations.

Accrued Environmental Obligations. At June 30, 2003, we have an accrued liability of approximately $5.6 million as our estimate of the undiscounted future payments we expect to pay for environmental costs to remediate existing conditions attributable to past operations. The valuation of our accrued environmental obligations is based on our estimate of the remediation costs to be incurred in the future. We estimate the future remediation costs based on specific site studies using enacted laws and regulations. Estimates of our environmental obligations are subject to change due to a number of factors and judgments involved in the estimation process, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation, technology changes affecting remediation methods, alternative remediation methods and strategies, and changes in environmental laws and regulations.

SIGNIFICANT DEVELOPMENTS DURING THE YEAR ENDED JUNE 30, 2003

On July 31, 2002, we closed on the purchase of a 25,000-barrel terminal in Brownsville, Texas. The terminal provides us with additional storage and rail car handling facilities and operating synergies with our main facility in Brownsville, Texas.

On August 23, 2002, we announced the signing of a long-term terminaling agreement with P.M.I. Trading Limited to provide distribution related services and a related pipeline construction assistance agreement with P.M.I. Services North America, Inc., both affiliates of Petroleos Mexicanos, for the construction of a new 17-mile U.S. products pipeline from the U.S./Mexican border to our terminaling facility located at the port of Brownsville, Texas.

During the three months ended September 30, 2002, we relocated our supply, distribution and marketing operations from Atlanta, Georgia to our then existing office space at 370 17th Street in Denver, Colorado. During October and November 2002, our supply, distribution and marketing operations moved into our new office space at 1670 Broadway in Denver, Colorado. Our executive and administrative operations vacated our office space at 370 17th Street and joined our supply, distribution, and marketing operations at 1670 Broadway during June 2003.

On February 4, 2003, we announced the purchase of a 500,000-barrel terminal in Fairfax, Virginia that supplies products in the Washington, D.C. market, including Dulles Airport. The transaction closed on January 31, 2003.

On February 28, 2003, we closed on the purchase of all of the shares of capital stock of Coastal Fuels Marketing, Inc. and its subsidiary, Coastal Tug and Barge, Inc. from a wholly owned subsidiary of El Paso Merchant Energy Petroleum Company, or EPME-PC, along with the rights to and operations of the southeast marketing division of EPME-PC. The acquisition includes five Florida terminals, with aggregate capacity of approximately 4.9 million barrels, and a related tug and barge operation, collectively the Coastal Fuels assets. The Coastal Fuels assets primarily provide sales and storage of bunker fuel, No. 6 oil, diesel fuel and gasoline at Cape Canaveral, Port Manatee/Tampa, Port Everglades/Ft. Lauderdale and Fisher Island/Miami, and storage of asphalt at Jacksonville, Florida. The purchase price for the acquisition was approximately $156.0 million, including approximately

$37.0 million of product inventory. The purchase price included contingent consideration of approximately $25.0 million due and payable to EPME-PC upon the delivery by EPME-PC of audited financial statements of the Coastal Fuels assets. On April 25, 2003, EPME-PC delivered to us the audited financial statements of the Coastal Fuels assets and EPME-PC was paid $25.0 million on April 30, 2003.

On February 28, 2003, we executed a Credit Agreement with UBS AG that initially provided for a $250 million revolving line of credit, or the Working Capital Credit Facility, and a $200 million senior secured term loan, or the Term Loan. TransMontaigne utilized funds available under the Credit Agreement to consummate the acquisition of the Coastal Fuels assets and repay our former back credit facility.

On May 30, 2003, we consummated the sale of $200 million aggregate principal amount of $9^1/_8$% Senior Subordinated Notes due 2010 ("Old Notes") and received proceeds of $194.5 million (net of underwriters' discounts of $5.5 million). We used the net proceeds from the offering of the Old Notes to repay the Term Loan. The indenture governing the Old Notes contains covenants that, among other things, limits our ability to incur additional indebtedness, pay dividends on, redeem or repurchase our common stock, make investments, make certain dispositions of assets, engage in transaction with affiliates, create certain liens, and consolidate, merge, or transfer all or substantially all of our assets. The Old Notes are fully and unconditionally guaranteed on a joint and several basis by our subsidiaries other than minor subsidiaries that are inactive and have no assets or operations. We are a holding company for our subsidiaries, with no independent assets or operations. Accordingly, we are dependent upon the distribution of the earnings of our subsidiaries, whether in the form of dividends, advances or payments on account of inter-company obligations, to service our debt obligations. There are no restrictions on our ability or any subsidiary guarantor to obtain funds from our subsidiaries.

On June 25, 2003, we amended and restated the Working Capital Credit Facility in connection with the syndication of the facility. All outstanding borrowings under the Working Capital Credit Facility are due and payable on February 28, 2006. The Working Capital Credit Facility contains affirmative and negative covenants (including limitations on indebtedness, limitations on dividends and other distributions, limitations on certain inter-company transactions, limitations on mergers, consolidation and the disposition of assets, limitations on investments and acquisitions and limitations on liens). The Working Capital Credit Facility also contains customary representations and warranties (including those relating to due organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). It also contains certain financial covenants that are tested on a quarterly basis including a minimum fixed charge coverage ratio of 150%, a maximum funded senior debt leverage ratio of 4.5 times the last twelve months' operating results for debt covenant compliance (as defined in the credit agreement), a minimum current ratio of 120% (which excludes borrowings under the Working Capital Credit Facility from the definition of current liabilities) and a minimum consolidated tangible net worth test. In addition, we may not make aggregate expenditures in excess of $80.0 million with respect to general corporate purposes (including capital expenditures, cash paid for acquisitions, and redemption of the Series A Redeemable Convertible Preferred stock) over the term of the agreement; however, such limit shall be increased by certain cash flow amounts generated after February 28, 2003.

On June 30, 2003, we redeemed the remaining outstanding shares of Series A Convertible Preferred stock and warrants for approximately $24.4 million in cash.

SUBSEQUENT EVENTS

On May 30, 2003, we sold the Senior Subordinated Notes in a private placement transaction that was exempt from registration under the Federal Securities Act of 1933. We also entered into a registration rights agreement requiring us to make an exchange offer. On July 22, 2003, we filed a registration statement on Form S-4 with the Securities and Exchange Commission to effect the exchange offer. The registration rights agreement also requires us to use our best efforts to cause the registration statement filed with respect to the exchange offer to be declared effective by October 27, 2003 and consummate the exchange offer no later than December 26, 2003. If we do not do so, additional interest payments will be payable on the Senior Subordinated Notes. The exchange offer was not consummated as of December 26, 2003 and, therefore, we are accruing additional interest of 0.5% on the Senior Subordinated Notes until the exchange offer is consummated (resulting in a total coupon rate of 9.625%). As of February 17, 2004, the registration statement on Form S-4 has not been declared effective by the staff of the Securities and Exchange Commission.

RESULTS OF OPERATIONS BUSINESS SEGMENTS

Under SFAS No. 131, we are required to report measures of profit and loss that are used by our chief operating decision maker (our CEO) in assessing the financial performance of our business segments. Our CEO assesses the financial performance of each of our reportable segments using a financial performance measure, which we refer to as "adjusted net operating margins." There are no differences between the financial performance measure, "adjusted net operating margin," used by our CEO in evaluating the performance of our terminals, pipelines, and tugs and barges segment and the net operating margins reported for that segment in our accompanying historical financial statements. Our CEO assesses the "adjusted net operating margins" of our supply, distribution, and marketing segment using financial information that is prepared pursuant to the mark-to-market method of accounting. "Adjusted net operating margins" for the supply, distribution and marketing segment differs from net operating margins for that segment as presented in our accompanying historical statement of operations due to the treatment of our inventories discretionary volumes. In determining our "adjusted net operating margins" for our supply, distribution and marketing segment, inventories discretionary volumes held for immediate sale or exchange are reflected at fair value, which matches the treatment of our derivative and risk management contracts. Therefore, the effects of changes in the fair value of our inventories discretionary volumes held for immediate sale or exchange are included in "adjusted net operating margins" attributable to our supply, distribution and marketing segment in the period in which the fair value actually changes. "Adjusted net operating margins" also excludes the lower of cost or market write-downs on our inventories base operating volumes from our net operating margins attributable to our supply, distribution and marketing segment.

Because our inventories discretionary volumes are composed of refined petroleum products, which are commodities with established trading markets and readily ascertainable market prices, we believe that the financial performance of our supply, distribution and marketing segment can be appropriately evaluated using the mark-to-market method rather than the lower-of-cost-or-market method of accounting for our inventories discretionary volumes held for immediate sale or exchange. As a result of the implementation of EITF 02-03, our inventories discretionary volumes are carried at the lower of cost or market, while our derivative and risk management contracts are carried at fair value. As a result, if commodity prices are increasing during the end of a quarter, we may report significant losses on derivative and risk management contracts and significant deferred gains on discretionary inventory volumes held for immediate sale or exchange at the end of that quarter and report significant gains on our beginning inventories discretionary volumes held for immediate sale or exchange when they are sold in the following quarter.

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Supply, distribution and marketing adjusted net operating margins

The adjusted net operating margins attributable to our supply, distribution and marketing segment declined to $55.3 million in 2003 from $68.7 million in 2002. During the three months ended September 30, 2001, a disruption at a Chicago refinery resulted in significant volatility in basis differentials, which created significant light oil margin opportunities. That type of opportunity did not reoccur during 2003. The adjusted net operating margins from our light oil marketing declined to $37.1 million in 2003 from $54.8 million in 2002. The adjusted net operating margins from our supply management services also declined slightly to $13.0 million in 2003 from $13.9 million in 2002. The Coastal Fuels assets, which we acquired on February 28, 2003, contributed heavy oil margins of approximately $6.3 million during the year ended June 30, 2003.

Selected quarterly adjusted net operating margins for the supply, distribution and marketing segment for each of the quarters in the year ended June 30, 2003 are summarized below (in thousands):

	Three Months Ended				
	September 30, 2002	December 31, 2002	March 31, 2003	June 30, 2003	Year Ended June 30, 2003
Supply, distribution and marketing:					
Light oil margins	$ 5,825	$ 9,545	$ 8,109	$ 13,658	$ 37,137
Heavy oil margins			2,489	3,810	6,299
Supply management services margins	4,382	3,158	3,530	1,947	13,017
Trading margins, net	(2,595)	640	30	786	(1,139)

	Three Months Ended				
Adjusted net operating margins	$ 7,612	$ 13,343	$ 14,158	$ 20,201	$ 55,314
Reconciliation to net operating margins:					
Adjusted net operating margins	$ 7,612	$ 13,343	$ 14,158	$ 20,201	$ 55,314
Gains recognized on beginning inventories discretionary volumes held for immediate sale or exchange		12,644	33,490		12,644
Gains deferred on ending inventories discretionary volumes held for immediate sale or exchange		(33,490)		(5,855)	(5,855)
Change in FIFO cost basis of base operating inventory volumes		(1,421)	9,723	(7,887)	415
Lower of cost or market write-downs on base operating inventory volumes			(12,412)	(23)	(12,435)
Net operating margins historical financial statements	$ 7,612	$ (8,924)	$ 44,959	$ 6,436	$ 50,083

Prior to October 1, 2002, our inventories discretionary volumes held for immediate sale or exchange were carried at fair value with changes in fair value included in net operating margins in the period of the change in value. Effective October 1, 2002, we adjusted the carrying amount of inventories discretionary volumes to the lower of cost (FIFO) or market pursuant to the requirements of EITF 02-03. As of October 1, 2002, the fair value of our inventories discretionary volumes held for immediate sale or exchange exceeded their cost basis by approximately $12.6 million. The "Gains recognized on beginning inventories discretionary volumes" represents the net operating margins recognized on the subsequent sale of those inventories to customers during the three months ended December 31, 2002. During the last half of December 2002, we experienced significant increases in commodity prices, which resulted in the fair value of our inventories discretionary volumes held for immediate sale or exchange at December 31, 2002 exceeding their cost basis by approximately $33.5

million. That excess was recognized in net operating margins during the three months ended March 31, 2003, which was the period in which those discretionary inventory volumes were sold to customers. During the last half of June 2003, we experienced increases in certain commodity prices at certain locations, which resulted in the fair value of our inventories discretionary volumes held for immediate sale or exchange at June 30, 2003 exceeding their cost basis by approximately $5.9 million. That excess is expected to be recognized in net operating margins during the three months ended September 30, 2003, which is the period in which those discretionary inventory volumes are expected to be sold to customers.

Prior to October 1, 2002, our base operating inventory volumes were carried at original cost adjusted for impairment write-downs to current market values. Effective October 1, 2002, we adjusted the carrying amount of our base operating inventory to the lower of cost (FIFO) or market pursuant to the requirements of EITF 02-03. For the three months ended December 31, 2002, we reduced the carrying amount of our base operating inventory volumes by approximately $1.4 million due to lower commodity prices during December 2002 as compared to September 2002. For the three months ended March 31, 2003, we increased the carrying amount of our base operating inventory volumes by approximately $9.7 million due to higher commodity prices during March 2003 as compared to December 2002. For the three months ended June 30, 2003, we reduced the carrying amount of our base operating inventory volumes by approximately $7.9 million due to lower commodity prices during June 2003 as compared to March 2003.

During the three months ended March 31, 2003 and June 2003, we recognized impairment losses of approximately $12.4 million and $23,000, respectively, due to the application of the lower of cost or market rule on our base operating inventory volumes.

For the years ended June 30, 2002 and 2001, our adjusted net operating margins for the supply, distribution and marketing segment are identical to the net operating margins for such segment described under "Results of Operations Historical Financial Statements." Selected quarterly adjusted net operating margins for the supply, distribution and marketing segment for each of the quarters in the years ended June 30, 2002 and 2001 are summarized below (in thousands):

	Three Months Ended				
	September 30, 2001	December 31, 2001	March 31, 2002	June 30, 2002	Year Ended June 30, 2002
Supply, distribution and marketing:					
Light oil margins	$ 27,155	$ 11,180	$ 11,347	$ 5,121	$ 54,803
Supply management services margins	(721)	1,484	9,144	3,981	13,888
Trading margins, net	1,165	1,065	(385)	(1,789)	56
Adjusted net operating margins	$ 27,599	$ 13,729	$ 20,106	$ 7,313	$ 68,747

	Three Months Ended				
	September 30, 2000	December 31, 2000	March 31, 2001	June 30, 2001	Year Ended June 30, 2001
Supply, distribution and marketing:					
Adjusted net operating margins	$ 8,310	$ 10,865	$ 14,640	$ 12,503	$ 46,318

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Terminals, pipelines, tugs and barges adjusted net operating margins

Our adjusted net operating margins for the terminal, pipelines, tugs and barges segment are identical to the net operating margins for such segment described under "Results of Operations Historical Financial Statements." Selected quarterly adjusted net operating margins for the terminal, pipelines, tugs and barges segment for each of the quarters in the years ended June 30, 2003, 2002 and 2001 are summarized below (in thousands):

	Three Months Ended				
	September 30, 2002	December 31, 2002	March 31, 2003	June 30, 2003	Year Ended June 30, 2003
Terminals, pipelines and tugs and barges:					
Historical facilities	$ 10,928	$ 10,745	$ 10,874	$ 9,837	$ 42,384
Coastal fuels assets			1,676	3,732	5,408
Net operating margins	$ 10,928	$ 10,745	$ 12,550	$ 13,569	$ 47,792

	Three Months Ended				
	September 30, 2001	December 31, 2001	March 31, 2002	June 30, 2002	Year Ended June 30, 2002

	Three Months Ended				
Terminals and pipelines:					
Historical facilities	$ 7,669	$ 8,513	$ 9,596	$ 9,268	$ 35,046
Assets disposed	672				672
Net operating margins	$ 8,341	$ 8,513	$ 9,596	$ 9,268	$ 35,718

	Three Months Ended				
	September 30, 2000	**December 31, 2000**	**March 31, 2001**	**June 30, 2001**	**Year Ended June 30, 2001**
Terminals and pipelines:					
Historical facilities	$ 8,794	$ 9,102	$ 8,197	$ 9,389	$ 35,482
Assets disposed	3,558	2,929	2,023	1,898	10,408
Net operating margins	$ 12,352	$ 12,031	$ 10,220	$ 11,287	$ 45,890

RESULTS OF OPERATIONS HISTORICAL FINANCIAL STATEMENTS

Selected annual results of operations data are summarized below (in thousands):

	Years ended June 30,		
	2003	**2002**	**2001**
Net operating margins(1):			
Supply, distribution and marketing	$ 50,083	$ 68,747	$ 46,318
Terminals and pipelines	47,792	35,718	45,890
Total net operating margins	97,875	104,465	92,208
Selling, general and administrative expenses	(40,491)	(35,211)	(34,072)
Depreciation and amortization	(19,371)	(16,556)	(19,510)
Lower of cost or market write-downs on product linefill and tank bottom volumes	(633)	(12,963)	(18,318)
Corporate relocation and transition	(1,449)	(6,316)	
Operating income	35,931	33,419	20,308
Dividend income from petroleum related investments	374	1,450	3,060
Interest income	286	599	2,555
Interest expense and other financing costs, net	(19,981)	(21,432)	(30,065)
Gain (loss) on disposition of assets, net		(13)	22,146
Earnings before income taxes	16,610	14,023	18,004
Income tax expense	(8,510)	(5,465)	(6,666)

	Years ended June 30,		
Earnings before cumulative effect adjustment	8,100	8,558	11,338
Cumulative effect of a change in accounting principle	(1,297)		
Net earnings	6,803	8,558	11,338
Preferred stock dividends, net	(3,984)	(11,351)	(8,963)
Net earnings (loss) attributable to common stockholders	$ 2,819	$ (2,793)	$ 2,375

(1) Net operating margins represent net revenues, less direct operating costs and expenses.

Selected quarterly results of operations data for each of the quarters in the three-year period ended June 30, 2003 are summarized below (in thousands):

	Three months ended				
	September 30, 2002	December 31, 2002	March 31, 2003	June 30, 2003	Year ended June 30, 2003
Net operating margins:					
Supply, distribution and marketing	$ 7,612	$ (8,924)	$ 44,959	$ 6,436	$ 50,083
Terminals, pipelines and tugs and barges	10,928	10,745	12,550	13,569	47,792
Total net operating margins	18,540	1,821	57,509	20,005	97,875
Selling, general, and administrative	(9,331)	(8,775)	(10,440)	(11,945)	(40,491)
Depreciation and amortization	(4,256)	(4,293)	(4,851)	(5,971)	(19,371)
Lower of cost or market write-downs on product linefill and tank bottom volumes			(633)		(633)
Corporate relocation and transition	(1,084)	(365)			(1,449)
Operating income (loss)	3,869	(11,612)	41,585	2,089	35,931
Other income (expense), net	(3,004)	(2,001)	(5,484)	(8,832)	(19,321)
Income tax (expense) benefit	(329)	5,173	(13,722)	368	(8,510)
Cumulative effect adjustment		(1,297)			(1,297)
Net earnings (loss)	$ 536	$ (9,737)	$ 22,379	$ (6,375)	$ 6,803

	Three months ended				
	September 30, 2001	December 31, 2001	March 31, 2002	June 30, 2002	Year ended June 30, 2002

	Three months ended				
Net operating margins:					
Supply, distribution and marketing	$ 27,599	$ 13,729	$ 20,106	$ 7,313	$ 68,747
Terminals and pipelines	8,341	8,513	9,596	9,268	35,718
Total net operating margins	35,940	22,242	29,702	16,581	104,465
Selling, general, and administrative	(8,465)	(8,185)	(8,955)	(9,606)	(35,211)
Depreciation and amortization	(4,282)	(4,024)	(4,143)	(4,107)	(16,556)
Lower of cost or market write-downs on product linefill and tank bottom volumes	(849)	(12,114)			(12,963)
Corporate relocation and transition			(315)	(6,001)	(6,316)
Operating income (loss)	22,344	(2,081)	16,289	(3,133)	33,419
Other expense, net	(6,811)	(2,660)	(2,200)	(7,725)	(19,396)
Income tax (expense) benefit	(5,902)	1,801	(5,354)	3,990	(5,465)
Net earnings (loss)	$ 9,631	$ (2,940)	$ 8,735	$ (6,868)	$ 8,558

	Three months ended				
	September 30, 2000	December 31, 2000	March 31, 2001	June 30, 2001	Year ended June 30, 2001
Net operating margins:					
Supply, distribution and marketing	$ 8,310	$ 10,865	$ 14,640	$ 12,503	$ 46,318
Terminals and pipelines	12,352	12,031	10,220	11,287	45,890
Total net operating margins	20,662	22,896	24,860	23,790	92,208
Selling, general, and administrative	(7,237)	(8,157)	(9,102)	(9,576)	(34,072)
Depreciation and amortization	(4,847)	(4,821)	(4,927)	(4,915)	(19,510)
Lower of cost or market write-downs on product linefill and tank bottom volumes	(4,528)	(2,353)	(1,940)	(9,497)	(18,318)
Operating income (loss)	4,050	7,565	8,891	(198)	20,308
Other income (expense), net	(3,616)	(4,754)	(8,143)	14,209	(2,304)
Income tax expense	(165)	(1,068)	(284)	(5,149)	(6,666)
Net earnings	$ 269	$ 1,743	$ 464	$ 8,862	$ 11,338

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DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS FOR THE YEARS ENDED JUNE 30, 2003, 2002 AND 2001

We reported net earnings of $6.8 million for the year ended June 30, 2003, compared to net earnings of $8.6 million for the year ended June 30, 2002, and net earnings of $11.3 million for the year ended June 30, 2001. After preferred stock dividends, the net earnings (loss) attributable to common stockholders was $2.8 million, $(2.8) million and $2.4 million for the years ended June 30, 2003, 2002 and 2001, respectively. Basic earnings (loss) per common share for the years ended June 30, 2003, 2002 and 2001, was $0.07, $(0.09) and $0.08, respectively, based on 39.1 million, 31.3 million and 30.9 million weighted average common shares outstanding, respectively. Diluted earnings (loss) per share for the years ended June 30, 2003, 2002 and 2001, was $0.07, $(0.09) and $0.08, respectively, based upon 39.3 million, 31.3 million and 31.0 million weighted average diluted shares outstanding, respectively.

