SECURITIES AND EXCHANGE COMMISSION

FORM 10-K

Annual report pursuant to section 13 and 15(d)

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COASTAL CORP

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

For the fiscal year ended December 31, 1998 or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

For the transition period from ____________ to ____________

Commission file number 1-7176

THE COASTAL CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	74-1734212
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Coastal Tower Nine Greenway Plaza Houston, Texas	77046-0995
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (713) 877-1400

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

Title of each class		Name of each exchange on which registered
Common Stock ($.33 1/3 par value)		
$1.19 Cumulative Convertible Preferred Stock, Series A ($.33 1/3 par value)		
$1.83 Cumulative Convertible Preferred Stock, Series B ($.33 1/3 par value)		
8.375% Coastal Trust Preferred Securities issued by Coastal Finance I		
10-1/4% Senior Debentures	8-1/8% Senior Notes	} New York Stock Exchange
10-3/8% Senior Notes	7-3/4% Senior Debentures	
10-3/4% Senior Debentures	7.42% Senior Debentures	
10% Senior Notes	6.70% Senior Debentures	
9-3/4% Senior Debentures	6.50% Senior Debentures	
8-3/4% Senior Notes	6.95% Senior Debentures	
9-5/8% Senior Debentures	6.375% Senior Debentures	

Securities registered pursuant to Section 12(g) of the Act:
Class A Common Stock ($.33-1/3 par value)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, 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. [ ]

As of March 10, 1999, there were outstanding 212,486,660 shares of common stock, 351,624 shares of Class A common stock, 55,809 shares of $1.19 Cumulative Convertible Preferred Stock, Series A, 60,696 shares of $1.83 Cumulative

Convertible Preferred Stock, Series B and 27,714 shares of $5.00 Cumulative Convertible Preferred Stock, Series C, of the Registrant. The aggregate market value on such date of the voting stock of the Registrant held by non-affiliates was an estimated $6.81 billion, based on the closing prices in the daily composite list for transactions on the New York Stock Exchange and other markets.

Documents incorporated by reference:

Portions of the Registrant's Proxy Statement for the 1999 Annual Meeting of Stockholders, filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, referred to in Part III hereof.

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GLOSSARY

"AICPA" means American Institute of Certified Public Accountants

"ANR Pipeline" means ANR Pipeline Company and its subsidiaries

"ANR Storage" means ANR Storage Company and its subsidiaries

"Bcf" means billion cubic feet

"BTU" means British thermal unit

"CIG" or "Colorado" means Colorado Interstate Gas Company and its subsidiaries

"Coastal" or "Company" means The Coastal Corporation and its subsidiaries

"EPA" means Environmental Protection Agency

"FAS" means Statement of Financial Accounting Standards

"FASB" means Financial Accounting Standards Board

"FERC" means Federal Energy Regulatory Commission

"Great Lakes" means Great Lakes Gas Transmission Limited Partnership

"Huddleston" means Huddleston & Co., Inc., Houston, Texas - (Volumes in the Huddleston Report are at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit)

"Long tons" means weight measurement of 2,240 pounds

"Mcf" means thousand cubic feet

"MMcf" means million cubic feet

"NGA" means Natural Gas Act of 1938, as amended

"Order 636" means FERC Order No. 636 which required significant changes in services provided by interstate natural gas pipelines, including the unbundling of services

"TransCanada" means TransCanada PipeLines Limited

"WIC" means Wyoming Interstate Company, Ltd.

"working gas" means that volume of gas available for withdrawal from natural gas storage fields and use by the Company's customers

NOTES:

The terms "Coastal" and "Company" are used in this Annual Report for purposes of convenience and are intended to refer to The Coastal Corporation and/or its subsidiaries either individually or collectively, as the context may require. These references are not intended to suggest that the various Coastal companies referred to are not independent corporate entities having their separate corporate identities and managements.

This Annual Report includes certain forward-looking statements. The forward-looking statements reflect the Company's expectations, objectives and goals with respect to future events and financial performance and are based on assumptions and estimates which the Company believes are reasonable. However, actual results could differ materially from anticipated results. Important factors which may affect the actual results include, but are not limited to, commodity prices, political developments, market and economic conditions, industry competition, the weather, changes in financial markets, changing legislation and regulations, and the impact of the Year 2000 issue. The forward-looking statements contained in this Report are intended to qualify for the safe harbor provisions of Section 21E of the Securities Exchange Act of

1934, as amended.