Terminals, pipelines, and tugs and barges

In our terminals, pipelines, and tugs and barges operations, we provide distribution related services to wholesalers, distributors, marketers, retail gasoline station operators, cruise-ship operators and industrial and commercial end-users of refined petroleum products and other commercial liquids. The net operating margins from our terminals, pipelines, and tugs and barges operations for the year ended June 30, 2003 were $47.8 million, compared to $35.7 million for the year ended June 30, 2002 and $45.9 million for the year ended June 30, 2001. On February 28, 2003, we acquired the Coastal Fuels assets, which include five terminals, a hydrant delivery system, and a tug and barge operation. The results of operations of the Coastal Fuels assets are included from the closing date of the transaction (February 28, 2003). For the year ended June 30, 2003, the Coastal Fuels assets generated revenues of approximately $12.6 million and net operating margins of approximately $5.4 million attributable to our terminals, pipelines, and tugs and barges operations. The remainder of the increase in net operating margins for 2003 as compared to 2002 is attributable to increased throughput and storage volumes at our terminals.

The decrease of $10.2 million in net operating margins for 2002 as compared to 2001 was due principally to the sale of our Little Rock facilities on June 30, 2001 and the NORCO system on July 31, 2001. For the years ended June 30, 2002 and 2001, the disposed operations generated, in the aggregate, revenues of approximately $1.3 million and $21.2 million, respectively, and net operating margins of approximately $0.7 million and $10.4 million, respectively.

The net operating margins from our terminals, pipelines, and tugs and barges operations are as follows (in thousands):

	Years ended June 30,		
	2003	**2002**	**2001**
Throughput fees	$ 30,359	$ 26,544	$ 27,945
Storage fees	26,915	18,989	20,723
Additive injection fees, net	7,921	6,611	6,593
Pipeline transportation fees	6,020	6,492	14,808
Tugs and barges	4,335		
Other	7,438	4,750	9,638
Revenue	82,988	63,386	79,707
Less direct operating costs and expenses	(35,196)	(27,668)	(33,817)
Net operating margins	$ 47,792	$ 35,718	$ 45,890

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Throughput Fees. We own and operate a terminal infrastructure that handles products with transportation connections via pipelines, barges, rail cars and trucks. We earn throughput fees for each barrel of product that is distributed at our terminals through our supply and marketing efforts, through exchange agreements, or for third parties. Terminal throughput fees are based on the volume of products distributed at the facility's truck loading racks, generally at a standard rate per barrel of product.

Exchange agreements provide for the exchange of product at one delivery location for product at a different location. We generally receive a terminal throughput fee based on the volume of the product exchanged, in addition to the cost of transportation from the receipt location to the exchange delivery location. For the years ended June 30, 2003, 2002 and 2001, we averaged approximately 47,000, 68,000 and 131,000 barrels per day, respectively, of delivered volumes under exchange agreements.

Terminal throughput fees were approximately $30.4 million, $26.5 million and $27.9 million for the years ended June 30, 2003, 2002 and 2001, respectively. For the years ended June 30, 2003, 2002 and 2001, we averaged approximately 369,000 barrels, 333,000 barrels and 337,000 barrels per day of throughput volumes at our terminals, including volumes under exchange agreements. The increase of $3.9 million in throughput fees for 2003 as compared to 2002 was due principally to increases in throughput volumes from our supply, distribution and marketing operations of approximately $3.4 million and approximately $0.8 million as a result of our acquisition of the Coastal Fuels assets, offset by decreases in throughput volumes from third parties of approximately $0.3 million.

Included in the terminal throughput fees for the years ended June 30, 2003, 2002 and 2001 are fees charged to TransMontaigne's supply, distribution and marketing segment of approximately $23.2 million, $19.0 million and $19.3 million, respectively.

Storage Fees. We lease storage capacity at our terminals to third parties and our supply, distribution and marketing segment. Terminal storage fees generally are based on a per barrel of leased capacity per month rate and will vary with the duration of the storage agreement and the type of product stored.

Terminal storage fees were approximately $26.9 million, $19.0 million and $20.7 million for the years ended June 30, 2003, 2002 and 2001, respectively. The increase of $7.9 million in storage fees for 2003 as compared to 2002 was due principally to an increase of approximately $5.9 million from our acquisition of Coastal Fuels assets, approximately $1.8 million at our Brownsville, Texas facilities and approximately $0.9 million at our Selma, North Carolina facilities offset by decreases at various other terminals.

Included in the terminal storage fees for the years ended June 30, 2003, 2002 and 2001 are fees charged to TransMontaigne's supply, distribution and marketing segment of approximately $5.9 million, $3.5 million and $4.9 million, respectively.

Additive Injection Fees, Net. We provide injection services in connection with the delivery of product at our terminals. These fees generally are based on the volume of product injected and delivered over the rack at our terminals.

Additive injection fees, net were approximately $7.9 million, $6.6 million and $6.6 million for the years ended June 30, 2003, 2002 and 2001, respectively. The increase of $1.3 million in additive injection fees, net for 2003 as compared to 2002 was due principally to an increase of approximately $0.4 million from our acquisition of Coastal Fuels assets and approximately $0.9 million from increased throughput volumes from our supply, distribution and marketing operations at our Southeast facilities.

Included in additive injection fees, net for the years ended June 30, 2003, 2002 and 2001 are fees charged to TransMontaigne's supply, distribution and marketing segment of approximately $6.7 million, $5.2 million and $4.8 million, respectively.

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Pipeline Transportation Fees. We own an interstate products pipeline operating from Mt. Vernon, Missouri to Rogers, Arkansas, or the Razorback Pipeline, together with associated terminal facilities at Mt. Vernon and Rogers. Effective June 30, 2002, we acquired for cash consideration of approximately $7.2 million the remaining 40% interest in the Razorback Pipeline system that we did not previously own. We also own and operate a proprietary pipeline in Port Everglades/Ft. Lauderdale, or the hydrant system, which we use to deliver product to cruise ships and other marine vessels for refueling, and a small intrastate crude oil gathering pipeline system, located in east Texas, or the CETEX pipeline. We earn pipeline transportation fees based on the volume of product transported and the distance from the origin point to the delivery point.

For the years ended June 30, 2003, 2002 and 2001, we earned pipeline transportation fees of approximately $6.0 million, $6.5 million and $14.8 million, respectively. On July 31, 2001, we sold the NORCO system. For the years ended June 30, 2002 and 2001, the NORCO system generated pipeline transportation fees of approximately $0.8 million and $7.9 million.

Included in the pipeline transportation fees for the years ended June 30, 2003, 2002 and 2001 are fees charged to TransMontaigne's supply, distribution and marketing segment of approximately $6.0 million, $5.6 million and $10.0 million, respectively.

Tugs and Barges. In Florida, we own and operate nine tugboats and 13 barges that deliver product to cruise ships and other marine vessels for refueling and to transport third party product from our storage tanks to our customers' facilities. Our tugboats earn fees for providing docking and other ship-assist services to cruise and cargo ships and other marine vessels. Bunkering fees are based on the volume and type of product sold, transportation fees are based on the volume of product that is shipped and the distance to the delivery point, and docking and other ship-assist services are based on a per docking per tugboat basis.

For the year ended June 30, 2003, we earned bunkering fees, transportation fees, and other ship-assist services fees of approximately $4.3 million. We acquired the tugs and barges operations on February 28, 2003 in connection with our acquisition of the Coastal Fuels assets.

Included in the tugs and barges fees for the year ended June 30, 2003 are fees charged to TransMontaigne's supply, distribution and marketing segment of approximately $2.7 million.

Other Revenue. In addition to providing storage and distribution services at our terminal facilities, we also provide ancillary services including heating and mixing of stored products and product transfer services. We also recognize gains from the sale of product to our supply, distribution and marketing operation resulting from the excess of product deposited by third parties into our terminals over the amount of product that the customer is contractually permitted to withdraw from those terminals. For the years ended June 30, 2003, 2002 and 2001, other revenue from our terminals, pipelines, and tugs and barges operations was approximately $7.4 million, $4.8 million and $9.6 million, respectively. The increase of approximately $2.6 million in other revenue for 2003 as compared to 2002 was due principally to the expansion at our Brownsville, Texas terminal facility. The decrease of approximately $4.8 million for 2002 as compared to 2001 was due principally to the disposition of the NORCO system on July 31, 2001.

Included in other revenue for the years ended June 30, 2003, 2002 and 2001 are fees charged to TransMontaigne's supply, distribution and marketing segment of approximately $3.1 million, $2.7 million and $4.2 million, respectively.

Direct Operating Costs and Expenses. The direct operating costs and expenses of our terminals, pipelines, and tugs and barges operations include the directly related wages and employee benefits, utilities, communications, maintenance and repairs, property taxes, rent, vehicle expenses,

environmental compliance costs, materials and supplies. For the years ended June 30, 2003, 2002 and 2001, the direct operating costs and expenses of the terminals, pipelines, and tugs and barges were approximately $35.2 million, $27.7 million and $33.8 million, respectively. The direct operating costs and expenses of our terminals, pipelines, and tugs and barges operations are as follows (in thousands):

	Years ended June 30,		
	2003	2002	2001
Wages and employee benefits	$ 16,266	$ 12,631	$ 14,667
Utilities and communication charges	3,616	3,024	5,214
Repairs and maintenance	9,697	7,918	9,717
Office, rentals and property taxes	4,298	4,707	5,700
Vehicles and fuel costs	860	425	690
Environmental compliance costs	3,094	2,023	2,043
Other	1,697	1,839	990
Less reimbursed costs and expenses	(4,332)	(4,899)	(5,204)
Direct operating costs and expenses	$ 35,196	$ 27,668	$ 33,817

The increase of approximately $7.5 million in direct operating costs and expenses for 2003 as compared to 2002 was due principally to the addition of the Coastal Fuels assets which resulted in approximately $7.2 million of additional direct operating costs and expenses. The decrease of approximately $6.1 million in direct operating costs and expenses for 2002 as compared to 2001 was due principally to the disposition of the Little Rock facilities and NORCO system.

Supply, distribution and marketing

The net operating margins from our supply, distribution and marketing operations for the year ended June 30, 2003 were $50.1 million, compared to $68.7 million for the year ended June 30, 2002, and $46.3 million for the year ended June 30, 2001. During the year ended June 30, 2002, we extended for an additional year, a delivered fuel price management contract with a large industrial/commercial end-user. We recognized approximately $3.0 million in net operating margins associated with this contract extension and we deferred approximately $1.7 million for the value of the supply logistical management services that we are committed to provide over the term of the supply contract.

The net operating margins from our supply, distribution and marketing operations are as follows (in thousands):

	Years ended June 30,		
	2003	2002	2001
Rack sales	$ 1,691,324	$ 1,133,069	$ 855,651

	Years ended June 30,		
Bulk sales	4,613,167	3,815,420	3,399,278
Contract sales	1,759,196	921,884	812,772
Supply management services	177,314	130,797	114,791
Gross sales	8,241,001	6,001,170	5,182,492
Cost of product sold	(8,072,877)	(5,875,791)	(5,167,077)
Net margin before other direct costs and expenses	168,124	125,379	15,415
Other direct costs and expenses:			
Net gains (losses) on risk management activities	(84,146)	(56,826)	2,872
Change in unrealized gains (losses) on derivative contracts	(21,460)	194	28,031
Lower of cost or market write-downs on base operating inventory volumes	(12,435)		
Net operating margins	$ 50,083	$ 68,747	$ 46,318

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Our supply, distribution and marketing operations typically purchase products at prevailing prices from refiners and producers at production points and common trading locations. Once we purchase these products, we schedule them for delivery to our terminals, as well as terminals owned by third parties with which we have storage or throughput agreements. From these terminal locations, we then sell our products to customers primarily through three types of arrangements: rack sales, bulk sales and contract sales.

Rack Sales. Rack sales are spot sales to commercial and industrial end-users, independent retailers, cruise-ship operators and jobbers that do not involve continuing contractual obligations to purchase or deliver product. Rack sales are priced and delivered on a daily basis through truck loading racks or marine fueling equipment. Our selling price of a particular product on a particular day at a particular terminal is a function of our supply at that terminal, our estimate of the costs to replenish the product at that terminal, our desire to reduce inventory levels at that terminal that day, and other factors. Rack sales are recognized as revenue when the product is delivered to the customer through the truck loading rack or marine fueling equipment.

Rack sales were approximately $1,691.3 million, $1,133.1 million and $855.7 million for the years ended June 30, 2003, 2002 and 2001, respectively. For the years ended June 30, 2003, 2002 and 2001, we averaged approximately 130,000 barrels, 111,000 barrels and 63,000 barrels per day, respectively, of delivered volumes under rack sales.

Bulk Sales. Bulk sales are sales of large quantities of product to wholesalers, distributors and marketers in major cash markets. We also may make a bulk sale of products while the product is being transported in the common carrier pipelines or by barge or vessel. Bulk sales are recognized as revenue when the title to the product is transferred to the customer, which generally occurs upon confirmation of the terms of the sale.

Bulk sales were approximately $4,613.2 million, $3,815.4 million and $3,399.3 million for the years ended June 30, 2003, 2002 and 2001, respectively. For the years ended June 30, 2003, 2002 and 2001, we averaged approximately 363,000 barrels, 366,000 barrels and 259,000 barrels per day, respectively, of delivered volumes under bulk sales.

Contract Sales. Contract sales are sales to commercial and industrial end users, independent retailers, cruise-ship operators and jobbers that are made pursuant to negotiated contracts, generally ranging from one to six months in duration. Contract sales provide these customers with a specified volume of product during the agreement term. At the customer's option, the pricing of the product delivered under a contract sale may be fixed at a stipulated price per gallon, or it may vary based on changes in published indices. Contract sales are recognized as revenue when the product is delivered to the customer through the truck loading rack or marine fueling equipment.

Contract sales were approximately $1,759.2 million, $921.9 million and $812.8 million for the years ended June 30, 2003, 2002 and 2001, respectively. For the years ended June 30, 2003, 2002 and 2001, we averaged approximately 136,000 barrels, 88,000 barrels and 60,000 barrels per day, respectively, of delivered volumes under contract sales.

Supply Management Services Contracts. We provide supply management services to companies and governmental entities that desire to outsource their fuel supply function and to reduce the price volatility associated with their fuel supplies. We offer three types of supply management services: delivered fuel price management, retail price management, and logistical supply management services.

Sales pursuant to supply management services contracts were approximately $177.3 million, $130.8 million and $114.8 million for the years ended June 30, 2003, 2002 and 2001, respectively.

For the years ended June 30, 2003, 2002 and 2001, we averaged approximately 14,000 barrels, 11,000 barrels and 9,000 barrels per day, respectively, of delivered volumes under supply management services contracts.

Cost of Product Sold. The cost of product sold includes the cost of the product inventory sold on a first-in, first-out basis, pipeline transportation and other freight costs, terminal throughput, additive and storage costs, and commissions. Cost of product sold is approximately $8,072.9 million, $5,875.8 million and $5,167.1 million for the years ended June 30, 2003, 2002 and 2001, respectively. Cost of product sold is as follows (in thousands):

	Years ended June 30,		
	2003	**2002**	**2001**
Inventory product costs	$ 7,922,563	$ 5,767,341	$ 5,090,561
Transportation and related charges	104,146	73,648	43,891
Throughput, storage and related charges	44,269	33,775	31,032
Other	1,899	1,027	1,593
Cost of product sold	$ 8,072,877	$ 5,875,791	$ 5,167,077

Net Gains (Losses) on Risk Management Activities. Our risk management strategy generally is intended to maintain a balanced position of forward sale and purchase commitments against our discretionary inventories held for immediate sale or exchange and future contractual delivery obligations, thereby reducing exposure to commodity price fluctuations. We evaluate our exposure to commodity price risk from an overall portfolio basis that considers the continuous movement of discretionary inventory volumes held for immediate sale or exchange and our obligations to deliver products at fixed prices through our sales contracts and supply management contracts. Our physical inventory position, which includes firm commitments to buy and sell product, is offset with risk management contracts, principally futures contracts on the NYMEX.

When we purchase refined petroleum products, we enter into futures contracts to sell a corresponding amount of product to protect against price fluctuations for the underlying commodity. When we ultimately sell the underlying inventory to a customer, we unwind the related risk management contract. In order to effectively manage commodity price risk, we must predict when we will sell the underlying product. If we fail to accurately predict the timing of those future sales, and the product remains in our inventory longer than the expiration date of the futures contract, we must settle the old futures contract and enter into a new futures contract to sell the product to manage the commodity price risk against the same inventory. We refer to this as "rolling" the risk management contracts. During a period of rising prices, our risk management contracts (i.e., short futures contracts) that are entered into to reduce our risk to commodity price changes associated with our discretionary inventory volumes held for immediate sale or exchange will decline in value resulting in a loss.

Net gains (losses) on risk management activities were approximately $(84.1) million, $(56.8) million and $2.9 million for the years ended June 30, 2003, 2002 and 2001, respectively, due principally to (rising) declining commodity prices during these periods.

Lower of Cost or Market Write-Downs on Base Operating Inventory Volumes. During the year ended June 30, 2003, we recognized impairment losses of approximately $12.4 million due to lower of cost or market write-downs on the base operating inventory volumes due principally to declining prices at the end of a quarterly reporting period. During the years ended June 30, 2002 and 2001, we did not report any of our inventory volumes as base operating inventory volumes. During these years our base operating inventory volumes were a component of our product linefill and tank bottom volumes.

Costs and expenses

Selling, general and administrative expenses for the year ended June 30, 2003 were $40.5 million, compared to $35.2 million for the year ended June 30, 2002, and $34.1 million for the year ended June 30, 2001. Selling, general and administrative expenses are as follows (in thousands):

	Years ended June 30,		
	2003	2002	2001
Wages and employee benefits	$ 28,324	$ 25,278	$ 25,060
Office costs, utilities and communication charges	4,878	4,894	4,308
Accounting and legal expenses	2,502	1,306	1,233
Property and casualty insurance	2,831	1,871	1,771
Other	1,956	1,862	1,700
Selling, general and administrative expenses	$ 40,491	$ 35,211	$ 34,072

Depreciation and amortization for the years ended June 30, 2003, 2002 and 2001, was $19.4 million, $16.6 million and $19.5 million, respectively. The increase of $2.8 million in depreciation and amortization for 2003 as compared to 2002 is principally related to depreciation and amortization on new additions to property, plant, and equipment. The decrease of $2.9 million in depreciation and amortization in 2002 as compared to 2001 was due primarily to the disposition of the Little Rock facilities and NORCO system.

During the years ended June 30, 2003, 2002 and 2001, we recognized impairment losses of approximately $0.6 million, $13.0 million and $18.3 million, respectively, due to write-downs on the product linefill and tank bottom volumes.

We recognized special charges of $1.4 million and $6.3 million during the years ended June 30, 2003 and 2002, respectively, related to our corporate relocation and transition. As of June 30, 2003 we have completed the relocation of our employees from Atlanta, Georgia to Denver, Colorado and paid the remaining special termination benefits and transition bonuses.

Other income and expenses

Dividend income from petroleum-related investments for the year ended June 30, 2003 was $0.4 million, compared to $1.5 million for the year ended June 30, 2002, and $3.1 million for the year ended June 30, 2001. The decrease of $1.1 million in dividend income for 2003 as compared to 2002 was due principally to a decrease of $0.3 million in dividends received from Lion Oil Company and the absence of $0.8 million in dividends received from West Shore. We sold a portion of our investment in West Shore on July 27, 2001 and our remaining investment on October 29, 2001. The decrease of $1.6 million in dividend income in 2002 as compared to 2001 was due principally to the decline in dividends received from West Shore.

Interest income for the year ended June 30, 2003 was $0.3 million, as compared to $0.6 million for the year ended June 30, 2002, and $2.6 million for the year ended June 30, 2001. Pursuant to our cash management practices, excess cash balances are used to pay down our outstanding borrowings under our credit facility and commodity margin loan.

Interest expense for the year ended June 30, 2003 was $14.7 million, compared to $12.4 million during the year ended June 30, 2002, and $17.8 million during the year ended June 30, 2001. Interest expense is as follows (in thousands):

Years ended June 30,		
2003	2002	2001

	Years ended June 30,		
Working capital credit facility	$ 1,724	$	$
Former bank credit facility	4,559	5,179	12,924
Letters of credit	351	338	216
Commodity margin loan	200	499	740
Interest rate swap	3,902	4,597	
Term loan	2,441		
Senior subordinated notes	1,521		
Senior notes		1,823	3,890
Other	7		
Interest expense	$ 14,705	$ 12,436	$ 17,770

Other financing costs for the year ended June 30, 2003 were $5.3 million, compared to $9.0 million for the year ended June 30, 2002, and $12.3 million for the year ended June 30, 2001. The decrease of $3.7 million in other financing costs for 2003 as compared to 2002 was due principally to an unrealized gain on the settlement of our interest rate swap of $2.2 million during 2003, as compared to an unrealized loss on an interest rate swap of $(2.3) million during 2002, and a decrease in the early payment penalty of $1.9 million, offset by an increase in the write-off of debt issuance costs of $2.8 million related to the repayment of our former bank credit facility and the Term Loan. On February 28, 2003, we settled our obligations under the swap agreement when we repaid our former bank revolving credit facility. On May 30, 2003, we repaid the Term Loan with the proceeds from the issuance of the Senior Subordinated Notes.

Gain (loss) on the disposition of assets for the year ended June 30, 2002 consists of $(9.9) million loss on the sale of West Shore, $8.6 million gain on the sale of the NORCO system, $1.4 million gain on the sale of our investment in ST Oil Company, and $(0.1) million loss on the sale of other assets. Gain on the disposition of assets was $22.1 million for the year ended June 30, 2001 due to the sale of the Little Rock facilities.

Income taxes

Income tax expense was $8.5 million for the year ended June 30, 2003, compared to $5.5 million for the year ended June 30, 2002, and $6.7 million for the year ended June 30, 2001. The effective combined federal and state income tax rate was 51.2%, 39.0% and 37.0% for the years ended June 30, 2003, 2002 and 2001, respectively. The effective combined rate for 2003 includes a provision of approximately $1.7 million for a change in cumulative temporary differences.

Cumulative effect adjustment for a change in accounting principle

As a result of the consensus reached on EITF 02-03, we are no longer permitted to carry our inventories discretionary volumes held for immediate sale or exchange at fair value nor are we permitted to carry our base operating inventory volumes at original cost adjusted for impairment write-downs. Effective October 1, 2002, we adjusted the carrying amount of our inventories discretionary volumes to the lower of cost (FIFO) or market pursuant to the requirements of EITF 02-03. The change in the carrying amount of our inventories discretionary volumes has been

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reflected in the accompanying consolidated statement of operations as a cumulative effect adjustment for a change in accounting principle.

Preferred stock dividends

Preferred stock dividends on our Series A Convertible Preferred stock were $1.2 million, $11.4 million and $9.0 million for the years ended June 30, 2003, 2002 and 2001, respectively. The decrease in the current year dividend resulted from a reduction in the number of shares of Series A Convertible Preferred stock outstanding during the current period. The terms of the Series A Convertible Preferred Stock included an increase in the annual dividend rate from 5% of the liquidation value to 16% of the liquidation value commencing January 1, 2004. Therefore, on June 28, 2002, we entered into an agreement with the holders of the Series A Convertible Preferred stock, or the Preferred Stock Recapitalization Agreement, to redeem a portion of the outstanding Series A Convertible Preferred stock and warrants in exchange for cash, shares of common stock, and shares of a newly created and designated preferred stock, or the Series B Redeemable Convertible Preferred Stock, to reduce the financial impact of the scheduled increase in the dividend rate. The Preferred Stock Recapitalization Agreement resulted in the redemption of 157,715 shares of Series A Convertible Preferred stock and warrants to purchase 9,841,493 shares of common stock in exchange for the (i) issuance of 72,890 shares of Series B Redeemable Convertible Preferred Stock with a fair value of approximately $80.9 million, (ii) issuance of 11,902,705 shares of common stock with a fair value of approximately $59.5 million, and (iii) a cash payment of approximately $21.3 million. On June 30, 2003, we redeemed the remaining 24,421 shares of Series A Convertible Preferred stock and warrants that were outstanding for a cash payment of approximately $24.4 million.

Preferred stock dividends on our Series B Redeemable Convertible Preferred Stock were $2.8 million, $nil and $nil for the years ended June 30, 2003, 2002 and 2001. There were no shares of Series B Redeemable Convertible Preferred Stock outstanding during the years ended June 30, 2002 and 2001. The initial carrying amount of the Series B Redeemable Convertible Preferred Stock of approximately $80.9 million will be decreased ratably over its 5-year term until it equals its liquidation value of approximately $72.9 million with an equal reduction in the amount of preferred stock dividends recorded for financial reporting purposes. The amount of the dividend recognized for financial reporting purposes is composed of the amount of the dividend payable to the holders of the Series B Redeemable Convertible Preferred Stock of $4.4 million, offset by the amortization of the premium on the carrying amount of the Series B Redeemable Convertible Preferred Stock of $1.6 million.

LIQUIDITY, CAPITAL RESOURCES, AND COMMODITY PRICE RISK

At June 30, 2003, our current assets exceeded our current liabilities by $63.9 million, compared to $168.1 million at June 30, 2002. The decrease of $104.2 million in working capital is due principally to the classification of the outstanding borrowings on the Working Capital Credit Facility as current liabilities at June 30, 2003. In the accompanying consolidated balance sheet at June 30, 2003, we have classified the outstanding borrowings under the Working Capital Credit Facility as a current liability because we have pledged our current assets as security for the facility and it currently is our expectation that we will repay the outstanding borrowings within one year of the balance sheet date.

The increase in accounts receivable of $103.6 million is due principally to increased supply, distribution, and marketing volumes coupled with an increase in commodity prices. Our gross revenues for the supply, distribution and marketing operations were approximately $777.4 million and $564.8 million for the one month ended June 30, 2003 and 2002, respectively. Our average days sales in accounts receivable was approximately 12 days and 10 days for the years ended June 30, 2003 and 2002, respectively.

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At June 30, 2003, our inventories discretionary volumes are composed of volumes held for immediate sale or exchange and volumes held for base operations. Volumes held for immediate sale or exchange generally are subject to price risk management activities, whereas, volumes held for base operations generally are not subject to price risk management activities. At June 30, 2002 our inventories discretionary volumes are composed solely of volumes held for immediate sale or exchange. Our inventories discretionary volumes are presented in the accompanying consolidated balance sheet as current assets and are carried at the lower of cost or market at June 30, 2003. Inventories discretionary volumes are as follows (in thousands):

	June 30, 2003		June 30, 2002	
	Amount	**Bbls**	**Amount**	**Bbls**
Volumes held for immediate sale or exchange	$ 130,492	3,890	$ 175,169	5,749
Volumes held for base operations	96,426	2,922		
Inventories discretionary volumes	$ 226,918	6,812	$ 175,169	5,749

Prior to October 1, 2002, our volumes held for base operations were included as a component of our product linefill and tank bottom volumes. On October 1, 2002, in connection with the adoption of EITF 02-03, we transferred for financial reporting purposes approximately 1.3 million barrels of product to inventories discretionary volumes held for base operations from product linefill and tank bottom volumes. Based on the level of our operations at March 1, 2003, we determined that we should increase our base operating inventory volumes to approximately 2.9 million barrels. Changes in our operation, such as the acquisition of additional terminals, may result in changes in the volume of our base operating inventory volumes. The activity in our base operating inventory volumes is summarized as follows (in thousands):

	Amount	**Barrels**
As of June 30, 2002	$	
Transfer from minimum volumes	28,959	1,280
Cumulative effect adjustment for adoption of EITF 02-03	10,552	
Expansion of existing operations	38,873	875

		Amount	Barrels
Acquisition of Coastal Fuels assets		30,062	767
Change in FIFO cost basis		415	
Lower of cost or market write-down		(12,435)	
As of June 30, 2003	$	96,426	2,922

Our product linefill and tank bottom volumes are not held for sale or exchange in the ordinary course of business and, therefore, we do not manage the commodity price risks associated with these volumes. At June 30, 2003, our product linefill and tank bottom volumes consist of refined products held in our proprietary pipelines and tank bottoms. At June 30, 2002, our product linefill and tank bottom volumes consisted of tank bottoms, linefill in our proprietary pipelines, and in-transit volumes on common carrier pipelines. The adoption of EITF 02-03 necessitated the transfer for financial reporting purposes of approximately 1.3 million barrels of our original product linefill and tank bottom

volumes, representing in-transit volumes on common carrier pipelines, to inventories discretionary volumes. Product linefill and tank bottom volumes are as follows (in thousands):

	June 30, 2003			June 30, 2002		
	Amount		Bbls	Amount		Bbls
Volumes held for base operations	$			$	28,959	1,280
Linefill and tank bottom volumes		22,017	877		16,339	720
	$	22,017	877	$	45,298	2,000

At June 30, 2003 and 2002, our product linefill and tank bottom volumes are presented in the accompanying consolidated balance sheet as non-current assets and are carried at original cost adjusted for impairment write-downs to current market values. At June 30, 2003 and 2002, the weighted average adjusted cost basis of our product linefill and tank bottom volumes was $0.60 and $0.54 per gallon, respectively. Product linefill and tank bottom volumes consist of the following (in thousands):

	June 30, 2003			June 30, 2002		
	Amount		Bbls	Amount		Bbls
Gasolines	$	13,020	497	$	27,855	1,200
Distillates		7,449	319		17,443	800
No. 6 oil		1,548	61			
Product linefill and tank bottom volumes	$	22,017	877	$	45,298	2,000

The activity in our product linefill and tank bottom volumes is summarized as follows (in thousands):

		Amount	Barrels
As of June 30, 2002	$	45,298	2,000
Transfer to discretionary volumes		(28,959)	(1,280)
Acquisition of Coastal Fuels assets		6,311	157
Lower of cost or market write-down		(633)	
As of June 30, 2003	$	22,017	877

The following table indicates the maturities of our derivative contracts, including the credit quality of our counterparties to those contracts with unrealized gains at June 30, 2003.

	Fair value of contracts (in thousands)			
	Maturity less than 1 year	Maturity 1-3 years	Maturity in excess of 3 years	Total
Unrealized gain position asset				
Investment grade	$ 3,970			$ 3,970
Non-investment grade	2,667	1,683		4,350
No external rating	10,180	202		10,382
	16,817	1,885		18,702
Unrealized loss position liability	(20,151)	(423)		(20,574)
Net unrealized loss position liability	$ (3,334)	1,462		$ (1,872)

At June 30, 2003, the unrealized gain on our derivative contracts with non-investment grade counterparties was approximately $4.4 million. A single customer represented approximately $2.4 million of that unrealized gain. At June 30, 2003, we also had derivative contracts with that customer that were in an unrealized loss position of approximately $(4.1) million. Therefore, the net unrealized loss on all our derivative contracts with that customer was approximately $(1.7) million at June 30, 2003.

The following table includes information about the changes in the fair value of our derivative contracts with that customer for the year ended June 30, 2003 (in thousands):

Fair value at June 30, 2002	$ 11,041
Amounts realized or otherwise settled during the year	(4,886)
Change in fair value attributable to change in commodity prices	(10,911)
Other changes in fair value	3,074
Fair value at June 30, 2003	$ (1,682)

Excluding the acquisitions of Coastal Fuels assets and the products terminals in Brownsville, Texas and Fairfax, Virginia, capital expenditures for the year ended June 30, 2003 were $10.8 million for terminal and pipeline facilities and assets to support these facilities. Excluding acquisitions, capital expenditures for the year ending June 30, 2004, are estimated to be approximately $12.0 million, which includes approximately $4.2 million of capital expenditures to maintain our existing facilities. Future capital expenditures will depend on numerous factors, including the availability, economics and cost of appropriate acquisitions which we identify and evaluate; the economics, cost and required regulatory approvals with respect to the expansion and enhancement of existing systems and facilities; customer demand for the services we provide; local, state and federal governmental regulations; environmental compliance requirements; and the availability of debt financing and equity capital on acceptable terms.

On June 25, 2003, we amended and restated the Working Capital Credit Facility in connection with the syndication of the facility. Our Working Capital Credit Facility as in effect at June 30, 2003 provides for a maximum borrowing line of credit that was the lesser of (i) $275 million and (ii) the borrowing base (as defined; $350 million at June 30, 2003). The maximum borrowing amount is reduced by the amount of letters of credit that are outstanding. The borrowing base is a function of our cash, accounts receivable, inventory, exchanges, margin deposits, open positions of energy services and risk management contracts, outstanding letters of credit, and outstanding indebtedness as defined in the facility. At June 30, 2003, we had borrowings of $175 million outstanding and letters of credit of $4.9 million outstanding under the Working Capital Credit Facility. We also had the ability to borrow an additional $95.1 million under the facility based on the borrowing base computation at June 30, 2003. All outstanding borrowings under the Working Capital Credit Facility are due and payable on February 28, 2006.

The Working Capital Credit Facility is our primary means of short-term liquidity to finance our working capital requirements and, as such, it is material to our operations. The Working Capital Credit Facility contains affirmative and negative covenants (including limitations on indebtedness, limitations on dividends and other distributions, limitations on certain inter-company transactions, limitations on mergers, consolidation and the disposition of assets, limitations on investments and acquisitions and limitations on liens). The Working Capital Credit Facility also contains customary representations and warranties (including those relating to due organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy

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events). It also contains certain financial covenants that are tested on a quarterly basis including a minimum fixed charge coverage ratio of 150%, a maximum funded senior debt leverage ratio of 4.5 times the last twelve months' operating results for debt covenant compliance (as defined in the credit agreement), a minimum current ratio of 120% (which excludes borrowings under the Working Capital Credit Facility from the definition of current liabilities) and a minimum consolidated tangible net worth test. In addition, we may not make aggregate expenditures in excess of $80.0 million with respect to general corporate purposes (including capital expenditures, cash paid for acquisitions, and redemption of the Series A Redeemable Convertible Preferred stock) over the term of the agreement; however, such limit shall be increased by certain cash flow amounts generated after February 28, 2003. As of June 30, 2003, we were in compliance with all covenants included in the Working Capital Credit Facility.

We believe that the fixed charge coverage test is the most important and, potentially, restrictive of our financial covenants included in the Working Capital Credit Facility. The fixed charge coverage ratio is based on a defined financial performance measure within the Working Capital Credit Facility known as "fixed charges EBITDA." The fixed charge coverage ratio states that for each fiscal quarter of the Company, the ratio (expressed as a percentage) of the "fixed charges EBITDA" of the Company and its subsidiaries for the period of four consecutive fiscal quarters then ended to consolidated fixed charges of the Company and its subsidiaries for such period shall equal or exceed 150%. If we were to fail the fixed charge ratio covenant, or any other covenant contained in the Working Capital Credit Facility, we would seek a waiver from our lenders under such facility. If we were unable to obtain a waiver from our lenders, we would be in breach of the Working Capital Credit Facility and the lenders would be entitled to declare all outstanding borrowings immediately due and payable. In addition, a default under the Working Capital Credit Facility would trigger a cross-default provision in the indenture covering our Senior Subordinated Notes.

On May 30, 2003, we consummated the sale and issuance of $200 million aggregate principal amount of $9^1/_8$% Senior Subordinated Notes due 2010 ("Old Notes") and received proceeds of $194.5 million (net of underwriters' discounts of $5.5 million). We used the net proceeds from the offering of the Old Notes to repay the Term Loan. The Old Notes mature on June 1, 2010 and interest is payable semi-annually in arrears on each June 1 and December 1 commencing on December 1, 2003. The Old Notes are unsecured and subordinated to all of our existing and future senior debt. Upon certain change of control events, each holder of the Old Notes may require us to repurchase all or a portion of its notes at a purchase price equal to 101% of the principal amount thereof, plus accrued interest.

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We have contractual obligations that are required to be settled in cash. The amounts of our contractual obligations are as follows (in thousands):

	Years ending June 30,					
	2004	**2005**	**2006**	**2007**	**2008**	**Thereafter**
Debt	$ 4,534	$	$ 175,000	$	$	$ 200,000
Preferred stock				72,890		
Transportation and deficiency agreements	976	637	400			
Operating leases:						
Existing office space	1,251	1,558	1,574	1,541	1,507	5,574
Vacated office space (excluding estimated sublease rentals)	1,432	1,075	1,097	928	370	763
Terminal and pipeline capacity	2,837	2,318	601	162		
Property and equipment	248	157	120	58		

	Years ending June 30,					
Total contractual obligations to be settled in cash	$ 11,278	$ 5,745	$ 178,792	$ 75,579	$ 1,877	$ 206,337

See Notes 9, 11, 12 and 17 of Notes to consolidated financial statements.

We have outstanding letters of credit with third parties in the amount of $4.9 million, which expire within one year.

We believe that our current working capital position; future cash expected to be provided by operating activities; available borrowing capacity under our working capital credit facility and commodity margin loan; and our relationship with institutional lenders and equity investors should enable us to meet our planned capital and liquidity requirements through at least the maturity date of our Working Capital Credit Facility (February 2006).

Net cash provided (used) by operating activities was $33.3 million for the year ended June 30, 2003, as compared to $(101.5) million for the year ended June 30, 2002, and $51.9 million for the year ended June 30, 2001.

Net cash provided (used) by investing activities was $(170.6) million for the year ended June 30, 2003, as compared to $102.8 million for the year ended June 30, 2002, and $(19.0) million for the year ended June 30, 2001.

Net cash provided (used) by financing activities was $134.4 million for the year ended June 30, 2003, as compared to $3.8 million for the year ended June 30, 2002, and $(61.1) million for the year ended June 30, 2001.