Unless otherwise noted, all natural gas volumes presented in this Annual Report are stated at a pressure base of 14.73 pounds per square inch absolute and 60 degrees Fahrenheit.

PART I

Item 1. Business.

INTRODUCTION

Coastal, acting through its subsidiaries, is a diversified energy holding company with subsidiary operations in natural gas gathering, marketing, processing, storage and transmission; petroleum refining, marketing and distribution and chemicals; gas and oil exploration and production; coal mining; and power. The Company was incorporated under the laws of Delaware in 1972 to become the successor parent, through a corporate restructuring, of a corporate enterprise founded in 1955. The Company employed approximately 13,300 persons as of December 31, 1998.

Annual Reports on Form 10-K for the year ended December 31, 1998 are also filed by Coastal's subsidiaries, ANR Pipeline and Colorado. Such reports contain additional details concerning the reporting organizations.

Selected financial information of the Company by industry segment for the years ended December 31, 1998, 1997 and 1996, is set forth in Note 9 of the Notes to Consolidated Financial Statements included herein. Information concerning inventories is set forth in Note 2 of the Notes to Consolidated Financial Statements included herein.

NATURAL GAS SYSTEMS

OPERATIONS

General

Natural gas operations involve the production, purchase, gathering, processing, transportation, balancing, storage, marketing and sale of natural gas to and for utilities, industrial customers, marketers, producers, distributors, other pipeline companies and end users.

ANR Pipeline is involved in the transportation, storage, gathering and balancing of natural gas. ANR Pipeline provides these services for various customers through its facilities located in Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Nebraska, Ohio, Oklahoma, Tennessee, Texas, Wisconsin and offshore in federal waters. ANR Pipeline operates two offshore gas pipeline systems in the Gulf of Mexico which are owned by High Island Offshore System, a limited liability company, and U-T Offshore System, a general partnership, both of which are composed of ANR Pipeline subsidiaries and subsidiaries of other companies. ANR Pipeline operates wholly owned and partially owned storage fields of ANR Storage in Michigan. ANR Pipeline also operates Empire State Pipeline, an intrastate pipeline extending from Niagara Falls to Syracuse, New York, in which an affiliate of ANR Pipeline has a 50% interest.

ANR Pipeline's two interconnected, large-diameter multiple pipeline systems transport gas to the Midwest and the Northeast from (a) the Hugoton Field and other fields in the Anadarko Basin in Texas and Oklahoma, (b) the Louisiana onshore and the Louisiana and Texas offshore areas and (c) gas originating in other basins received through interconnections located throughout its system.

ANR Pipeline's principal pipeline facilities at December 31, 1998 consisted of 10,600 miles of pipeline and 74 compressor stations with 1,022,031 installed horsepower. At December 31, 1998, the design peak day delivery capacity of the transmission system, considering supply sources, storage, markets and transportation for others, was approximately 5.9 Bcf per day.

Colorado is involved in the production, purchase, gathering, processing, transportation, storage and sale of natural gas. Colorado's gas transmission system extends from gas production areas in the Texas Panhandle, western Oklahoma and western Kansas, northwesterly through eastern Colorado to the Denver area, and from production areas in Montana, Wyoming and Utah, southeasterly to the Denver area. Colorado's gas gathering and processing facilities are located

throughout the production areas adjacent to its transmission system. Most of Colorado's gathering facilities connect directly to its transmission system, but some gathering systems are connected to other pipelines. Colorado owns four underground gas storage fields - three located in Colorado and one in Kansas.

Colorado's principal transmission and storage pipeline facilities, including certain facilities in the Panhandle Field of Texas ("Panhandle Field"), at December 31, 1998 consisted of 4,351 miles of pipeline and 58 compressor stations with approximately 296,300 installed horsepower. At December 31, 1998, the design peak day gas delivery capacity of the transmission system was approximately 2.2 Bcf per day. The underground gas storage facilities have a working capacity of approximately 29 Bcf and a peak day delivery capacity of approximately 775 MMcf.