NEW ACCOUNTING PRONOUNCEMENTS WITH DELAYED EFFECTIVE DATES

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)*. SFAS No. 146 applies to costs associated with an exit activity that does not involve an entity newly acquired in a business combination or with a disposal activity covered by SFAS No. 144. A liability for a cost associated with an exit or disposal activity generally shall be recognized and measured initially at its fair value in the period in which the liability is incurred. In periods subsequent to initial measurement, changes to the liability shall be measured using the credit-adjusted risk-free rate that was

used to measure the liability initially. We are required to adopt the provisions of SFAS No. 146 for exit or disposal activities initiated after December 31, 2002. In connection with our corporate relocation and transition, we accrued our expected lease abandonment costs and severance costs. After its effective date, SFAS No. 146 does not permit the accrual of expected costs in advance of those costs being incurred. Had SFAS No. 146 been in effect as of July 1, 2001, we believe that approximately $3.1 million of accrued lease abandonment costs and approximately $0.7 million of accrued severance benefits would not have been recognized during the year ended June 30, 2002.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," which addresses the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 requires, among other things, a financial instrument issued in the form of shares that is mandatorily redeemable due to an unconditional obligation of the issuer to redeem the shares by transferring its assets at a specified date be classified as a liability on the balance sheet. We were required to adopt the provisions of SFAS No. 150 in our interim financial statements for the three months ending September 30, 2003. The adoption of SFAS No. 150 did not have an impact on our consolidated financial statements. Our Series B Redeemable Convertible Preferred stock will continue to be presented between liabilities and common equity in our accompanying consolidated balance sheet. Pursuant to SFAS No. 150, our Series B Redeemable Convertible Preferred stock is not required to be presented as a liability in the accompanying consolidated balance sheet because holders of our Series B Redeemable Convertible Preferred stock have the right, at the holder's option, to convert the preferred shares into common shares.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk policies

We are exposed to market risk through changes in commodity prices and interest rates as discussed below. We have no foreign currency exchange risks. Risk management policies have been established by our Risk Management Committee, RMC, to monitor and control these market risks. Our RMC is composed primarily of our senior executives. Our RMC has responsibility for oversight with respect to our risk management policies and our Audit Committee of the Board of Directors approves the financial exposure limits.

Commodity risk

Our earnings, cash flow and liquidity may be affected by a variety of factors beyond our control, including the supply of, and demand for refined petroleum products. Demand for refined petroleum products depends on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and the extent of government regulation. As a result, refined petroleum products experience price volatility, which directly impacts our revenues and net operating margins. Our net operating margins are not impacted as much by the absolute price of the commodities as they are by the impact that the absolute price has upon supply and demand of refined petroleum products and the related local market supply and demand imbalances.

Relative month-end commodity prices from June 30, 2001 to June 30, 2003 (NYMEX close on the last day of the month) are as follows:

	Crude Oil	Heating Oil	Gasoline
6/30/01	$ 26.25	$ .709	$ .721
7/31/01	$ 26.35	$ .697	$ .732
8/31/01	$ 27.20	$ .766	$ .806
9/30/01	$ 23.43	$ .664	$ .680
10/31/01	$ 21.18	$ .598	$ .552
11/30/01	$ 19.44	$ .532	$ .534
12/31/01	$ 19.84	$ .551	$ .573
1/31/02	$ 19.48	$ .523	$ .559
2/28/02	$ 21.74	$ .563	$ .581
3/31/02	$ 26.31	$ .669	$ .825
4/30/02	$ 27.29	$ .689	$ .823
5/31/02	$ 25.31	$ .630	$ .738
6/30/02	$ 26.86	$ .680	$ .794
7/31/02	$ 27.02	$ .676	$ .830
8/31/02	$ 28.98	$ .748	$ .814
9/30/02	$ 30.45	$ .802	$ .814
10/31/02	$ 27.22	$ .744	$ .864
11/30/02	$ 26.89	$ .757	$ .734
12/31/02	$ 31.20	$ .866	$ .865
1/31/03	$ 33.51	$ .959	$ .976
2/28/03	$ 36.60	$ 1.256	$ 1.038
3/31/03	$ 31.04	$ .792	$ .944
4/30/03	$ 25.80	$ .761	$ .843
5/31/03	$ 29.56	$ .754	$ .868
6/30/03	$ 30.19	$ .781	$ .870

We have developed risk management strategies to manage the commodity price risk associated with our discretionary inventories held for immediate sale or exchange and derivative contracts. Our risk management strategy generally is intended to maintain a balanced position of forward sale and purchase commitments, discretionary inventories held for immediate sale or exchange and risk management contracts, thereby reducing exposure to commodity price fluctuations. We evaluate our exposure to commodity price risk from an overall portfolio basis that considers the continuous movement of discretionary inventory volumes held for immediate sale or exchange and our obligations to deliver and receive products at fixed prices through our derivative sales and purchase contracts. Our physical inventory position, which includes firm commitments to buy and sell product, is reconciled daily and that net position is offset with risk management contracts.

The value of petroleum products in any U.S. metropolitan area is the sum of the commodity price as reflected on the NYMEX and the basis differential for that city-specific delivery location. The objective of our risk management strategy is to minimize the financial impact on TransMontaigne from changes in petroleum commodity prices affected by world-wide crude oil and petroleum products supply and demand disruptions (e.g., Middle East war, OPEC production quotas, foreign import disruptions due to hurricanes and other weather-related occurrences, foreign country work stoppages, and major refinery outages). We utilize NYMEX futures contracts to manage our exposure to the impact of these "world-wide" events. We generally do not manage the financial impact on us from changes in basis differentials affected by local market supply and demand disruptions (e.g., local pipeline delivery disruptions (such as the August 2003 pipeline disruption that affected Arizona markets), local refinery outages, periodic change in local government specifications for gasolines and distillates, local seasonality in product demand, and disruptions due to local weather related occurrences).

We believe that the historical results of our risk management strategies generally produce the financial outcomes we expect. We believe that the utilization of NYMEX futures contracts to manage the commodity price risk associated with our forward sale and purchase commitments and discretionary inventories held for immediate sale or exchange minimizes the financial impact on TransMontaigne from changes in "world-wide" commodity prices. During periods of rising commodity prices, we expect to recognize significant net margin before other direct costs and expenses from the sale of the physical product offset by significant net losses on risk management activities resulting in overall net operating margins that are in line with expectations. Conversely, during periods of declining commodity prices, we expect to recognize minimal, if any, net margin before other direct costs and expenses from the sale of the physical product offset by significant net gains on risk management activities resulting in overall net operating margins that are, again, in line within expectations. Because the risk management strategies do not qualify for "hedge accounting" for financial reporting purposes, we report the net gains or losses from risk management activities separately on the face of our consolidated statement of operations. For the years ended June 30, 2003, 2002 and 2001, we recognized net gains (losses) on risk management activities of approximately $(84.1) million, $(56.8) million and $2.9 million, respectively.

During the three months ended March 31, 2003, we re-evaluated our risk management strategy in light of the acquisition of the Coastal Fuels assets, which expanded our product offering to include bunker fuel and No. 6 oil, the expansion of our supply, marketing and distribution activities along the Mississippi and Ohio rivers, and the significance of the overall losses we were incurring on our NYMEX futures contracts. Upon completion of our analysis, we concluded that our base operating inventory volumes, which are necessary to support our operations, would be increased from approximately 1.3 million barrels to approximately 2.9 million barrels, and that our risk management policy should permit discretion in determining the volume of inventories that would be managed with NYMEX futures contracts at any particular point in time. Consequently, our risk management policy

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has been amended to allow our management team the discretion to manage the commodity price risk relating to up to 500,000 barrels of our base operating inventory volumes, which would reduce the total unmanaged inventory (base operating volumes and product linefill and tank bottom volumes) to approximately 3.3 million barrels, or to leave unmanaged up to 500,000 barrels of our discretionary inventory held for immediate sale or exchange, which would increase our total unmanaged inventory to approximately 4.3 million barrels. The principal objective of the amendment to our risk management policy is to allow management discretion to capture financial gains, or prevent financial losses, on predictable commodity price movements with respect to up to 500,000 barrels of physical product. We decide whether to manage the commodity price risk relating to a portion of our base operating inventory or to leave a portion of our discretionary inventory unmanaged depending on our expectations of future market changes. To the extent that we do not manage the commodity price risk relating to a portion of our inventory and commodity prices move adversely, we could suffer losses on that inventory. If, however, prices move favorably, we would realize a gain on the sale of the inventory that we would not realize if substantially all of our inventory was managed. At June 30, 2003, we were subject to commodity price risk on approximately 60,000 barrels of discretionary inventories held for immediate sale or exchange because those barrels were not offset with risk management contracts or future contractual delivery obligations.

Our RMC reviews our discretionary inventory volumes held for immediate sale or exchange, open positions in fixed-price forward sale and purchase commitments, and risk management contracts on a regular basis in order to ensure compliance with our inventory and risk management policies.

When we purchase refined petroleum products, we generally enter into NYMEX futures contracts to protect against price fluctuations for the underlying commodity. Futures contracts are obligations to purchase or sell a specific volume of inventory at a fixed price at a future date. The NYMEX requires an initial margin deposit to open a futures contract. At June 30, 2003 and 2002, we had approximately $5.2 million and $8.6 million, respectively, on deposit to cover our initial margin requirements on open NYMEX futures contracts. NYMEX futures contracts also require daily settlements for changes in commodity prices. Unfavorable commodity price changes subject us to variation margin calls that require us to make cash payments to the NYMEX in amounts that may be material. At June 30, 2003, a $0.05 per gallon unfavorable change in commodity prices would have required us to make a cash payment of approximately $0.8 million to cover the variation margin. Conversely, a $0.05 per gallon favorable change in commodity prices would have permitted us to receive approximately $0.8 million. We use our credit lines to fund these margin calls, but such funding requirements could exceed our ability to access capital. We have the contractual right to request that the counterparties to our supply management services contracts post additional letters of credit or make additional cash deposits with us to assist us in meeting our obligations to cover our margin requirements.

When we ultimately sell the underlying inventory to a customer, we unwind the related futures contract. If there is correlation in price changes between the forward price curve in the futures market and the value of physical products in the cash market, the net changes in our variation margin position should be offset by the net operating margins we receive when we sell the underlying discretionary inventory. Therefore, in order to effectively manage commodity price risk, we must predict when we will sell the underlying product. If we fail to accurately predict the timing of those future sales, and the product remains in our inventory longer than the expiration date of the futures contract, we must settle the old futures contract and enter into a new futures contract to sell the product to manage the commodity price risk against the same inventory. We refer to this as "rolling" the risk management contracts. Included in the net gains (losses) on risk management activities for the years ended June 30, 2003 and 2002, are gains (losses) of approximately $(32.8) million and $1.1 million, respectively, from

unwinding the original futures contract in an (unfavorable) favorable futures market and rolling the risk management contracts in an (unfavorable) favorable futures market. It is not practicable to obtain the information for the year ended June 30, 2001. Furthermore, we may be unable to precisely match the underlying product in our futures contracts with the exact type of product in our physical inventory. To the extent that price fluctuations of the product covered by the NYMEX futures contract does not match the price fluctuations of the product in our physical inventory, our exposure may not be mitigated.

At June 30, 2003, a $0.05 per gallon unfavorable change in commodity prices relative to our open positions in derivative sales and purchase contracts and risk management contracts would have resulted in the recognition of a loss (realized and unrealized) of approximately $6.0 million. However, the fair value of our discretionary inventory held for immediate sale or exchange would have increased by approximately $6.1 million. The gain from the increase in the fair value of our discretionary inventory volumes held for immediate sale or exchange may not be recognized for financial reporting purposes until those volumes have been sold to customers, which may be in an accounting period subsequent to the accounting period in which the losses on derivative contracts and risk management contracts are recognized.

Fixed-price forward sale and purchase commitments are subject to risks relating to market value fluctuations, as well as counterparty credit and liquidity risk. We have established procedures to continually monitor these contracts in order to minimize credit risk, including the establishment and review of credit limits, margin requirements, master net out arrangements, letters of credit and other guarantees.

Interest rate risk

At June 30, 2003, we had outstanding borrowings of $175.0 million under our Working Capital Credit Facility. We are exposed to interest rate risk because the Working Capital Credit Facility is a variable-rate-based credit facility. The interest rate is based on the lender's alternate base rate plus a spread, or LIBOR plus a spread, in effect at the time of the borrowings and is adjusted monthly, bi-monthly, quarterly or semi-annually. Based on the outstanding balance of our variable-interest-rate debt at June 30, 2003, and assuming market interest rates increase or decrease by 100 basis points, the potential annual increase or decrease in interest expense is approximately $1.8 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following consolidated financial statements should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this annual report.

TransMontaigne Inc. and Subsidiaries:

Independent auditors' report

The Board of Directors and Stockholders
TransMontaigne Inc.:

We have audited the accompanying consolidated balance sheets of TransMontaigne Inc. and subsidiaries as of June 30, 2003 and 2002, and the related consolidated statements of operations, preferred stock and common stockholders' equity, and cash flows for each of the years in the three-year period ended June 30, 2003. These consolidated financial statements are the responsibility of TransMontaigne's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of TransMontaigne Inc. and subsidiaries as of June 30, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended June 30, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1(c) to the consolidated financial statements, the consolidated statement of operations for the year ended June 30, 2003 has been restated.

As discussed in Note 1(j) to the consolidated financial statements, the Company changed its method of accounting for inventories discretionary volumes in 2003.

Denver, Colorado
September 23, 2003, except as to Notes 1(c) and 1(j) to the consolidated financial statements which are as of February 16, 2004

TransMontaigne Inc. and subsidiaries
Consolidated balance sheets
(In thousands)

	June 30, 2003	June 30, 2002
ASSETS		
Current assets:		
Cash and cash equivalents	$ 27,969	$ 30,852
Restricted cash held by commodity broker	5,155	8,621
Trade accounts receivable, net	277,360	173,736
Inventories discretionary volumes	226,918	175,169
Unrealized gains on derivative contracts	16,817	14,525
Prepaid expenses and other	5,775	2,598
	559,994	405,501
Property, plant and equipment, net	371,735	251,431
Product linefill and tank bottom volumes	22,017	45,298
Unrealized gains on derivative contracts	1,885	8,093
Investments in petroleum related assets	10,131	10,131
Deferred tax assets	482	7,882
Deferred debt issuance costs, net	12,908	2,729
Other assets, net	6,917	4,263
	$ 986,069	$ 735,328
LIABILITIES, PREFERRED STOCK, AND COMMON STOCKHOLDERS' EQUITY		
Current liabilities:		
Commodity margin loan	$ 4,534	$ 11,312
Working capital credit facility	175,000	
Trade accounts payable	144,443	102,780
Unrealized losses on derivative contracts	20,151	8,522
Inventory due to others under exchange agreements	35,121	16,908
Excise taxes payable	86,421	72,045
Other accrued liabilities	25,562	24,242
Deferred revenue supply management services	4,816	1,600
	496,048	237,409
Other liabilities:		
Long-term debt	200,000	187,000
Unrealized losses on derivative contracts	423	209
Total liabilities	696,471	424,618
Preferred stock:		
Series A Convertible Preferred stock		24,421
Series B Redeemable Convertible Preferred stock	79,329	80,939
	79,329	105,360
Common stockholders' equity:		
Common stock	407	399

	June 30, 2003	June 30, 2002
Capital in excess of par value	249,339	245,844
Deferred stock-based compensation	(3,943)	(2,540)
Accumulated deficit	(35,534)	(38,353)
	210,269	205,350
	$ 986,069	$ 735,328

See accompanying notes to consolidated financial statements.

TransMontaigne Inc. and subsidiaries
Consolidated statements of operations
(In thousands, except per share amounts)

	Year ended June 30, 2003	Year ended June 30, 2002	Year ended June 30, 2001
	(As restated)		
Supply, distribution and marketing:			
Revenues	$ 8,241,001	$ 6,001,170	$ 5,182,492
Cost of product sold and other direct costs and expenses	(8,190,918)	(5,932,423)	(5,136,174)
Net operating margins	50,083	68,747	46,318
Terminals, pipelines, and tugs and barges:			
Revenues	82,988	63,386	79,707
Direct operating costs and expenses	(35,196)	(27,668)	(33,817)
Net operating margins	47,792	35,718	45,890
Total net operating margins	97,875	104,465	92,208
Costs and expenses:			
Selling, general and administrative	(40,491)	(35,211)	(34,072)
Depreciation and amortization	(19,371)	(16,556)	(19,510)
Lower of cost or market write-downs on product linefill and tank bottom volumes	(633)	(12,963)	(18,318)
Corporate relocation and transition:			
Severance, transition, and relocation benefits	(1,449)	(2,138)	
Abandonment of office leases and leasehold improvements		(4,178)	
Total costs and expenses	(61,944)	(71,046)	(71,900)

	Year ended June 30, 2003	Year ended June 30, 2002	Year ended June 30, 2001
Operating income	35,931	33,419	20,308
Other income (expenses):			
Dividend income from petroleum related investments	374	1,450	3,060
Interest income	286	599	2,555
Interest expense	(14,705)	(12,436)	(17,770)
Other financing costs:			
Early payment penalty on retirement of long-term debt		(1,943)	(1,277)
Amortization of deferred debt issuance costs	(1,725)	(1,744)	(3,499)
Write-off of debt issuance costs	(5,775)	(2,987)	(3,885)
Gain (loss) on interest rate swap	2,224	(2,322)	(3,634)
Gain (loss) on disposition of assets, net		(13)	22,146
Total other income (expenses)	(19,321)	(19,396)	(2,304)
Earnings before income taxes and cumulative effect of a change in accounting principle	16,610	14,023	18,004
Income tax expense	(8,510)	(5,465)	(6,666)
Earnings before cumulative effect of a change in accounting principle	8,100	8,558	11,338
Cumulative effect of a change in accounting principle of $2,092, net of income tax benefit of $795	(1,297)		
Net earnings	6,803	8,558	11,338
Preferred stock dividends, net	(3,984)	(11,351)	(8,963)
Net earnings (loss) attributable to common stockholders	$ 2,819	$ (2,793)	$ 2,375

TransMontaigne Inc. and subsidiaries
Consolidated statements of operations (continued)
(In thousands, except per share amounts)

	Year ended June 30, 2003	Year ended June 30, 2002	Year ended June 30, 2001
	(As restated)		
Computation of earnings (loss) per share:			
Net earnings (loss) after preferred stock dividends and before cumulative effect of a change in accounting principle	$ 4,116	$ (2,793)	$ 2,375
Cumulative effect of a change in accounting principle	(1,297)		
Net earnings (loss) attributable to common stockholders	$ 2,819	$ (2,793)	$ 2,375

	Year ended June 30, 2003	Year ended June 30, 2002	Year ended June 30, 2001
Basic net earnings (loss) per common share:			
Net earnings (loss) after preferred stock dividends and before cumulative effect of a change in accounting principle	$ 0.10	$ (0.09)	$ 0.08
Cumulative effect of a change in accounting principle	(0.03)		
	$ 0.07	$ (0.09)	$ 0.08
Diluted net earnings (loss) per common share:			
Net earnings (loss) after preferred stock dividends and before cumulative effect of a change in accounting principle	$ 0.10	$ (0.09)	$ 0.08
Cumulative effect of a change in accounting principle	(0.03)		
	$ 0.07	$ (0.09)	$ 0.08
Weighted average common shares outstanding:			
Basic	39,116	31,267	30,879
Diluted	39,263	31,267	31,003

See accompanying notes to consolidated financial statements.

TransMontaigne Inc. and subsidiaries
Consolidated statements of preferred stock and common stockholders' equity
Years ended June 30, 2003, 2002 and 2001
(in thousands)

	Preferred stock						
	Series A	Series B	Common stock	Capital in excess of par value	Deferred stock-based compensation	Accumulated deficit	Total common stockholders' equity
Balance at June 30, 2000	$ 170,115	$	$ 307	$ 201,075	$ (1,465)	$ (37,934)	$ 161,983
Common stock issued for options and warrants exercised			6	1,891			1,897
Net tax effect arising from stock-based compensation				(5)			(5)
Forfeiture of restricted stock awards prior to vesting				(135)	135		
Deferred compensation related to restricted stock awards			5	2,430	(2,435)		
Amortization of deferred stock-based compensation					1,300		1,300
Preferred stock dividends, including $4,710 paid-in-kind	4,710					(8,963)	(8,963)
Net earnings						11,338	11,338
Balance at June 30, 2001	$ 174,825	$	$ 318	$ 205,256	$ (2,465)	$ (35,559)	$ 167,550
Common stock issued for options exercised				151			151

	Preferred stock			Capital in excess of par value	Deferred stock-based compensation		Total common stockholders' equity
Common stock repurchased from employees for withholding taxes				(112)			(112)
Net tax effect arising from stock-based compensation				(24)			(24)
Forfeiture of restricted stock awards prior to vesting			(1)	(501)	502		
Deferred compensation related to restricted stock awards			4	2,085	(2,089)		
Amortization of deferred stock-based compensation					1,512		1,512
Preferred stock dividends paid-in-kind	9,816					(9,816)	(9,816)
Recapitalization of Series A Convertible Preferred stock	(160,220)	80,939	119	59,394		(1,536)	57,977
Common stock repurchased and retired			(41)	(20,405)			(20,446)
Net earnings						8,558	8,558
Balance at June 30, 2002	$ 24,421	$ 80,939	$ 399	$ 245,844	$ (2,540)	$ (38,353)	$ 205,350
Common stock issued for options exercised				12			12
Common stock repurchased from employees for withholding taxes				(214)			(214)
Net tax effect arising from stock-based compensation				70			70
Forfeiture of restricted stock awards prior to vesting				(238)	238		
Deferred compensation related to restricted stock awards			8	3,605	(3,613)		
Deferred compensation related to non-employee stock options				260	(260)		
Amortization of deferred stock-based compensation					2,232		2,232
Preferred stock dividends						(5,594)	(5,594)
Amortization of premium on Series B Redeemable Convertible Preferred stock		(1,610)				1,610	1,610
Repurchase of Series A Convertible Preferred stock	(24,421)						
Net earnings						6,803	6,803
Balance at June 30, 2003	$	$ 79,329	$ 407	$ 249,339	$ (3,943)	$ (35,534)	$ 210,269

See accompanying notes to consolidated financial statements.

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TransMontaigne Inc. and subsidiaries
Consolidated statements of cash flows
(In thousands)

	Year ended June 30, 2003	Year ended June 30, 2002	Year ended June 30, 2001
Cash flows from operating activities:			
Net earnings	$ 6,803	$ 8,558	$ 11,338
Adjustments to reconcile net earnings to net cash provided (used) by operating activities:			
Amortization of deferred revenue	(2,485)	(100)	
Depreciation and amortization	19,371	16,556	19,510

	Year ended June 30, 2003	Year ended June 30, 2002	Year ended June 30, 2001
Deferred tax expense	7,400	5,062	6,224
Net tax effect arising from stock-based compensation	70	(24)	(5)
Loss (gain) on disposition of assets, net		13	(22,146)
Abandonment of office leases and leasehold improvements	(65)	4,178	
Amortization of deferred stock-based compensation	2,232	1,512	1,300
Amortization of debt issuance costs	1,725	1,744	3,499
Repayment of interest rate swap	(3,205)		
Write-off of debt issuance costs	5,775	2,987	3,885
Unrealized loss (gain) on interest rate swap	(2,224)	2,322	3,634
Net change in unrealized (gains)/losses on long-term derivative contracts	6,678	1,716	(13,307)
Lower of cost or market write-downs on base operating inventory volumes	12,435		
Lower of cost or market write-downs on product linefill and tank bottom volumes	633	12,963	18,318
Other		538	93
Changes in operating assets and liabilities, net of effects from acquisitions:			
Trade accounts receivable, net	(103,624)	(94,686)	38,689
Inventories discretionary volumes	(4,599)	(78,182)	67,302
Prepaid expenses and other	(918)	1,533	1,944
Trade accounts payable	40,313	30,609	(34,507)
Unrealized (gain)/loss on derivative contracts	14,782	(1,910)	(14,724)
Inventory due to others under exchange agreements, net	18,213	(59,845)	(48,504)
Excise taxes payable and other accrued liabilities	14,013	42,944	9,393
Net cash provided (used) by operating activities	33,323	(101,512)	51,936
Cash flows from investing activities:			
Acquisition of Coastal Fuels assets	(155,968)		
Acquisition of terminals, pipelines, tugs and barges	(6,983)	(7,115)	
Additions to property, plant and equipment expansion of facilities	(7,170)	(6,503)	(8,197)
Additions to property, plant and equipment maintain existing facilities	(3,649)	(2,191)	(3,345)
Proceeds from sale of assets		120,510	1,439
Decrease (increase) in restricted cash held by commodity broker	3,466	(637)	(7,984)
Decrease (increase) in other assets	(321)	(1,286)	(882)
Net cash provided (used) by investing activities	(170,625)	102,778	(18,969)
Cash flows from financing activities:			
Net borrowings (repayments) of debt	188,000	57,000	(76,995)
Net borrowings (repayments) of commodity margin loan	(6,778)	(8,688)	20,000
Deferred debt issuance costs	(17,679)	(2,791)	(1,779)
Common stock issued for options and warrants exercised	12	151	1,897
Common stock repurchased from employees for withholding taxes	(214)	(112)	
Common stock repurchased and retired		(20,446)	
Cash paid to redeem Series A Convertible Preferred stock	(24,421)	(21,303)	
Preferred stock dividends paid in cash	(4,501)		(4,253)
Net cash provided (used) by financing activities	134,419	3,811	(61,130)

	Year ended June 30, 2003	Year ended June 30, 2002	Year ended June 30, 2001
Increase (decrease) in cash and cash equivalents	(2,883)	5,077	(28,163)
Cash and cash equivalents at beginning of year	30,852	25,775	53,938
Cash and cash equivalents at end of year	$ 27,969	$ 30,852	$ 25,775

TransMontaigne Inc. and subsidiaries
Consolidated statements of cash flows (continued)
(In thousands)

	Year ended June 30, 2003	Year ended June 30, 2002	Year ended June 30, 2001
Supplemental disclosures of cash flow information:			
Cash paid for income taxes	$ 310	$ 600	$ 700
Cash paid for interest expense	$ 13,050	$ 12,240	$ 19,731
Sale of Little Rock facilities on June 30, 2001:			
Proceeds receivable	$	$	$ 29,033
Assets disposed			(6,162)
Liabilities recorded:			
Accrued environmental obligations			(700)
Other			(25)
Gain on disposition			(22,146)
Cash received from sale	$	$ 29,033	$
Sale of West Shore shares on July 27, 2001 and October 29, 2001:			
Investment in West Shore	$	$ (35,952)	$
Loss on disposition		9,896	
Cash received from sale	$	$ 26,056	$
Sale of NORCO system on July 31, 2001:			
Assets disposed	$	$ (49,733)	$
Liabilities recorded upon sale:			
Accrued environmental obligations		(2,000)	
Accrued indemnities		(1,300)	
Other		(116)	
Gain on disposition		(8,601)	
Cash received from sale	$	$ 61,750	$
Sale of ST Oil Company on May 31, 2002:			
Investment in ST Oil Company	$	$ (1,677)	$

	Year ended June 30, 2003	Year ended June 30, 2002	Year ended June 30, 2001
Gain on disposition		(1,363)	
Cash received from sale	$	$ 3,040	$
Other cash sales cash received from sales of other assets	$	$ 631	$ 1,439
Total cash received from sales of assets	$	$ 120,510	$ 1,439

See accompanying notes to consolidated financial statements.

Notes to consolidated financial statements
Years ended June 30, 2003, 2002 and 2001

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation and Use of Estimates

Our accounting and financial reporting policies conform to accounting principles and practices generally accepted in the United States of America. The accompanying consolidated financial statements include the accounts of TransMontaigne Inc. and its majority-owned subsidiaries. All significant inter-company accounts and transactions have been eliminated in consolidation, except for throughput fees, storage fees, pipeline transportation fees, tug and barge fees and other fees charged to our supply, distribution and marketing operations by our terminals, pipelines, and tugs and barges. The related inter-company revenues and costs offset within total net operating margins in the accompanying consolidated statement of operations.

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. The following estimates, in our opinion, are subjective in nature, require the exercise of judgment, and involve complex analysis: allowance for doubtful accounts; fair value of inventories discretionary volumes held for immediate sale or exchange (as of and for periods prior to October 1, 2002); fair value of derivative contracts; prepaid transportation costs; accrued lease abandonment costs; accrued transportation and deficiency obligations; and accrued environmental obligations. Changes in these estimates and assumptions will occur as a result of the passage of time and the occurrence of future events. Actual results could differ from these estimates.

(b) Nature of Business and Basis of Presentation

TransMontaigne Inc., a Delaware corporation ("TransMontaigne") based in Denver, Colorado, was formed in 1995 to create an independent refined petroleum products distribution and supply company. We are a holding company that conducts operations in the United States primarily in the Gulf Coast, Midwest, and East Coast regions. We provide integrated terminal, transportation, storage, supply, distribution, and marketing services to refiners, wholesalers, distributors, marketers, and industrial and commercial end-users of refined petroleum products. Our principal activities consist of (i) terminal, pipeline, and tug and barge operations, (ii) supply, distribution, and marketing, and (iii) supply management services.

On February 28, 2003, we acquired all of the outstanding shares of capital stock of Coastal Fuels Marketing, Inc. and its subsidiary, Coastal Tug and Barge, Inc., from a wholly-owned subsidiary of El Paso Merchant Energy Petroleum Company ("EPME-PC"), along with the rights to and operations of the southeast marketing division of EPME-PC (see Note 2 of Notes to consolidated financial statements).

(c) Restatement of the Adoption of EITF Issue 02-03

Following discussions with the staff of the Securities and Exchange Commission, we have restated our consolidated statement of operations for the year ended June 30, 2003 to report a change in accounting for our inventories base operating volumes effective as of October 1, 2002, as a component of the cumulative effect of a change in accounting principle upon the adoption of EITF Issue 02-03, *Issue Involved in Accounting for derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities* (see Note 1(j) of Notes to consolidated financial statements).

We previously reported that we included in net operating margins attributable to our supply, distribution and marketing activities approximately $18.9 million of margins from the transfer of minimum inventory volumes to discretionary inventory volumes and their subsequent sale to customers during the three months ended March 31, 2003. Of the approximately $18.9 million of margins reported for the three months ended March 31, 2003, approximately $10.6 million of the increase in the value of the inventories base operating inventory volumes was attributable to periods on or before October 1, 2002 and, therefore, that amount, net of related income taxes of approximately $4.0 million, now has been changed to be reported as a component of the cumulative effect of the change in accounting principle upon adoption of EITF 02-03.

The restatement has no impact on the accompanying consolidated balance sheets as of June 30, 2003 and 2002 and the accompanying consolidated statements of cash flows for the years ended June 30, 2003, 2002 and 2001. The effects of the restatement on the accompanying consolidated statement of operations for the year ended June 30, 2003 are as follows:

	Year ended June 30, 2003				
		As previously reported	Adjustment		As restated
Supply, distribution, and marketing net operating margins	$	60,635	(10,552)	$	50,083
Operating income	$	46,483	(10,552)	$	35,931
Earnings before income taxes and cumulative effect of a change in accounting principle	$	27,162	(10,552)	$	16,610
Income tax (expense) benefit	$	(12,520)	4,010	$	(8,510)
Cumulative effect of a change in accounting principle	$	(7,839)	6,542	$	(1,297)
Net earnings (loss)	$	6,803		$	6,803
Net earnings (loss) attributable to common stockholders	$	2,819		$	2,819
Basic net earnings (loss) per common share:					
Net earnings (loss) after preferred stock dividends and before cumulative effect of a change in accounting principle	$	0.27	(0.17)	$	0.10
Cumulative effect of a change in accounting principle		(0.20)	0.17		(0.03)
	$	0.07		$	0.07
Diluted net earnings (loss) per common share:					
Net earnings (loss) after preferred stock dividends and before cumulative effect of a change in accounting principle	$	0.27	(0.17)	$	0.10
Cumulative effect of a change in accounting principle		(0.20)	0.17		(0.03)
	$	0.07		$	0.07

(d) Accounting for Terminal, Pipeline, and Tug and Barge Activities

In connection with our terminal, pipeline, and tug and barge operations, we utilize the accrual method of accounting for revenue and expenses. We generate revenues in our terminal, pipeline, and tug and barge operations from throughput fees, storage fees, transportation fees, ship-assist fees and fees from other ancillary services. Throughput revenue is recognized when the product is delivered to the customer; storage revenue is recognized ratably over the term of the storage contract; transportation revenue is recognized when the product has been delivered to the customer at the specified delivery location; ship-assist revenue is recognized when docking and other services are provided to marine vessels; and other service revenue is recognized as the services are performed.

Shipping and handling costs attributable to our terminal, pipeline, and tug and barge operations are included in direct operating costs and expenses in the accompanying consolidated statement of operations.

(e) Accounting for Supply, Distribution, and Marketing Activities

In our supply, distribution and marketing operations, we purchase refined petroleum products primarily from refineries, schedule them for delivery to our terminals, as well as terminals owned by third parties, and then sell those products to our customers through rack sales, bulk sales, and contract sales. Revenue from our sales of physical inventory are recognized pursuant to the accrual method of accounting (i.e., when cash becomes due and payable to us pursuant to the terms of the sales contracts). Revenue from rack sales and contract sales is recognized when the product is delivered to the customer through a truck loading rack or marine fueling equipment. Revenue from bulk sales is recognized when the title to the product is transferred to the customer, which generally occurs upon confirmation of the terms of the sale.

Shipping and handling costs attributable to our supply, distribution, and marketing operations are included in cost of product sold in the accompanying consolidated statement of operations.

(f) Accounting for Supply Management Services Activities

We provide supply management services to companies and governmental entities that desire to outsource their fuel supply function and to reduce the price volatility associated with their fuel supplies. We offer three types of supply management services: delivered fuel price management, retail price management, and logistical supply management services.

Delivered fuel price management contracts involve the sales of committed quantities of specific motor fuels delivered to our customer's proprietary fleet refueling locations, at fixed prices for terms up to three years. Under retail price management contracts, customers commit for terms up to 18 months to a specific monthly quantity of product within one or more metropolitan areas and agree to a net settlement with us for the difference between a stipulated retail price index and our fixed contract price. Our logistical supply management arrangements permit our customers to use our proprietary web-based inventory management system for a fee, which typically is charged on a per gallon basis.

Revenue from sales made pursuant to delivered fuel price management contracts is recognized when title to the product is transferred to the customer, which generally occurs upon delivery of the product at the customer's proprietary fleet refueling location. Revenue from sales made pursuant to retail price management contracts is recognized when title to the product is transferred to the customer, which generally occurs upon lifting of the product by the customer at the retail gasoline station. Revenue from logistical supply management services fees is recognized on a straight-line basis over the term of the contract.

(g) Accounting for Risk Management Activities

We enter into risk management contracts, principally NYMEX futures contracts, to manage our exposure to changes in commodity prices. We evaluate our market risk exposure from an overall portfolio basis that considers changes in physical inventories discretionary volumes held for

immediate sale or exchange, open positions in derivative contracts, and open positions in risk management contracts. We enter into risk management contracts that offset the changes in the values of our inventories discretionary volumes held for immediate sale or exchange and derivative contracts. At June 30, 2003, our open positions in risk management contracts were NYMEX futures contracts (purchases and sales).

(h) Accounting for Derivative Contracts

Our bulk sales, contract sales, delivered fuel price management, retail price management and risk management contracts qualify as derivative instruments pursuant to the requirements of Statement of Financial Accounting Standards No. 133 ("SFAS No. 133"), *Accounting for Derivative Instruments and Hedging Activities*. All derivative contracts are required to be reported as assets and liabilities at fair value in the accompanying consolidated balance sheet in accordance with SFAS No. 133. The fair value of our derivative contracts is included in "Unrealized gains or losses on derivative contracts" in the accompanying consolidated balance sheet. At June 30, 2003 and 2002, there were no unrealized gains or losses on risk management contracts because NYMEX futures contracts require daily settlement for changes in commodity prices on open futures contracts. Changes in the fair value of our derivative contracts are included in net operating margins attributable to our supply, distribution and marketing operations.

Effective April 1, 2002, the estimated fair value of our delivered fuel price management and retail price management contracts at origination is deferred because our estimate of the fair value is not evidenced by quoted market prices or current market transactions for the contracts in their entirety. The deferred revenue is amortized into income over the respective terms of the contracts as the products are delivered to the ground fleet customers. Subsequent changes in the fair value of our delivered fuel price management and retail price management contracts are included in net operating margins attributable to our supply, distribution, and marketing operations.

(i) Presentation of Revenues from Energy-Related and Risk Management Activities

Pursuant to the consensus on EITF Issue No. 02-03 ("EITF 02-03"), *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, gains and losses (realized and unrealized) on derivative contracts that are held for trading purposes are presented net in the accompanying consolidated statement of operations whether or not the contracts are settled physically (i.e., product costs are required to be netted directly against gross revenues to arrive at net revenues). Gains and losses on other energy-related contracts that settle physically are presented on a gross basis, whereas, gains and losses on other energy-related contracts that settle on a net cash basis are presented on a net basis in the accompanying consolidated statement of operations.

We present revenue from our rack sales, bulk sales, contract sales, and delivered fuel price management on a gross basis in the accompanying consolidated statement of operations; whereas, gains and losses on retail price management contracts and risk management contracts are presented on a net basis in the accompanying consolidated statement of operations. The logistical supply management services fees do not involve the sale of inventory and, therefore, only the service fee is presented in the accompanying consolidated statement of operations.

(j) Accounting for Inventories Discretionary Volumes

Our inventories discretionary volumes consist of refined petroleum products, primarily gasolines, distillates, and No. 6 oil. At June 30, 2003, our inventories discretionary volumes are composed of volumes held for immediate sale or exchange and volumes held for base operations. Volumes held for immediate sale or exchange generally are subject to price risk management activities. Volumes held for base operations generally are not subject to price risk management activities. Inventories discretionary volumes are presented in the accompanying consolidated balance sheet as current assets and are carried at the lower of cost (first-in, first-out) or market (replacement cost) for periods subsequent to September 30, 2002. Prior to October 1, 2002, our inventories discretionary volumes held for immediate sale or exchange were carried at fair value and our volumes held for base operations, representing minimum volumes in-transit in common carrier pipelines, were carried at original cost adjusted for impairment write-downs (see Note 1(k) of Notes to consolidated financial statements). Inventories discretionary volumes are as follows (in thousands):

	June 30, 2003		June 30, 2002	
	Amount	Bbls	Amount	Bbls
Volumes held for immediate sale or exchange	$ 130,492	3,890	$ 175,169	5,749
Volumes held for base operations	96,426	2,922		
Inventories discretionary volumes	$ 226,918	6,812	$ 175,169	5,749

At June 30, 2003, the market value of our volumes held for immediate sale or exchange exceeded their cost basis by approximately $5.9 million. During the year ended June 30, 2003, we recognized an impairment loss of approximately $12.4 million due to lower of cost or market write-downs on our base operating inventory volumes.

Through September 30, 2002 we marked to market our energy trading and risk management activities pursuant to the guidance in Issue No. 98-10 ("EITF 98-10"), *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. The mark-to-market method of accounting requires that the effect of changes in the fair value of our energy trading and risk management activities be recognized as assets and liability and included in net operating margins attributable to supply, distribution, and marketing in the period of the change in value. On

October 25, 2002, the Emerging Issues Task Force reached a consensus on Issue No. 02-03 ("EITF 02-03"), *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, that eliminated mark-to-market accounting for energy trading and risk management activities that are not derivative contracts. EITF 02-03 also concluded that all physical inventories, including inventory volumes associated with energy trading activities, be carried at the lower of cost or market pursuant to Accounting Research Bulletin ("ARB") No. 43, *Chapter 4 Inventory Pricing*. As a result, we are no longer permitted to carry our inventories discretionary volumes held for immediate sale or exchange at fair value effective October 1, 2002.