Colorado's gathering facilities, excluding certain FERC regulated facilities in the Panhandle Field, consist of 2,372 miles of gathering lines and approximately 50,700 horsepower of compression. Colorado owned and operated five gas processing plants in 1998. These plants, with a total operating capacity of approximately 512 MMcf daily, recover mainly propane, butanes, natural gasoline, sulfur and other by-products, which are sold to refineries, chemical plants and other customers.

Competition

Natural gas competes with other forms of energy available to customers, primarily on the basis of price paid by end users. These competitive forms of energy include electricity, coal, propane and fuel oils. Changes in the availability or price of natural gas or other forms of energy, as well as changes in business conditions, conservation, legislation or governmental regulations, capability to convert to alternate fuels, changes in rate structure, taxes and other factors may affect the demand for natural gas in the areas served by ANR Pipeline and Colorado.

In recent years, the FERC has issued orders which have resulted in more competition within the natural gas industry. This competition has intensified, resulting in more rate competition among pipelines in order to increase and maintain market share and maximize capacity utilization. ANR Pipeline's and Colorado's transportation and storage services are influenced by their respective customers' access to alternative service providers and the price of such services. The FERC's orders have also resulted in competition between ANR Pipeline and Colorado and their respective customers by allowing the customers to resell their unused capacity.

ANR Pipeline competes in its historical market areas of Wisconsin and Michigan with other interstate and intrastate pipeline companies and local distribution companies in the transportation and storage of natural gas. ANR Pipeline also faces competition in the Northeast markets from other interstate pipelines in serving both electric generation and local distribution companies. Increasingly, ANR Pipeline also competes with independent producers and other companies seeking to construct interstate transmission facilities and with a number of marketing companies which aggregate capacity released by firm shippers for the purpose of managing gas requirements for end users. Additionally, Colorado competes with interstate and intrastate pipeline companies in the sale, transportation and storage of natural gas and with independent producers, brokers, marketers, and other pipelines in the gathering, processing and sale of gas within its service area.

ANR PIPELINE

Transportation Services

ANR Pipeline offers an array of transportation, storage and balancing service options under Order 636. Additional information concerning Order 636, including transportation and storage, is set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations" included herein.

ANR Pipeline transports gas to markets on its system and also transports gas to other markets off its system under transportation agreements with other companies, including distributors, intrastate and interstate pipelines, producers, brokers, marketers and end users. Transportation service revenues amounted to $481 million for 1998 compared to $497 million for 1997 and $510 million for 1996. During 1998, approximately 23% of ANR Pipeline's transportation service revenues were from its three largest customers: Wisconsin Gas Company, Wisconsin Electric Power Company Inc. and

Michigan Consolidated Gas Company. Wisconsin Gas Company serves the Milwaukee metropolitan area and numerous other communities in Wisconsin. Wisconsin Electric Power Company Inc. serves the cities of Racine, Kenosha, Appleton and their surrounding areas in Wisconsin. Michigan Consolidated Gas Company serves the city of Detroit and certain surrounding areas, the cities of Grand Rapids and Muskegon, the communities of Ann Arbor and Ypsilanti and numerous other communities in Michigan. In 1998, ANR Pipeline provided approximately 67% and 30% of the total gas requirements of Wisconsin and Michigan, respectively.

ANR Pipeline's system deliveries for the years 1998, 1997 and 1996 were as follows:

Year	Total System Deliveries (Bcf)	Daily Average System Deliveries (MMcf)
1998	1,354	3,710
1997	1,424	3,901
1996	1,517	4,145

Gas Storage

ANR Pipeline has approximately 202 Bcf of underground working gas storage capacity, with a maximum day delivery capacity of 3 Bcf as late as the end of February. Working gas storage capacity operated by ANR Pipeline of 126.3 Bcf is available from five owned and five leased underground storage facilities in Michigan. In addition, ANR Pipeline has the contracted rights for 75.4 Bcf of working gas storage capacity of which 45.4 Bcf is provided by Blue Lake Gas Storage Company and 30 Bcf is provided by ANR Storage. Gas storage revenues amounted to $139 million for 1998 as compared to $146 million for 1997 and $131 million for 1996.