During the year ended June 30, 2003, we adjusted the carrying amount of our inventories discretionary volumes to the lower of cost (first-in, first-out) or market pursuant to the requirements of EITF 02-03 through a cumulative effect adjustment for a change in accounting principle. The

cumulative effect adjustment is presented in the accompanying consolidated statement of operations and is calculated as follows (in thousands):

Inventories discretionary volumes:

Volumes held for immediate sale or exchange:		
Fair value at October 1, 2002	$	(180,241)
Cost basis at October 1, 2002		167,597
Excess of fair value over cost basis		(12,644)
Base operating volumes:		
Original cost basis original cost as adjusted at October 1, 2002		(28,959)
New cost basis first-in, first-out at October 1, 2002		39,511
Excess of new cost basis over original cost basis		10,552
Change in carrying amount of inventories discretionary volumes		(2,092)
Income tax effects at 38%		795
Cumulative effect of a change in accounting principle	$	(1,297)

We enter into exchange agreements with major oil companies. Exchange agreements generally are fixed term agreements that involve our receipt of a specified volume of product at one location in exchange for delivery by us of product at a different location. At June 30, 2003 and 2002, current liabilities include inventory due to others under exchange agreements of approximately 1.0 million barrels and 0.5 million barrels, respectively, with a fair value of approximately $35.1 million and $16.9 million, respectively. The amount recorded represents the fair value of inventory due to others under exchange agreements at the balance sheet date.

(k) Accounting for Product Linefill and Tank Bottom Volumes

Our product linefill and tank bottom volumes are required to be held for operating balances in the conduct of our overall operating activities. We do not intend to sell or exchange these volumes in the ordinary course of business and, therefore, we do not hedge the market risks associated with these volumes.

At June 30, 2003, our product linefill and tank bottom volumes consist of refined products held in our proprietary pipelines and tank bottoms. At June 30, 2002, our product linefill and tank bottom volumes consisted of tank bottoms, linefill in our proprietary pipelines, and in-transit volumes on common carrier pipelines. Product linefill and tank bottom volumes are as follows (in thousands):

	June 30, 2003		June 30, 2002	
	Amount	**Bbls**	**Amount**	**Bbls**

	June 30, 2003		June 30, 2002	
Volumes held for base operations	$		$ 28,959	1,280
Linefill and tank bottom volumes	22,017	877	16,339	720
	$ 22,017	877	$ 45,298	2,000

Prior to October 1, 2002, our product linefill and tank bottom volumes aggregated approximately 2.0 million barrels of product reflecting tank bottoms, line fill in our proprietary pipelines, and in-transit volumes on common carrier pipelines. On October 1, 2002, in connection with the adoption of EITF 02-03, we transferred to inventories discretionary volumes approximately 1.3 million barrels of product linefill and tank bottom volumes representing the volumes associated with our in-transit

volumes on common carrier pipelines. As of June 30, 2003, we have approximately 877,000 barrels of product reflecting tank bottoms and line fill in our proprietary pipelines.

At June 30, 2003 and 2002, our product linefill and tank bottom volumes are presented in the accompanying consolidated balance sheet as non-current assets and are carried at the lower of cost (weighted average) or market (replacement cost). The replacement cost of our product linefill and tank bottom volumes is based on the nearest quoted wholesale market price. Product linefill and tank bottom volumes consist of the following (in thousands):

	June 30, 2003		June 30, 2002	
	Amount	**Bbls**	**Amount**	**Bbls**
Gasolines	$ 13,020	497	$ 27,855	1,200
Distillates	7,449	319	17,443	800
No. 6 oil	1,548	61		
Product linefill and tank bottom volumes	$ 22,017	877	$ 45,298	2,000

At June 30, 2003 and 2002, the weighted average adjusted cost basis of our product linefill and tank bottom volumes was approximately $0.60 and $0.54 per gallon, respectively. During the years ended June 30, 2003, 2002 and 2001, we recognized impairment losses of approximately $0.6 million, $13.0 million and $18.3 million, respectively, due to lower of cost or market write-downs on our product linefill and tank bottom volumes.

(l) Cash and Cash Equivalents

We consider all short-term investments with a remaining maturity of three months or less at the date of purchase to be cash equivalents.

Restricted cash represents cash deposits held by our commodity broker to cover initial margin requirements related to open NYMEX futures contracts.

(m) Property, Plant and Equipment

Depreciation is computed using the straight-line and double-declining balance methods. Estimated useful lives are 20 to 25 years for plant, which includes buildings, storage tanks, and pipelines, and 3 to 20 years for equipment. All items of property, plant and equipment are carried at cost. Expenditures that increase capacity, or extend useful lives are capitalized. Routine repairs and maintenance are expensed.

We expense as incurred the costs related to the planning and preliminary project stage of our internal-use software and website development efforts. Direct costs incurred in the development stage are capitalized as property, plant and equipment and amortized over their estimated useful lives not to exceed five years as depreciation and amortization expense. The costs of installing certain enterprise-wide information systems are amortized over periods not exceeding 10 years. Costs associated with minor upgrades, enhancements and maintenance are expensed as incurred and included in selling, general and administrative expenses in the accompanying consolidated statement of operations.

We evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable based on expected undiscounted cash flows

attributable to that asset. If an asset is impaired, the impairment loss to be recognized is the excess of the carrying amount of the asset over its estimated fair value.

(n) Deferred Debt Issuance Costs

Deferred debt issuance costs are amortized using the interest method over the term of the underlying debt instrument. Deferred debt issuance costs are as follows (in thousands):

	June 30, 2002	Additions	Amortization	Write-off of debt issuance costs	June 30, 2003
Working capital credit facility	$	$ 6,659	$ (718)	$	$ 5,941
Senior secured term loan		3,892	(305)	(3,587)	
Senior subordinated notes		7,051	(84)		6,967
Former bank credit facility	2,729	77	(618)	(2,188)	
	$ 2,729	$ 17,679	$ (1,725)	$ (5,775)	$ 12,908

(o) Environmental Obligations

We accrue for environmental costs that relate to existing conditions caused by past operations when estimable. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as fines, damages and other costs, including direct internal and legal costs. Liabilities for environmental costs at a specific site are initially recorded, on an undiscounted basis, when it is probable that we will be liable for such costs, and a reasonable estimate of the associated costs can be made based on available information. Such an estimate includes our share of the liability for each specific site and the sharing of the amounts related to each site that will not be paid by other potentially responsible parties, based on enacted laws and adopted/regulations and policies. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation, technology changes, alternatives available and the evolving nature of environmental laws and regulations. We periodically file claims for insurance recoveries of certain environmental remediation costs with our insurance carriers under our comprehensive liability policies. Due to the uncertainty of obtaining recoveries from our insurance carriers, we recognize our insurance recoveries as a credit to income in the period the insurance recoveries are received.

At June 30, 2003 and 2002, we have accrued environmental obligations of approximately $5.6 million and $2.3 million, respectively, representing our best estimate of our remediation obligations (see Note 9 of Notes to consolidated financial statements). During the years ended June 30, 2003 and 2002, we made payments of approximately $0.4 million and $0.4 million, respectively, towards our environmental remediation obligations. During the year ended June 30, 2003 we charged to income approximately $0.8 million to increase our estimate of our future environmental remediation obligations. During the years ended June 30, 2003, 2002 and 2001, we received insurance recoveries of approximately $0.5 million, $1.8 million and $1.6 million, respectively.

(p) Income Taxes

We utilize the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply in the years in which these temporary differences are expected to be recovered or settled. Changes in tax rates are recognized in income in the period that includes the enactment date.

(q) Equity-Based Compensation Plans

We account for our employee stock option plans and restricted stock awards using the intrinsic value method pursuant to APB Opinion No. 25, *Accounting for Stock Issued to Employees*. We recognize deferred compensation on the date of grant if the quoted market price of the underlying common stock exceeds the exercise price (zero exercise price in the case of an award of restricted common stock). Accordingly, no compensation cost has been recognized for the granting of stock options to employees because the exercise price was equal to the quoted market price of the underlying common stock on the date of grant. If compensation cost for our stock-based compensation plans had been determined based on the fair value at the grant dates for awards under those plans pursuant to SFAS 123, *Accounting for Stock-Based Compensation,* our net earnings and earnings per common share would have been reduced to the pro forma amounts indicated below (in thousands, except for per share amounts):

	Years ended June 30,		
	2003	**2002**	**2001**
Net earnings (loss) attributable to common stockholders:			
As reported	$ 2,819	$ (2,793)	$ 2,375
Amortization of the fair value of stock options granted to employees	(379)	(491)	(126)
Pro forma	$ 2,440	$ (3,284)	$ 2,249
Earnings (loss) per common share			
As reported			
Basic	$ 0.07	$ (0.09)	$ 0.08
Diluted	$ 0.07	$ (0.09)	$ 0.08
Pro forma			
Basic	$ 0.06	$ (0.11)	$ 0.07
Diluted	$ 0.06	$ (0.11)	$ 0.07

There were no options granted during the year ended June 20, 2003. The weighted average fair value at grant dates for options granted during the years ended June 30, 2002 and 2001 was $3.08 and $2.12, respectively. The primary assumptions used to estimate the fair value of options granted on the date of grant using the Black-Scholes option-pricing model during the years ended June 30, 2002 and 2001 were as follows: no dividend yield, expected volatility of 79% and 61%, risk-free rates of 4.49% and 4.95%, and expected lives of 4 years, and 5 years, respectively.

Deferred compensation is amortized to income over the related vesting period on an accelerated basis pursuant to FASB Interpretation No. 28.

(r) Earnings (Loss) Per Common Share

Basic earnings (loss) per common share is calculated based on the weighted average number of common shares outstanding during the period, excluding restricted common stock subject to continuing vesting requirements. Diluted earnings (loss) per share is calculated based on the weighted average number of common shares outstanding during the period and, when dilutive, potential common shares from the exercise of stock options and warrants to purchase common stock and restricted common stock subject to continuing vesting requirements pursuant to the treasury stock method. Diluted earnings (loss) per share also gives effect, when dilutive, to the conversion of the preferred stock pursuant to the if-converted method.

(s) Adoption of New Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*, which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for other than the carrying amount of the liability, a gain or loss is recognized on settlement. We adopted the provisions of SFAS No. 143 effective July 1, 2002. In connection with the adoption of SFAS No. 143, we reviewed current laws and regulations governing obligations for asset retirements. Based on that review we did not identify any significant legal obligations associated with the retirement of our tangible long-lived assets. Therefore, the adoption of SFAS No. 143 did not have an impact on our consolidated financial statements.

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which addresses the financial accounting and reporting for long-lived assets to be disposed of by sale and broadens the presentation of discontinued operations to include more disposal transactions. SFAS No. 144 also provides guidance that will eliminate inconsistencies in accounting for the impairment or disposal of long-lived assets under existing accounting pronouncements. We adopted the provisions of SFAS No. 144 effective July 1, 2002. The adoption of SFAS No. 144 did not have an impact on our consolidated financial statements.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123 ("SFAS No. 123")*, which addresses 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 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 adopted the disclosure provisions of SFAS No. 148.

(2) ACQUISITIONS

On February 28, 2003, we acquired all of the outstanding shares of capital stock of Coastal Fuels Marketing, Inc. and its subsidiary, Coastal Tug and Barge, Inc., from El Paso CGP Company ("CGP")

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along with the rights to and operations of the southeast marketing division of El Paso Merchant Energy Petroleum Company ("EPME-PC"). The acquisition included five Florida terminals, with aggregate capacity of approximately 4.9 million barrels, and a related tug and barge operation (collectively, the "Coastal Fuels assets"). The Coastal Fuels assets primarily provide sales and storage of bunker fuel, No. 6 oil, diesel fuel and gasoline at Cape Canaveral, Port Manatee/Tampa, Port Everglades/Ft. Lauderdale and Fisher Island/Miami, and storage of asphalt at Jacksonville, Florida. The purchase price for the acquisition was approximately $156.0 million, including approximately $37.0 million of product inventory. The consolidated financial statements include the results of operations of the Coastal Fuels assets from the closing date of the transaction (February 28, 2003).

On January 31, 2003, we acquired for cash consideration of approximately $6.4 million a 500,000-barrel products terminal in Fairfax, Virginia. The terminal supplies product to the Washington, D.C. market and increases our presence in the Mid-Atlantic market.

On July 31, 2002, we acquired for cash consideration of approximately $0.6 million a products terminal in Brownsville, Texas. The 25,000-barrel terminal provides us with additional storage and rail car handling facilities in Brownsville, Texas.

Effective June 30, 2002, we acquired for cash consideration of approximately $7.2 million the remaining 40% interest that we previously did not own in the Razorback Pipeline system ("Razorback"), a 67 mile petroleum products pipeline between Mount Vernon, Missouri and Rogers, Arkansas with approximately 0.4 million barrels of storage capacity. We accounted for the step-acquisition of Razorback using the purchase method of accounting as of the effective date of the transaction.

The purchase price of each transaction was allocated to the assets and liabilities acquired based upon the estimated fair value of the assets and liabilities as of the acquisition date. The purchase price was allocated as follows (in thousands):

	Coastal Fuels	Fairfax	Brownsville	Razorback
Discretionary inventory volumes	$ 30,625	$	$	$

	Coastal Fuels	Fairfax	Brownsville	Razorback
Prepaid expenses and other current assets	2,259			2
Property, plant and equipment	121,287	6,773	630	7,188
Other assets acquired intangible	2,500			
Product linefill and tank bottom volumes	6,311			
Trade accounts payable due diligence costs	(1,350)			
Acquisition related liabilities	(5,664)	(420)		(75)
Cash paid, net of cash acquired of $0, $0, $0 and $85, respectively	$ 155,968	$ 6,353	$ 630	$ 7,115

At June 30, 2003, the allocation of the purchase price to the Coastal Fuels assets is preliminary. We are awaiting the completion of certain environmental analyses to more accurately estimate the costs of remediation activities associated with the acquired properties. Coastal Fuels acquisition related liabilities of approximately $5.7 million represent an estimate of the fair value of certain assumed obligations that existed at the date of the Coastal Fuels assets acquisition, including estimated environmental remediation costs of approximately $2.5 million, estimated litigation costs of approximately $2.9 million, lease abandonment costs of approximately $130,000 and property taxes of approximately $140,000. Fairfax acquisition related liabilities include approximately $0.4 million of estimated environmental remediation costs.

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The unaudited pro forma combined results of operations as if the acquisition of the Coastal Fuels assets and the step-acquisition of Razorback had occurred on July 1, 2001 are as follows (in thousands, except per share data):

	Year ended June 30, 2003	Year ended June 30, 2002
	(unaudited)	
Revenue	$ 8,758,555	$ 6,489,196
Net earnings	$ 12,196	$ 9,991
Basic earnings (loss) per share	$ 0.21	$ (0.04)

(3) DISPOSITIONS

On July 31, 2001, we sold the NORCO Pipeline system and related terminals ("NORCO") for cash consideration of approximately $62.0 million and recognized a net gain of approximately $8.6 million on the sale. For the month ended July 31, 2001, we recognized net revenues of approximately $1.3 million, direct operating costs and expenses of approximately $0.6 million, and depreciation and amortization expense of approximately $0.3 million related to the operations of the NORCO system. For the year ended June 30, 2001, we recognized revenues of approximately $16.5 million, direct operating costs and expenses of approximately $9.9 million, and depreciation and amortization expense of approximately $3.0 million related to the operations of the NORCO system.

Effective June 30, 2001, we sold two petroleum distribution facilities in Little Rock, Arkansas for $29.0 million. The cash proceeds from the sale transaction were received on July 3, 2001. We recognized a net gain in June 2001 of approximately $22.1 million on the sale. For the year ended June 30, 2001, we recognized revenues of approximately $4.7 million, direct operating costs and expenses of approximately $0.9 million, and depreciation and amortization expense of approximately $0.4 million.

On July 27, 2001, we sold a portion of our investment in the common stock of West Shore Pipeline Company ("West Shore") for cash consideration of approximately $2.9 million. We recognized a net loss of approximately $1.1 million on this sale. We also recognized an impairment loss on our remaining investment in West Shore of approximately $8.8 million. On October 29, 2001, we sold our remaining investment in West Shore for cash consideration of approximately $23.1 million, which approximated our adjusted cost basis. For the years ended June 30, 2002 and 2001, we recognized $0.7 million and $2.2 million of dividend income from West Shore, respectively.

On May 31, 2002, our investment in ST Oil Company was reacquired by ST Oil Company for cash consideration of approximately $3.0 million, resulting in a net gain of approximately $1.4 million on the sale. For each of the years ended June 30, 2002 and 2001, we recorded equity in earnings from our investment in ST Oil Company of less than $0.1 million.

(4) CONCENTRATION OF CREDIT RISK AND TRADE ACCOUNTS RECEIVABLE

Our primary market areas are located in the Northeast, Midwest and Southeast regions of the United States. We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies, other wholesalers, waste management companies and transportation companies. These concentrations of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. Our customers' historical and future credit positions are analyzed prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions we may request letters of credit, prepayments or guarantees. We maintain allowances for potentially uncollectible accounts receivable. During the years ended June 30, 2003, 2002 and 2001, we increased the allowance for doubtful accounts through a charge to income of approximately $0.7 million, $0.2 million and $0.5 million, respectively.

Trade accounts receivable, net consists of the following (in thousands):

	June 30, 2003	June 30, 2002
Trade accounts receivable	$ 279,282	$ 174,986
Less allowance for doubtful accounts	(1,922)	(1,250)
	$ 277,360	$ 173,736

No single customer accounted for 10% or more of total revenues for the years ended June 30, 2003, 2002 or 2001.

(5) UNREALIZED GAINS AND LOSSES ON DERIVATIVE CONTRACTS

Unrealized gains and losses on derivative contracts are as follows (in thousands):

	June 30, 2003	June 30, 2002
Unrealized gains current	$ 16,817	$ 14,525
Unrealized gains long-term	1,885	8,093
Unrealized gains asset	18,702	22,618
Unrealized losses current	(20,151)	(8,522)
Unrealized losses long-term	(423)	(209)
Unrealized losses liability	(20,574)	(8,731)
Net asset (liability) position	$ (1,872)	$ 13,887

At June 30, 2003 and 2002, there were no unrealized gains or losses on risk management contracts because NYMEX futures contracts require daily settlement for changes in commodity prices on open futures contracts.

(6) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment, net is as follows (in thousands):

	June 30, 2003	June 30, 2002
Land	$ 46,477	$ 14,125
Terminals, pipelines and equipment	365,379	276,559
Technology and equipment	13,426	12,645
Tugs and barges	15,914	
Furniture, fixtures and equipment	6,539	5,732
Construction in progress	4,125	3,291
	451,860	312,352
Less accumulated depreciation	(80,125)	(60,921)
	$ 371,735	$ 251,431

(7) INVESTMENT IN PETROLEUM RELATED ASSETS

We own 18.04% of the common stock of Lion Oil Company ("Lion"), an Arkansas-based refinery. For financial reporting purposes, we carry our investment in Lion at the lower of cost or net realizable value. At June 30, 2003 and 2002, the carrying amount of our investment in Lion is approximately $10.1 million. For the years ended June 30, 2003, 2002, and 2001, we recorded dividend income from Lion of approximately $0.4 million, $0.7 million, and $0.8 million, respectively.

(8) OTHER ASSETS

Other assets are as follows (in thousands):

	June 30, 2003	June 30, 2002
Prepaid transportation	$ 3,021	$ 2,644
Acquired intangible, net of accumulated amortization of $167	2,333	
Commodity trading membership	1,500	1,500
Deposits and other assets	63	119
	$ 6,917	$ 4,263

Prepaid transportation relates to our contractual transportation and deficiency agreements with three interstate product pipelines (see Note 17 of Notes to consolidated financial statements).

Acquired intangible represents the right to use the Coastal Fuels trade name for a period of five years. The cost of the acquired intangible is being amortized on a straight-line basis over five years.

Commodity trading membership represents the purchase price we paid to acquire two seats on the NYMEX.

(9) ACCRUED LIABILITIES

Accrued liabilities are as follows (in thousands):

	June 30, 2003	June 30, 2002
Interest rate swap, at fair value	$	$ 5,429
Accrued environmental obligations	5,577	2,329
Accrued corporate relocation and transition		2,029
Accrued lease abandonment	3,178	3,110
Accrued indemnities NORCO	1,300	1,300
Accrued transportation and deficiency obligations	2,013	2,839
Dividend payable preferred stock	1,093	
Accrued expenses and other	12,401	7,206
	$ 25,562	$ 24,242

Interest Rate Swap. We had a $150 million notional value "periodic knock-out" swap agreement with a money center bank to offset the exposure of an increase in interest rates. The interest rate swap was carried at fair value in the accompanying consolidated balance sheets as it did not qualify as an accounting hedge for financial reporting purposes. On February 28, 2003, we settled our obligations under the interest rate swap for approximately $3.2 million when we repaid our former bank credit facility. Included in interest (expense) income for the years ended June 30, 2003, 2002 and 2001, are net (payments) receipts we (incurred) received under the interest rate swap of approximately $(3.9) million, $(4.6) million and $0.7 million, respectively.

Accrued Corporate Relocation and Transition. During the year ended June 30, 2002, we announced to our employees that our supply, distribution, and marketing operations in Atlanta, Georgia would be relocated to Denver, Colorado. On March 19, 2002, we offered approximately 72 employees the opportunity to relocate to Denver, Colorado and we informed approximately 25 employees that they would not be offered the opportunity to relocate to Denver, Colorado. Ultimately, 35 employees chose to relocate to Denver, Colorado. Those employees received a transition bonus and a relocation package payable upon their transfer to the Denver office. The transition bonus was accrued over the period from the date of acceptance by the employee to their date of arrival in Denver, Colorado. The relocation costs were accrued as incurred or earned by the employee. Ultimately, 37 employees chose not to relocate and those employees received special termination benefits upon their termination date as determined by us. The special termination benefits were accrued upon receipt of the notification from the employee that they did not intend to accept the offer to relocate to Denver, Colorado. During the year ended June 30, 2003, we completed our employee relocation program.

(in thousands)	Accrued liability at June 30, 2002	Amounts incurred/accrued during the period	Amounts paid during the period	Accrued liability at June 30, 2003
Accrued special termination benefits to employees not relocating to Denver, Colorado	$ 1,428	$	$ (1,428)	$
Accrued transition benefits payable to employees relocating to Denver, Colorado	501	225	(726)	
Relocation costs incurred during the period	100	1,224	(1,324)	
	$ 2,029	$ 1,449	$ (3,478)	$

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Accrued Lease Abandonment. In connection with our corporate relocation and transition, we entered into an operating lease for new office space in Denver, Colorado. The new lease was executed on April 19, 2002. We vacated our existing office space in Denver, Colorado during June 2003 and we vacated our excess space in Atlanta, Georgia during October 2002. In connection with our acquisition of the Coastal Fuels assets, we vacated a sales office in Coral Gables, Florida (see Note 2 of Notes to consolidated financial statements). The accrual for the abandonment of the office leases represents the excess of the remaining lease payments subsequent to vacancy of the space by us over the estimated sublease rentals to be received based on current market conditions. At June 30, 2003 and 2002, the accrued liability for lease abandonment costs was approximately $3.2 million and $3.1 million, respectively.

(in thousands)	Accrued liability at June 30, 2002	Change in estimate charged to expense	Acquisition related liability assumed	Amounts paid during the period	Accrued liability at June 30, 2003
Accrued lease abandonment	$ 3,110	$ 223	$ 133	$ (288)	$ 3,178

We expect to pay the accrued liability of approximately $3.2 million, net of estimated sublease rentals, as follows (in thousands):

Years ending June 30:	Lease payments	Estimated sublease rentals	Accrued liability
2004	$ 1,432	$ (278)	$ 1,154
2005	1,075	(577)	498
2006	1,097	(577)	520
2007	928	(480)	448
2008	370	(187)	183
Thereafter	763	(388)	375
	$ 5,665	$ (2,487)	$ 3,178

(10) DEFERRED REVENUE SUPPLY MANAGEMENT SERVICES

In connection with providing delivered fuel price management to ground fleet customers, we commit to provide our customers with logistical supply management services over the term of their respective supply contracts. At June 30, 2003 and 2002, our deferred revenue associated with logistical supply management services was approximately $1.0 million and $1.6 million, respectively. We amortize the deferred revenue from these contracts into revenues attributable to our supply, distribution, and marketing operations over the respective terms of the contracts as the products are delivered to the ground fleet customers. During the years ended June 30, 2003 and 2002, we recognized approximately $600,000 and $100,000, respectively, in revenues attributable to our supply, distribution and marketing operations from the amortization of these contracts.

We enter into price management contracts with ground fleet customers that permit these customers to fix the price of their fuel purchases. During the year ended June 30, 2003, we originated retail price management contracts and delivered fuel price management contracts with estimated fair values of approximately $2.9 million and $2.8 million, respectively, representing the excess of the amounts we expect to receive from the ground fleet customers over our estimate of the forward price curve of the underlying commodity adjusted for basis differentials. We have deferred the estimated fair value of

these contracts at origination because our estimate of the fair value is not evidenced by quoted market prices or current market transactions for the contracts in their entirety. We amortize the deferred revenue from these contracts into revenues attributable to our supply, distribution, and marketing operations over the respective terms of the contracts as the products are delivered to the ground fleet customers. During the year ended June 30, 2003, we recognized approximately $1.9 million in revenues attributable to our supply, distribution and marketing operations from the amortization of the deferred revenue from these contracts.

(in thousands)	Deferred revenue at June 30, 2002	Additions during the period	Amounts amortized during the period	Deferred revenue at June 30, 2003
Logistical supply management services	$ 1,600	$	$ (600)	$ 1,000
Retail price management contracts		2,909	(862)	2,047
Delivered fuel price management contracts		2,792	(1,023)	1,769

(in thousands)	Deferred revenue at June 30, 2002	Additions during the period	Amounts amortized during the period	Deferred revenue at June 30, 2003
	$ 1,600	$ 5,701	$ (2,485)	$ 4,816

(11) DEBT

Debt is as follows (in thousands):

	June 30, 2003	June 30, 2002
Commodity margin loan	$ 4,534	$ 11,312
Working capital credit facility	175,000	
Senior subordinated notes	200,000	
Former bank credit facility		187,000
	379,534	198,312
Less debt classified as current	(179,534)	(11,312)
Long-term debt	$ 200,000	$ 187,000

Commodity Margin Loan. We currently have a commodity margin loan agreement with Salomon Smith Barney that allows us to borrow up to $20.0 million to fund certain initial and variation margin requirements in commodities accounts maintained by us with Salomon Smith Barney. The entire unpaid principal amount of the loan, together with accrued interest, is due and payable on demand. Outstanding loans bear interest at the average 90-day Treasury Bill rate plus 1.75% (2.63% at June 30, 2003).

Former Bank Credit Facility. On February 28, 2003 we repaid in full our former bank credit facility. Our former bank credit facility consisted of a $300.0 million revolving credit facility that was scheduled to mature on June 27, 2005. During the year ended June 30, 2003, we wrote-off the unamortized deferred debt issuance costs of approximately $2.2 million associated with the repayment of our former bank credit facility.

New Credit Agreement. On February 28, 2003, we executed a Credit Agreement with UBS AG that initially provided for a $250 million revolving line of credit ("Working Capital Credit Facility") and a $200 million senior secured term loan ("Term Loan"). In connection with the new Credit Agreement, we incurred approximately $10.6 million in costs to execute the financing. The costs are comprised of: $5.6 million in fees paid to UBS AG for the Working Capital Credit Facility, $3.5 million in net fees

paid to UBS AG for the Term Loan, and $1.5 million paid to legal advisers to draft the Credit Agreement.

Working Capital Credit Facility. The Working Capital Credit Facility currently provides for a maximum borrowing line of credit that is the lesser of (i) $275 million and (ii) the borrowing base (as defined; $350 million at June 30, 2003). The maximum borrowing amount is reduced by the amount of letters of credit that are outstanding ($4.9 million at June 30, 2003). Borrowings under the Working Capital Credit Facility bear interest (at our option) based on a base rate plus a specified margin, or LIBOR plus a specified margin; the specified margins are a function of our leverage ratio (as defined). Accrued interest on the outstanding borrowings is due monthly. The weighted average interest rate on borrowings under the Working Capital Credit Facility was 3.9% through June 30, 2003. Borrowings under the Working Capital Credit Facility are secured by substantially all of our current assets. The terms of the Working Capital Credit Facility include financial covenants relating to fixed charge coverage, current ratio, consolidated tangible net worth, capital expenditures, cash distributions and open inventory positions that are tested on a quarterly and annual basis. As of June 30, 2003, we were in compliance with all covenants included in the Working Capital Credit Facility. The Working Capital Credit Facility matures February 28, 2006. In the accompanying consolidated balance sheet at June 30, 2003, we have classified the outstanding borrowings under the Working Capital Credit Facility as a current liability because we have pledged our current assets as security for the facility and because currently it is our expectation that we will repay the outstanding borrowings within one year of the balance sheet date.

Senior Secured Term Loan. The Term Loan provided for a one-time borrowing of $200 million with a scheduled maturity of February 28, 2006. The proceeds from the Term Loan were used primarily to finance the acquisition of the Coastal Fuels assets. The Term Loan was repaid in full on May 30, 2003 with the proceeds from the Senior Subordinated Notes. During the year ended June 30, 2003, we wrote-off the unamortized deferred debt issuance costs of approximately $3.6 million associated with the repayment of the Term Loan.

Senior Subordinated Notes. On May 30, 2003, we consummated the sale and issuance of $200 million aggregate principal amount of $9^1/_8$% Senior Subordinated Notes due 2010 and received proceeds of $194.5 million (net of underwriters' discounts of $5.5 million). The Senior Subordinated Notes mature on June 1, 2010 and interest is payable semi-annually in arrears on each June 1 and December 1 commencing on December 1, 2003. The Senior Subordinated Notes are unsecured and subordinated to all of our existing and future senior debt. Upon certain change of control events, each holder of the Senior Subordinated Notes may require us to repurchase all or a portion of its notes at a purchase price equal to 101% of the principal amount thereof, plus accrued interest. The indenture governing the Senior Subordinated Notes contains covenants that, among other things, limit our ability to incur additional indebtedness, pay dividends on, redeem or repurchase our common stock, make investments, make certain dispositions of assets, engage in transactions with affiliates, create certain liens, and consolidate, merge, or transfer all or substantially all of our assets. The Senior Subordinated Notes are fully and unconditionally guaranteed on a joint and several basis by our subsidiaries other than minor subsidiaries that are inactive and have no assets or operations. We are a holding company for our subsidiaries, with no independent assets or operations. Accordingly, we are dependent upon the distribution of the earnings of our subsidiaries, whether in the form of dividends, advances or payments on account of inter-company obligations, to service our debt obligations. There are no restrictions on our ability or any subsidiary guarantor to obtain funds from our subsidiaries.

Scheduled maturities of debt at June 30, 2003 are as follows (in thousands):

Years ending:

June 30, 2004	$	4,534
June 30, 2005		
June 30, 2006		175,000
June 30, 2007		
June 30, 2008		
Thereafter		200,000
	$	379,534

(12) PREFERRED STOCK

At June 30, 2003 and 2002, we have authorized the issuance of up to 2,000,000 shares of preferred stock. Preferred stock is as follows (in thousands, except share data):

	June 30, 2003		June 30, 2002	
Series A Convertible Preferred stock, par value $0.01 per share, 250,000 shares authorized, 24,421 shares issued and outstanding, liquidation preference of $24,421	$		$	24,421
Series B Redeemable Convertible Preferred stock, par value $0.01 per share, 100,000 shares authorized, 72,890 shares issued and outstanding, liquidation preference of $72,890	$	79,329	$	80,939

On June 30, 2003, we redeemed the remaining outstanding shares of Series A Convertible Preferred stock and warrants for approximately $24.4 million in cash.

On June 28, 2002, we consummated an agreement with the holders of the Series A Convertible Preferred stock (the "Preferred Stock Recapitalization Agreement") to redeem a portion of the outstanding Series A Convertible Preferred stock and warrants in exchange for cash, shares of common stock, and shares of a newly created and designated preferred stock ("Series B Redeemable Convertible Preferred Stock"). The Preferred Stock Recapitalization Agreement resulted in the redemption of 157,715 shares of Series A Convertible Preferred stock and warrants to purchase 9,841,493 shares of common stock in exchange for the (i) issuance of 72,890 shares of Series B Redeemable Convertible Preferred Stock with a fair value of approximately $80.9 million, (ii) issuance of 11,902,705 shares of common stock with a fair value of approximately $59.5 million, and (iii) a cash payment of approximately $21.3 million. The initial carrying amount of the Series B Redeemable Convertible Preferred Stock of approximately $80.9 million will be decreased ratably over its 5-year term until it equals its liquidation value of approximately $72.9 million with an equal reduction in the amount of preferred stock dividends recorded for financial reporting purposes. The fair value of the consideration paid to the holders of the Series A Convertible Preferred Stock and warrants exceeded their financial statement carrying amount by approximately $1.5 million, which has been treated in a manner similar to preferred stock dividends in the accompanying consolidated financial statements.

At June 30, 2003 and 2002, there are 72,890 shares of Series B Redeemable Convertible Preferred Stock outstanding. The Series B Redeemable Convertible Preferred Stock has a liquidation value of $1,000 per share, bears dividends at the rate of 6% per annum of the liquidation value, and is mandatorily redeemable between June 30, 2007 and December 31, 2007 for shares of common stock and/or cash at our option, subject to limitations on the total number of common shares permitted to be used in the exchange and issued to any shareholder. Dividends are cumulative and payable quarterly. The dividends are payable in cash, unless precluded by contract or the Working Capital Credit Facility, in which case dividends are payable in additional shares of Series B Redeemable Convertible Preferred Stock. The Series B Redeemable Convertible Preferred Stock may be put to us, at the option of the holder, for cash equal to the greater of its liquidation value or conversion value upon the future occurrence of a fundamental change (including those relating to sale of substantially of the assets, delisting of our common stock from a national exchange, change in control, bankruptcy filing, and an event of default that accelerates the repayment of our debt). We may call the outstanding shares of Series B Redeemable Convertible Preferred Stock after June 30, 2005 if certain specified conditions are met. The Series B Redeemable Convertible Preferred Stock is convertible, at the option of the holder, into common stock at $6.60 per share, subject to adjustment upon the occurrence of specified future events. The holders of the Series B Redeemable Convertible Preferred Stock have the right to vote on all matters (except the election of directors) with the holders of the common stock (voting collectively as a single class).

Preferred stock dividends on the Series A Convertible Preferred stock were $1.2 million, $11.4 million, and $9.0 million for the years ended June 30, 2003, 2002 and 2001, respectively. Preferred Stock dividends on the Series B Redeemable Convertible Preferred Stock were $2.8 million for the year ended June 30, 2003. The amount of the Series B Redeemable Convertible Preferred Stock dividend recognized for financial reporting purposes for the year ended June 30, 2003 is composed of the amount of the dividend payable and paid to the holders of the Series B Redeemable Convertible Preferred Stock of $4.4 million offset by the amortization of the premium on the carrying amount of the Series B Redeemable Convertible Preferred Stock of $1.6 million.

(13) COMMON STOCK

At June 30, 2003 and 2002, we were authorized to issue up to 80,000,000 shares of common stock with a par value of $0.01 per share. At June 30, 2003 and 2002, there were 40,685,690 shares and 39,942,658 shares issued and outstanding, respectively. Our Working Capital Credit Facility, Senior Subordinated Notes and the certificate of designation of our Series B Redeemable Convertible Preferred stock contain restrictions on the payment of dividends on our common stock.

We have a restricted stock plan that provides for awards of common stock to certain key employees, subject to forfeiture if employment terminates prior to the vesting dates. At the date of grant, the market value of shares awarded under the plan is recorded in common stockholders' equity as deferred

stock-based compensation. Information about restricted common stock activity for the years ended June 30, 2003, 2002 and 2001 is as follows:

	Total shares	Vested shares	Unvested shares
Outstanding at June 30, 2000	295,500	68,000	227,500
Granted	512,680		512,680
Cancelled	(29,020)		(29,020)
Repurchased	(201)	(201)	
Vested		22,750	(22,750)

	Total shares	Vested shares	Unvested shares
Outstanding at June 30, 2001	778,959	90,549	688,410
Granted	420,500		420,500
Cancelled	(104,170)		(104,170)
Repurchased	(20,573)	(20,573)	
Vested		90,772	(90,772)
Outstanding at June 30, 2002	1,074,716	160,748	913,968
Granted	840,500		840,500
Cancelled	(51,080)		(51,080)
Repurchased	(49,437)	(49,437)	
Vested		187,209	(187,209)
Outstanding at June 30, 2003	1,814,699	298,520	1,516,179

During the years ended June 30, 2003, 2002 and 2001, we recognized deferred-stock based compensation associated with restricted common stock granted to certain key employees of approximately $3.6 million, $2.1 million, and $2.4 million, respectively, which is being amortized to income over their respective four-year vesting period.

During the year ended June 30, 2003, two employees experienced a change in employment status. Following the change in employment status, the former employees began to provide consulting services. Pursuant to the existing terms of our stock option plans, the employees were permitted to retain their original grants of stock options and awards of restricted stock. In accordance with FASB Interpretation No. 44, *Accounting for Certain Transactions involving Stock Compensation*, we recognized deferred-stock based compensation of approximately $0.3 million, which is being amortized to income over their respective vesting periods. The deferred-stock based compensation was calculated using the Black-Scholes model for the unvested portion of the original grants at the date of change in employment status.

During the year ended June 30, 2001, 261,280 shares of restricted common stock were issued to employees in exchange for the cancellation of 1,681,300 stock options with exercise prices ranging from $11.00 to $17.25 per share that had been granted to employees in prior years.

Amortization of deferred compensation of approximately $2.2 million, $1.5 million and $1.3 million is included in selling, general and administrative expense for the years ended June 30, 2003, 2002 and 2001, respectively.

(14) STOCK OPTIONS

We had three stock option plans (the "1991 Plan", the "1995 Plan" and the "1997 Plan") under which stock options had been granted to employees. The 1991 Plan and the 1995 Plan have been terminated as all previously granted stock options have been exercised or cancelled. There were no options granted during the year ended June 30, 2003. Options previously granted under the 1997 Plan expire

no later than ten years from the date of grant. Options granted under the 1997 Plan vest 10% after the end of the first year, 20% after the end of the second year, 30% after the end of the third year, and 40% after the end of the fourth year. Information about stock option activity for the years ended June 30, 2003, 2002 and 2001, is as follows:

	Terminated Plans		1997 Plan	
	Shares	Weighted average exercise price	Shares	Weighted average exercise price
Outstanding at June 30, 2000	719,950	3.96	2,897,240	11.42
Granted			750,000	3.75

	Terminated Plans		1997 Plan	
Cancelled	(49,500)	5.42	(2,478,410)	12.22
Exercised	(372,000)	2.70		
Outstanding at June 30, 2001	298,450	5.28	1,168,830	4.81
Granted			75,000	5.05
Cancelled	(35,000)	5.50	(174,050)	6.68
Exercised	(33,000)	3.50	(7,000)	5.13
Outstanding at June 30, 2002	230,450	5.50	1,062,780	4.52
Granted				
Cancelled	(230,450)	5.50	(55,080)	4.69
Exercised			(3,200)	3.75
Outstanding at June 30, 2003			1,004,500	4.51
Exercisable at June 30, 2003			388,900	4.93

Information about stock options outstanding at June 30, 2003 is as follows:

				Options exercisable		
	Range of exercise prices	Number outstanding	Weighted average remaining life in years	Weighted average exercise prices	Number exercisable	Weighted average exercise prices
1997 Plan	3.75 - 7.25	990,000	7.5	4.40	374,400	4.66
	11.00 - 13.50	13,500	5.6	11.56	13,500	11.56
	17.25	1,000	4.2	17.25	1,000	17.25
		1,004,500			388,900	

(15) EMPLOYEE BENEFIT PLAN

We have established a 401(k) retirement savings plan for all employees. The plan allows participants to contribute a percentage of their compensation ranging from 1% to a maximum of 15%, subject to the maximum salary deferral allowed by the Internal Revenue Service. Employees vest 25% per year in our discretionary contributions, as determined by management based upon our financial performance. Our discretionary contributions for the years ended June 30, 2003, 2002 and 2001, were approximately \$0.6 million, \$0.5 million and \$0.6 million, respectively.