COLORADO

Gas Sales, Storage and Transportation

Colorado's gas sales consist primarily of Company-owned production. Additionally, Colorado engages in "open access" storage and transportation of gas owned by third parties.

Pursuant to an operating agreement with an affiliate, Colorado operates the Young Gas Storage Field located in northeastern Colorado. The field has a working gas storage capacity of 5.3 Bcf, with a peak day delivery capacity of approximately 200 MMcf per day. Such capacity is fully subscribed under 30-year contracts.

Colorado's deliveries for the years 1998, 1997 and 1996 were as follows:

Year	Total System Deliveries (Bcf)	Daily Average System Deliveries (MMcf)
1998	480	1,315
1997	486	1,333
1996	475	1,298

Gas Gathering and Processing

Colorado provides gathering and processing services on an "unbundled" or stand-alone basis. Colorado's processing terms are not regulated by the FERC, but Colorado is required to provide "open access" to its regulated processing facilities. The gathering that Colorado provides in the Panhandle Field continues to be regulated by the FERC, and Colorado is limited to charging rates between minimum and maximum levels approved by the FERC. The gathering (and processing) that Colorado's subsidiary, CIG Field Services Company, provides is not regulated by the FERC.

The gas processing plants recovered approximately 46 million gallons of liquid hydrocarbons in 1998 compared to 55 million gallons in 1997, and 66 million gallons in 1996, as well as 300 long tons of sulfur in 1998, compared to 500 long tons in 1997 and 3,100 long tons in 1996. Additionally, Colorado processed approximately 25 million gallons of liquid hydrocarbons owned by others in 1997 compared to 24 million gallons in 1997 and 6 million gallons in 1996.

Colorado operates two helium processing facilities, one located in eastern Colorado and the other in the western Oklahoma panhandle area. These helium facilities are partially owned by affiliates of Colorado.

ANR STORAGE COMPANY

ANR Storage develops and operates natural gas storage reservoirs to store gas for customers. ANR Storage owns four underground storage fields and related facilities in northern Michigan, the working storage capacity of which is approximately 56 Bcf, including 30 Bcf which is contracted to ANR Pipeline. ANR Storage also owns indirectly a 50% equity interest in two, and a 75% equity interest in one, joint venture owned and operated storage facilities located in Michigan and New York with a total working storage capacity of approximately 65 Bcf. All of the jointly owned capacity is committed under long-term contracts, including 45.4 Bcf which is contracted to ANR Pipeline by Blue Lake Gas Storage Company.

GAS SYSTEM RESERVES

ANR Pipeline

Access to Gas Supply

Shippers on ANR Pipeline have direct access to the two most prolific gas producing areas in the United States, the Gulf Coast and Mid-Continent. Statistics published by the Energy Information Agency, Office of Oil and Gas, U. S. Department of Energy, indicate that approximately 79% of all natural gas in the lower 48 states is produced from these two areas.

In addition, interconnecting pipelines provide shippers, in general, with access to all other major gas producing areas in the United States and Canada. An interconnection with Colorado, an affiliate of ANR Pipeline, provides ANR Pipeline shippers with access to the Rocky Mountain producing area. Rocky Mountain production contributes approximately 15% of total gas production in the lower 48 states. Gas produced in Western Canada, nearly 100% of all Canadian gas production, is accessible to ANR Pipeline shippers through existing interconnections with Great Lakes and Viking Gas Transmission Company ("Viking") and a new interconnection with Northern Border Pipeline Company ("Northern Border").

Gas deliverability available to shippers on ANR Pipeline's system from the Mid-Continent, Rocky Mountain and Gulf Coast producing areas through direct connections and interconnecting pipelines and gatherers is approximately 4,000 MMcf per day. Deliverability of 1,100 MMcf per day from Western Canada is accessible to ANR Pipeline shippers through the Great Lakes and Viking interconnections. The interconnection with Northern Border has the capacity to provide shippers access to an additional 500 MMcf per day of Western Canadian gas.

ANR Pipeline remains active in locating and connecting new sources of natural gas to facilitate transportation arrangements made by third-party shippers. During 1998, field development, newly connected gas wells, gas production facilities and pipeline interconnections contributed over 1,600 MMcf per day to total deliverability accessible to shippers on ANR Pipeline's system.

Colorado

Colorado has reported in its Form 10-K for the year ended December 31, 1998, its Natural Gas System reserves based on information prepared by Huddleston, the Company's independent engineers, while its Exploration and

Production segment reserves are as prepared by the Company and reviewed by Huddleston. Additional information is set forth in "Reserves Dedicated to a Particular Customer," presented below.

Reserves Dedicated to a Particular Customer

Colorado is committed to sell gas to Pioneer Natural Resources, USA, Inc., ("Pioneer"), a customer, under a 1928 agreement, as amended, from specific owned gas reserves in the West Panhandle Field of Texas. Under an amendment which became effective January 1, 1991, a cumulative 23% of the total net production may be taken for customers other than Pioneer.

ALLIANCE PIPELINE PROJECT

Coastal, through subsidiaries, has a 14.4% equity interest in the corporations and partnerships comprising the Alliance Pipeline Project ("Alliance"). Alliance, when completed, will be a 1,900-mile pipeline initially designed to carry 1.325 Bcf of natural gas per day and associated liquids from western Canada to the Chicago-area market center. Alliance will interconnect with, among other pipelines, ANR Pipeline's proposed SupplyLink project and through SupplyLink to the proposed Independence Pipeline, in which an ANR subsidiary owns a one-third general partnership interest. The Independence Pipeline will interconnect with the SupplyLink pipeline at Defiance, Ohio and will extend 400 miles to Leidy, Pennsylvania. In 1998, both the FERC and the Canadian National Energy Board granted approval to proceed with the construction and operation of Alliance. The project is scheduled to be in service by the end of 2000.

WYOMING INTERSTATE COMPANY, LTD.

WIC, a limited partnership owned by two wholly owned Coastal subsidiaries, owns a 269-mile, 36-inch diameter pipeline across southern Wyoming. The WIC pipeline connects with an 88-mile western segment in which a Coastal subsidiary has a 10% interest and is the center section of the 800-mile Trailblazer pipeline system built by a group of companies to move gas from the Overthrust Belt and other Rocky Mountain areas to supply midwestern and eastern markets. WIC is also connected to Colorado's pipeline facilities and Colorado has received FERC approval to continue to hold its capacity on WIC for Colorado's operational needs as well as for certain third parties. Colorado and other companies for which the WIC line transports gas have entered into long-term contracts having forward-haul reservation volumes totaling 756 MMcf daily. In 1998, the WIC line transported an average of 622 MMcf daily, compared to 546 MMcf daily and 486 MMcf daily in 1997 and 1996, respectively. In November 1998, WIC placed in service a further expansion of facilities involving the addition of 7,380 horsepower of compression at WIC's Laramie and Cheyenne compressor stations, which in turn created additional capacity of 52 MMcf per day on the Powder River Lateral. In December, WIC filed with the FERC for approval to construct the Medicine Bow Lateral, a 151-mile pipeline for transporting coal-bed methane gas from the Powder River Basin to WIC's main line west of Cheyenne, Wyoming. WIC has obtained long-term transportation commitments for the Medicine Bow Lateral beginning at 184 MMcf per day and increasing to 454 MMcf per day over a four-year period. The initial phase of this $80.5 million project will provide approximately 269 MMcf per day of capacity, and subject to timely receipt of regulatory approvals, is expected to be in-service by January 1, 2000. WIC intends to file with the FERC in the future for approval to construct additional facilities on the Medicine Bow Lateral to increase capacity to meet the additional contractual commitments.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

Coastal and TransCanada, a non-affiliated company, each own 50% of Great Lakes, which in turn owns a 2,101-mile, 36-inch diameter gas pipeline system from the Manitoba-Minnesota border to an interconnection on the Michigan-Ontario border at St. Clair, Michigan. Great Lakes transported 907 Bcf in 1998 as compared to 910 Bcf in 1997 and 933 Bcf in 1996. Great Lakes has long-term contract commitments to transport a total of 1.68 Bcf per day for TransCanada and affiliates. It also transports up to 1.1 Bcf per day primarily for United States markets, including 224 MMcf per day to Coastal affiliates. Great Lakes exchanges gas with ANR Pipeline by delivering gas in the upper peninsula of Michigan and receiving an equal amount of gas in the lower peninsula of Michigan.