(16) INCOME TAXES

Total income tax expense (benefit) consists of the following (in thousands):

	Years ended June 30,		
	2003	2002	2001
Continuing operations	$ 8,510	$ 5,465	$ 6,666

	Years ended June 30,		
Cumulative effect of a change in accounting principle	(795)		
Total income taxes	$ 7,715	$ 5,465	$ 6,666

Income tax expense (benefit) from continuing operations consists of the following (in thousands):

	Years ended June 30,		
	2003	2002	2001
Current:			
Federal income taxes	$	$ (240)	$ (288)
State income taxes	315	643	735
Current income taxes	315	403	447
Deferred:			
Federal income taxes	7,805	4,483	5,500
State income taxes	390	579	719
Deferred income taxes	8,195	5,062	6,219
Income tax expense	$ 8,510	$ 5,465	$ 6,666

Income tax expense differs from the amount computed by applying the federal corporate income tax rate of 35% to pretax earnings as a result of the following (in thousands):

	Years ended June 30,		
	2003	2002	2001
Computed "expected" tax expense	$ 5,814	$ 4,908	$ 6,458
Increase (reduction) in income taxes resulting from:			
Change in cumulative temporary differences	1,700	(273)	(331)
State income taxes, net of federal income tax benefit	452	387	945
Other, net	544	443	(406)
Income tax expense	$ 8,510	$ 5,465	$ 6,666

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are as follows (in thousands):

	June 30, 2003	June 30, 2002

	June 30, 2003	June 30, 2002
Deferred tax assets:		
Net operating loss and tax credit carry forwards	$ 31,354	$ 32,463
Allowance for doubtful accounts	220	475
Accrual for lease abandonment, corporate relocation and transition plan	1,243	1,953
Other non-deductible accruals	3,881	2,920
Deferred debt issuance costs, principally due to differences in amortization methods		1,327
Intangible assets, principally due to differences in amortization methods and impairment allowances	4,937	5,417
Deferred compensation	1,444	925
Inventories discretionary and minimum volumes, principally due to differences in accounting methods	8,652	6,047
Accrued environmental obligations	2,120	710
Deferred tax assets	53,851	52,237
Deferred tax liabilities:		
Plant and equipment, principally due to differences in depreciation methods and impairment allowances	(51,628)	(43,175)
Deferred revenue supply management services	(737)	(1,180)
Investments in affiliated companies, principally due to undistributed earnings	(1,004)	
Deferred tax liabilities	(53,369)	(44,355)
Net deferred tax assets	$ 482	$ 7,882

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment.

Based upon projections for future taxable income over the periods which the deferred tax assets are deductible, management believes the "more likely than not" criteria has been satisfied as of June 30, 2003 and 2002, and that the benefits of future deductible differences will be realized.

At June 30, 2003, we have net operating loss carry forwards for federal income tax purposes of approximately $82.5 million which are available to offset future federal taxable income, if any, through 2021. The amount and expiration date of the net operating loss carry forwards for federal income tax purposes are as follows: $1.1 million 2018, $27.8 million 2019, $39.5 million 2020, and $14.1 million 2021.

(17) COMMITMENTS AND CONTINGENCIES

Transportation and Deficiency Agreements. In connection with our June 30, 2001 sale of two product distribution facilities in Little Rock, Arkansas, we are potentially liable for payments of up to $725,000 per year for a five-year period through June 30, 2006. The potential liability for each year is based on the actual throughput volumes of the facility for each year as compared to the contractual thresholds of 20,000 and 32,500 barrels per day ("BPD"). If actual volumes exceed 32,500 BPD, we

will not be obligated to pay any of the $725,000 for that given year. If actual volumes are between 20,000 and 32,500 BPD, we will be obligated to pay a prorated portion of the $725,000 for that given year. If actual volumes are less than 20,000 BPD, we are obligated to pay the entire $725,000 for that given year. For the year ended June 30, 2002, our actual volumes were between 20,000 and 32,500 BPD. As a result, we recognized an accrued liability of approximately $1.0 million with an offsetting reduction in net operating margins attributable to our supply, distribution and marketing operations for the shortfall in our current year volumes and our estimated shortfall in volumes for the remainder of the term of the agreement. For the year ended June 30, 2003, our actual volumes were less than our contractual volumes but approximated our volumes we estimated in the prior year. As a result we paid approximately $0.2 million pursuant to the deficiency agreement with an offsetting reduction in the accrued liability. The accrued liability balance of approximately $0.8 million at June 30, 2003 represents our estimate of the future payments we expect to pay for our anticipated shortfall in volumes for the remainder of the term of the agreement (see Note 9 of Notes to consolidated financial statements).

We also are subject to three transportation and deficiency agreements ("T&D's") with three separate interstate pipeline companies. Each agreement calls for guaranteed minimum shipping volumes over the term of the agreements. If actual volumes shipped are less than the guaranteed minimum volumes, we must make payment to the interstate pipeline company for any shortfall at the contracted pipeline tariff. Such payments are accounted for as prepaid transportation, since we have a contractual timeframe, after the end of the term of the T&D, to apply the amounts to charges for using the interstate pipeline in the future. We monitor the actual volumes shipped against our obligations to determine if the T&D payments made will ultimately be recovered. In order to do this, we have to estimate our future shipping volumes.

During the years ended June 30, 2003, 2002 and 2001, we made payments of approximately $0.6 million, $0.4 million and $3.2 million, respectively, pursuant to the T&D agreements because our actual volumes shipped during those years were less than the guaranteed minimum volumes for those years. During the year ended June 30, 2001, we also recognized an accrued liability of approximately $1.6 million representing our estimate of the future payments we expect to pay for the estimated shortfall in volumes for the remainder of the terms of the T&D agreements. During the years ended June 30, 2003 and 2002, we recognized an additional (reduction in) accrued liability of approximately ($0.4) million and $0.2 million, respectively, representing a change in our estimate of the future payments we expect to pay for the estimated shortfall in volumes for the remainder of the terms of the T&D agreements. For the years ended June 30, 2003, 2002 and 2001, we increased (reduced) net operating margins attributable to our supply, distribution and marketing operations by approximately $0.4 million, $(0.6) million and $(2.2) million, respectively. At June 30, 2003 and 2002, we included approximately $3.0 million and $2.6 million, respectively, of prepaid transportation in other assets (see Note 8 of Notes to consolidated financial statements).

(in thousands)	**June 30, 2002**	**Payments during the period**	**Change in estimate during the period**	**June 30, 2003**
Other assets prepaid transportation	$ 2,644	$ 377	$	$ 3,021
Accrued liability T&D obligations	$ (2,839)	$ 419	$ 407	$ (2,013)

Operating Leases. On April 19, 2002, we executed a 10-year non-cancelable operating lease for new office space to accommodate our corporate headquarters. The lease commenced on October 1, 2002 and July 1, 2003 with respect to approximately one-half of the total leased square footage,

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respectively. We also lease office space in Atlanta, Georgia, pipeline and terminal capacity, and property and equipment under non-cancelable operating leases that expire through June 2010. At June 30, 2003, future minimum lease payments under these non-cancelable operating leases are as follows (in thousands):

Years ending June 30:	**Office space**	**Terminal and pipeline capacity**	**Property and equipment**
2004	$ 1,251	$ 2,837	$ 248
2005	1,558	2,318	157
2006	1,574	601	120
2007	1,541	162	58
2008	1,507		
Thereafter	5,574		
	$ 13,005	$ 5,918	$ 583

Rental expense under operating leases was $4.1 million, $3.6 million, and $3.9 million for the years ended June 30, 2003, 2002 and 2001, respectively.

(18) LITIGATION

We have been named as a defendant in various lawsuits and we are a party to various other legal proceedings, in the ordinary course of business, some of which are covered in whole or in part by insurance. We believe that the outcome of such lawsuits and other proceedings will not individually or in the aggregate have a material adverse effect on our consolidated financial condition, results of operations or cash flows. For the years ended June 30, 2003, 2002 and 2001, we incurred outside third-party legal and settlement expenses of approximately $1.6 million, $0.7 million and $0.7 million, respectively, that are included in selling, general and administrative expenses in the accompanying consolidated statement of operations.

(19) EARNINGS PER SHARE

The following tables reconcile the computation of basic EPS and diluted EPS (in thousands, except per share amounts).

	Years ended June 30,		
	2003	2002	2001
Net earnings	$ 6,803	$ 8,558	$ 11,338
Preferred stock dividends, net	(3,984)	(11,351)	(8,963)
Net earnings (loss) attributable to common stockholders for basic and diluted EPS	$ 2,819	$ (2,793)	$ 2,375
Basic weighted average shares	39,116	31,267	30,879
Effect of dilutive securities:			
Restricted common stock subject to continuing vesting requirements	22		
Stock options	125		100
Stock purchase warrants			24
Diluted weighted average shares	39,263	31,267	31,003
Earnings (loss) per share:			
Basic	$ 0.07	$ (0.09)	$ 0.08
Diluted	$ 0.07	$ (0.09)	$ 0.08

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We exclude potentially dilutive securities from our computation of diluted earnings per share when their effect would be anti-dilutive. The following securities were excluded from the earnings per share computation, as their inclusion would have been anti-dilutive:

	June 30, 2003	June 30, 2002	June 30, 2001
Restricted common stock subject to continuing vesting requirements	693,179	913,968	688,410
Common stock issuable upon exercise of stock options	397,500	1,293,230	688,280
Common stock issuable upon exercise of stock purchase warrants		900,045	6,804,940
Common stock issuable upon conversion of:			
Series A Convertible Preferred Stock		1,628,083	11,655,000
Series B Redeemable Convertible Preferred Stock	11,043,939	11,043,939	
	12,134,618	15,779,265	19,836,630

	June 30, 2003	June 30, 2002	June 30, 2001

For the year ended June 30, 2003, certain shares of restricted common stock subject to continuing vesting requirements were excluded from the computation of earnings per share because the associated unamortized deferred compensation exceeded the average quoted market price of our common stock during the period, stock options were excluded because their exercise prices exceeded the average quoted market price of our common stock during the period, and the Series B Redeemable Convertible Preferred stock was excluded because its dividend yield exceeded the equivalent earnings per share under the if-converted method. For the year ended June 30, 2003, the excluded stock options had a weighted average exercise price of $5.68 per share and, the Series B Redeemable Convertible Preferred Stock had a conversion price of $6.60.

(20) DISCLOSURES ABOUT FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of financial instruments at June 30, 2003 and 2002.

Cash and Cash Equivalents, Trade Receivables and Trade Accounts Payable. The carrying amount approximates fair value because of the short-term maturity of these instruments.

Debt. The carrying values of the commodity margin loan and bank credit facility approximate fair value since they bear interest at current market interest rates. The fair value of the Senior Subordinated Notes was approximately $210 million based on quoted market prices.

(21) BUSINESS SEGMENTS

We provide integrated terminal, transportation, storage, supply, distribution and marketing services to refiners, wholesalers, distributors, marketers, and industrial and commercial end-users of refined petroleum products. We conduct business in the following business segments:

> *Supply, distribution and marketing* consists of services for the supply and distribution of refined petroleum products through rack sales, bulk sales and contract sales in the physical and derivative markets, with retail, wholesale, industrial and commercial customers using our truck terminal rack locations and marine refueling equipment, and providing related value-added fuel procurement and supply management services.

> *Terminals, pipelines, and tugs and barges* consists of an extensive terminal and pipeline infrastructure that handles refined petroleum products with transportation connections via pipelines, barges, vessels, rail cars and trucks to our facilities or to third-party facilities with an emphasis on

transportation connections primarily through the Colonial, Plantation, TEPPCO, Explorer and Williams pipeline systems.

Our chief operating decision maker is our chief executive officer ("CEO"). Our CEO reviews the financial performance of our business segments using a financial performance measure that is referred to by us as "adjusted net operating margins" for purposes of making operating decisions and assessing financial performance. Accordingly, we present "adjusted net operating margins" for each of our two business segments: (i) terminals, pipelines, and tugs and barges and (ii) supply, distribution and marketing.

For the terminals, pipelines, and tugs and barges segment, "adjusted net operating margins" is composed of revenues less direct operating costs and expenses. There are no differences between "adjusted net operating margins" for our terminals, pipelines, and tugs and barges segment and the net operating margins reported for that segment in our accompanying historical financial statements.

For our supply, distribution and marketing segment, "adjusted net operating margins" is composed of revenues less cost of product sold and other direct costs and expenses. For purposes of computing our "adjusted net operating margins" for the supply, distribution and marketing segment, cost of product sold is reflected at fair value, which matches the treatment of our derivative and risk management contracts. Additionally, for purposes of computing our "adjusted net operating margins," our discretionary inventories base operating inventory volumes are maintained at original cost. The differences between "adjusted net operating margins" for the supply, distribution and marketing segment and the net operating margins reported for that segment in our accompanying historical financial statements are presented as "Inventory Adjustments" in the accompanying "Reconciliation to Earnings Before Income Taxes."

The financial performance of our business segments is as follows (in thousands):

	Year ended June 30, 2003	Year ended June 30, 2002
Terminals, pipelines, and tugs and barges:		
Historical facilities	$ 42,384	$ 35,718
Coastal facilities	5,408	
Adjusted net operating margins	47,792	35,718
Supply, distribution and marketing:		
Light oil margins	37,137	54,803
Heavy oil margins	6,299	
Supply management services margins	13,017	13,888
Trading margins, net	(1,139)	56
Adjusted net operating margins	55,314	68,747
Total adjusted net operating margins	$ 103,106	$ 104,465
Reconciliation to Earnings Before Income Taxes:		
Adjusted net operating margins	$ 103,106	$ 104,465
Inventory Adjustments:		
Gains recognized on beginning inventories discretionary volumes	12,644	
Gains deferred on ending inventories discretionary volumes held for immediate sale or exchange	(5,855)	
Increase in FIFO cost basis of base operating inventory volumes	415	
Lower of cost or market write-downs on base operating inventory volumes	(12,435)	
Net operating margins	97,875	104,465
Other Items:		
Selling, general and administrative expenses	(41,940)	(41,527)
Depreciation and amortization	(19,371)	(16,556)
Lower of cost or market write-downs on product linefill and tank bottom volumes	(633)	(12,963)
Operating income	35,931	33,419
Other income (expense), net	(19,321)	(19,396)
Earnings before income taxes	$ 16,610	$ 14,023

Supplemental information about our business segments is summarized below (in thousands):

	Year ended June 30, 2003
	Corporate

	Year ended June 30, 2003			
	Supply, distribution and marketing	Terminals, pipelines, tugs and barges		Total consolidated
Revenues from external customers	$ 8,241,001	$ 35,336	$	$ 8,276,337
Inter-segment revenues		47,652		47,652
Revenues	$ 8,241,001	$ 82,988	$	$ 8,323,989
Identifiable assets	$ 530,423	$ 390,349	$ 65,297	$ 986,069
Capital expenditures	$ 649	$ 137,998	$ 862	$ 139,509

	Year ended June 30, 2002			
	Supply, distribution and marketing	Terminals, pipelines, tugs and barges	Corporate	Total consolidated
Revenues from external customers	$ 6,001,170	$ 27,390	$	$ 6,028,560
Inter-segment revenues		35,996		35,996
Revenues	$ 6,001,170	$ 63,386	$	$ 6,064,556
Identifiable assets	$ 441,474	$ 253,417	$ 40,437	$ 735,328
Capital expenditures	$ 62	$ 13,592	$ 2,155	$ 15,809

	Year ended June 30, 2001			
	Supply, distribution and marketing	Terminals, pipelines, tugs and barges	Corporate	Total consolidated
Revenues from external customers	$ 5,182,492	$ 36,423	$	$ 5,218,915
Inter-segment revenues		43,284		43,284
Revenues	$ 5,182,492	$ 79,707	$	$ 5,262,199
Identifiable assets	$ 298,572	$ 332,717	$ 81,076	$ 712,365
Capital expenditures	$ 1,222	$ 8,585	$ 1,735	$ 11,542

(22) FINANCIAL RESULTS BY QUARTER (UNAUDITED)

(in thousands, except per share amounts)

	Three months ended September 30, 2002	Three months ended December 31, 2002 (as restated)	Three months ended March 31, 2003 (as restated)	Three months ended June 30, 2003	Year ended June 30, 2003
Revenues	$ 1,744,736	$ 2,023,857	$ 2,342,829	$ 2,212,567	$ 8,323,989
Net operating margins	$ 18,540	$ 1,821	$ 57,509	$ 20,005	$ 97,875
Net earnings (loss) attributable to common stockholders	$ (459)	$ (10,732)	$ 21,384	$ (7,374)	$ 2,819
Earnings (loss) per common share					
Basic	$ (0.01)	$ (0.27)	$ 0.54	$ (0.19)	$ 0.07
Diluted	$ (0.01)	$ (0.27)	$ 0.54	$ (0.19)	$ 0.07

	Three months ended September 30, 2001	Three months ended December 31, 2001	Three months ended March 31, 2002	Three months ended June 30, 2002	Year ended June 30, 2002
Revenues	$ 1,549,758	$ 1,172,856	$ 1,325,699	$ 2,016,243	$ 6,064,556
Net operating margins	$ 35,940	$ 22,242	$ 29,702	$ 16,581	$ 104,465
Net earnings (loss) attributable to common stockholders	$ 7,227	$ (5,377)	$ 6,265	$ (10,908)	$ (2,793)
Earnings (loss) per common share					
Basic	$ 0.23	$ (0.17)	$ 0.19	$ (0.35)	$ (0.09)
Diluted	$ 0.22	$ (0.17)	$ 0.19	$ (0.35)	$ (0.09)

For the year ended June 30, 2002 and all prior periods, we originally presented revenues from our supply, distribution and marketing operation on a net basis in accordance with EITF 98-10. The final consensus on EITF 02-03 concluded that all gains and losses (realized and unrealized) on derivative contracts held for trading purposes are to be presented on a net basis in the consolidated statement of operations whether or not the contracts are settled physically. Gains and losses on all other energy-related contracts that are settled physically are to be presented on a gross basis in the consolidated statements of operations. Accordingly, certain of our revenues have been recast to be presented on a gross basis for all periods presented.

On February 28, 2003, we acquired all of the outstanding shares of capital stock of Coastal Fuels Marketing, Inc. and its subsidiary, Coastal Tug and Barge, Inc., from El Paso CGP Company ("CGP") along with the rights to and operations of the southeast marketing division of El Paso Merchant Energy Petroleum Company ("EPME-PC"). The consolidated financial statements include the results of operations of the Coastal Fuels assets from the closing date of the transaction (February 28, 2003).

We have restated our results of operations for the three months ended December 31, 2001 and March 31, 2002. We previously reported that we included in net operating margins attributable to our supply, distribution and marketing activities approximately $18.9 million of margins from the transfer of minimum inventory volumes to discretionary inventory volumes and their subsequent sale to customers during the three months ended March 31, 2003. Of the approximately $18.9 million of margins reported for the three months ended March 31, 2003, approximately $10.6 million of the increase in the value of the inventories base operating inventory volumes was attributable to periods on or before October 1, 2002 and, therefore, that amount, net of related income taxes of approximately $4.0 million, now has been changed to be reported as a component of the cumulative effect of the change in accounting principle upon adoption of EITF 02-03 in the three months ended December 31, 2002 (See Note 1(c) of Notes to consolidated financial statements).

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

There were no changes in and disagreements with accountants on accounting and financial disclosures during the year ended June 30, 2003.

ITEM 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to ensure that information required to be discl