UNREGULATED GAS OPERATIONS

Coastal's unregulated natural gas business, including certain of Coastal's natural gas gathering and processing, gas supply and marketing activities, is operated primarily through two subsidiaries, Coastal Field Services Company ("CFSC") and Coastal Gas International Company ("CGI").

CFSC owns or operates for various affiliates domestic gathering and processing assets in Alabama, Colorado, Kansas, Louisiana, Oklahoma, Texas, Utah, Wyoming, and offshore in the Gulf of Mexico. These assets include interests in more than 3,800 miles of gathering pipelines, which collect gas from almost 3,800 wells. CFSC gathered approximately 1 Bcf per day of gas in 1998, 1997 and 1996. CFSC and its affiliates also have an ownership interest in ten gas processing plants, six of which are operated by CFSC. Natural gas liquids produced at CFSC operated plants and from gas processed by others for CFSC averaged more than 23,000 barrels per day in 1998, as compared to more than 25,000 barrels per day in 1997 and almost 23,000 barrels per day in 1996.

CFSC holds a 13.6% interest in the 250-mile Dauphin Island Gathering Partners ("DIGP") pipeline system which gathers and transports natural gas from major producing areas offshore in the eastern Gulf of Mexico. DIGP transports gas onshore to Louisiana and Alabama, where CFSC holds an interest in a 600 MMcf per day gas processing plant and a 40 MW cogeneration plant. The cogeneration plant will provide power and process heat for the gas plant. The gas plant and associated cogeneration plant are expected to be operational in 1999.

In November 1998, CFSC acquired a 60 MMcf per day gas processing plant and 480 miles of gas gathering systems in Colorado and Utah. During 1998, CFSC also completed the sale of certain Mid-Continent gathering and processing assets.

CGI conducts the international natural gas operations of the Company. In 1998, Coastal Gas Pipelines Victoria Pty Ltd, an affiliate of CGI, completed construction and placed into operation a 113-mile natural gas transmission line in Victoria, Australia. CGI and its affiliates are pursuing additional gas projects in Canada and Latin America.

Engage Energy US, L.P. and Engage Energy Canada, L.P. (together, "Engage") handle unregulated natural gas and power marketing for Coastal in North America. Engage provides wholesale energy services to natural gas and power clients and marketing services to various Coastal segments, including refining, chemicals and exploration and production. Engage was formed in February 1997 and is a joint venture of Coastal (50%) and Westcoast Energy Inc. (50%), a major Canadian natural gas company. In 1998, Engage had physical sales volumes averaging 7 Bcf per day of natural gas, and annual power sales of 36 million megawatt hours.

REGULATIONS AFFECTING GAS SYSTEMS

General

Under the NGA, the FERC has jurisdiction over ANR Pipeline, Colorado, WIC, ANR Storage and Great Lakes as to rates and charges for the transportation, storage and balancing of natural gas, the construction of new facilities, the extension or abandonment of service and facilities, accounts and records, depreciation and amortization policies and certain other matters. In addition, the FERC has certificate authority over gas sales for resale in interstate commerce, but under Order 636, has determined that it will not regulate pipeline sales rates. Additionally, the FERC has asserted rate- regulation (but not certificate regulation) over gathering services provided by interstate pipeline companies such as Colorado. ANR Pipeline, Colorado, WIC, ANR Storage and Great Lakes hold certificates of public convenience and necessity issued by the FERC covering their jurisdictional facilities, activities and services. Certain other affiliates of the Company are subject to the jurisdiction of state regulatory commissions in states where their facilities are located.

ANR Pipeline, Colorado, WIC, ANR Storage and Great Lakes are also subject to regulation with respect to safety requirements in the design, construction, operation and maintenance of their interstate gas transmission and storage facilities by the Department of Transportation. Additionally, subsidiaries of the Company are subject to similar safety requirements from the Department of Labor's Occupational Safety and Health Administration related to their processing plants. Operations on United States government land are regulated by the Department of the Interior.

Rate Matters

Certain of the Company's subsidiaries' service options are subject to rate regulation by the FERC. Under the NGA, these subsidiaries must file with the FERC to establish or adjust their services and their rates. The FERC may also initiate proceedings to determine whether these subsidiaries' rates are "just and reasonable."

On January 31, 1996, the FERC issued a "Statement of Policy and Request for Comments" ("Policy"). Under this Policy, (i) a pipeline and a customer are allowed to negotiate a contract which provides for rates and charges that exceed the pipeline's posted maximum tariff rates, provided that the customer agreeing to such negotiated rates has the ability to elect to receive service at the pipeline's posted maximum rate (known as a "recourse rate"), and (ii) a pipeline must also make subsequent tariff filings each time the pipeline negotiates a rate for service which is outside of the minimum and maximum range for the pipeline's cost-based recourse rates. To implement this Policy, a pipeline must make an initial tariff filing with the FERC to indicate that it intends to contract for services under this Policy. CIG has received FERC authority to enter into negotiated rate transactions. Separately, the FERC has determined that pipelines who seek to include negotiated rate transactions in the discount adjustment used to calculate their rates must file tariff sheets demonstrating that existing customers who purchase service under the pipeline's cost-of-service rates will not be harmed by negotiated rate discounts.

On July 29, 1998, the FERC issued a "Notice of Proposed Rulemaking," in which the FERC has proposed a number of further significant changes to the industry, including, among other things, removal of price caps in the short-term market (less than one year), capacity auctions, changed reporting obligations, the ability to negotiate terms and conditions of all services, elimination of the requirement of a matching term cap on the renewal of existing contracts, and a review of its policies for approving capacity construction. On the same day, the FERC also issued a "Notice of Inquiry" soliciting industry input on various matters affecting the pricing of long-term service and certificate pricing in light of changing market conditions. The due date for comments on both of these matters has been rescheduled twice and is currently scheduled for April 22, 1999. The FERC has indicated that it may consider both proposals together inasmuch as they raise several common issues.

On May 30, 1997, WIC filed with the FERC to increase its rates by approximately $5.7 million annually. On June 27, 1997, the FERC accepted the filing effective as of December 1, 1997, subject to refund. After the filing of testimony by WIC and other parties on July 2, 1998, WIC filed a settlement offer which, if approved, would have resolved all of the issues in the case. That settlement, however, was remanded to the Administrative Law Judge ("ALJ") because of opposition to the settlement by certain parties. In response to the remand, WIC and the parties have resubmitted a settlement offer which contains the same substantive provisions, but provides for the Commission to approve the settlement for some, if not all, parties, with the "severed" parties being able to litigate their issues in the case. The ALJ has certified the new settlement to the FERC, and dates for filing briefs on the new settlement have been established.

Certain other regulatory issues remain unresolved among CIG, ANR Pipeline, ANR Storage Company and WIC, their customers, their suppliers and the FERC. The Company has made provisions which represent management's assessment of the ultimate resolution of these issues. As a result, the Company anticipates that these regulatory matters will not have a material adverse effect on its consolidated financial position or results of operations. While the Company estimates the provisions to be adequate to cover potential adverse rulings on these and other issues, it cannot estimate when each of these issues will be resolved.

REFINING, MARKETING AND DISTRIBUTION, AND CHEMICALS

The Company has subsidiary operations involved in the purchase, transportation and sale of refined products, crude oil, condensate and natural gas liquids; the operation of refineries and chemical plants; the sale at retail of gasoline, petroleum products and convenience items; petroleum product terminaling and marketing of crude oil and refined products worldwide.

Refining

Subsidiaries of the Company operated their refineries at 85% of average combined capacity in 1998 compared to 89% in 1997 and at 97% in 1996. The aggregate sales volumes (millions of barrels) of Coastal's wholly owned refineries for the three years ended December 31, 1998 were 154.4 (1998), 160.7 (1997) and 160.4 (1996). Of the total refinery sales in 1998, 27% was gasoline, 43% was middle distillates, such as jet fuel, diesel fuel and home heating oil, and 30% was heavy industrial fuels and other products.

At December 31, 1998, average daily throughput and storage capacity at the Company's wholly owned refineries are set forth below:

<TABLE>
<CAPTION>

Refinery	Location	Daily Capacity (Barrels)	Average Daily Throughput (Barrels) 1998	1997	Storage Capacity (Barrels)
<S>		<C>	<C>	<C>	<C>
Aruba	Aruba	225,000	162,300	180,600	15,300,000
Corpus Christi	Corpus Christi, Texas	100,000	88,600	87,100	7,100,000
Eagle Point	Westville, New Jersey	140,000	140,400	133,400	10,600,000
Mobile	Mobile, Alabama	18,000	10,400	12,900	600,000
	Total	483,000	401,700	414,000	33,600,000

</TABLE>

In addition, Coastal's international operations include a minority interest, through a foreign subsidiary, in a refinery located in Hamburg, Germany which has a refining capacity of 100,000 barrels per day and a storage capacity of 1,800,000 barrels for crude oil and 5,200,000 barrels for products.

The Company's refineries produce a full range of petroleum products ranging from transportation fuels to paving asphalt. The refineries are operated to produce the particular products required by customers within each refinery's geographic area. In 1998, the products emphasized included premium gasolines and products for specialty markets such as petrochemical feedstocks, aviation fuels and asphalt.

On July 30, 1998, the Company, through a subsidiary, entered into an agreement with a subsidiary of Petroleos Mexicanos, Mexico's national oil company, for the supply of up to 100,000 barrels per day ("bpd") of crude oil to support an upgrade of the Company's Aruba refinery. The upgrade at the refinery will include the installation of a new 30,000 bpd delayed coking unit and other modifications aimed at increasing the refinery's heavy crude refining and conversion capacity to approximately 280,000 bpd. The upgrade is projected to be in service during the first half of the year 2000.

Chemicals

Coastal Chem, Inc. ("Coastal Chem"), a Coastal subsidiary, operates a plant near Cheyenne, Wyoming, which produces anhydrous ammonia, ammonium nitrate, nitric acid, liquid carbon dioxide and urea for use as agricultural fertilizers, livestock feed supplements, blasting agents and various other industrial applications. This plant has the capacity to produce 550 tons per day of anhydrous ammonia, 875 tons per day of ammonium nitrate, 275 tons per day of urea, 700 tons per day of nitric acid and 400 tons per day of liquid carbon dioxide. Coastal Chem also owns a plant at Table Rock, Wyoming, which has a production capacity of 150 tons of liquid fertilizer per day. In addition, Coastal Chem operates a low density ammonium nitrate ("LoDAN(R)") facility in Battle Mountain, Nevada, which has the capacity to produce 400 tons per day. The LoDAN(R) product is used primarily as a blasting agent in surface mining.

Coastal Chem also operates an integrated methyl tertiary butyl ether ("MTBE") plant in Cheyenne, Wyoming, with a production capacity of 4,200 barrels per day. MTBE is a gasoline additive which adds oxygen and boosts octane of the blended mixture.

Coastal's St. Helens chemical plant, located in St. Helens, Oregon, has the capacity to produce 300 tons per day of anhydrous ammonia, 370 tons per day of urea and 185 tons per day of urea/ammonium nitrate solutions. Approximately 55% of the plant's production is sold as industrial products and 45% as agricultural products.

Sales volumes for Coastal Chem and St. Helens for the three years ended December 31, 1998, are set forth below (thousands of tons):

<TABLE>
<CAPTION>

<S>	1998 <C>	1997 <C>	1996 <C>
Agricultural Sales	346	340	276
Industrial Sales	550	566	608
MTBE	210	223	204
Total	1,106	1,129	1,088

</TABLE>

Coastal Chem and the St. Helens plant compete with many nitrogen and MTBE producers across the United States and Canada. The Company's strengths are product quality, service, and dependability. Coastal Chem and the St. Helens plant produce commodity products with strong price competition from producers worldwide.

In November 1998, the Company temporarily suspended operations at its petrochemical facility in Montreal East, Quebec, Canada. Operations will be resumed when supply/demand conditions provide the necessary economic support. The petrochemical facility has the capacity to produce 330,000 tons per year of paraxylene, a component used in the manufacturing of polyester fibers and containers. Production (in tons) shipped and sold from the plant for the three years ended December 31, 1998, was 203,500 (1998), 338,400 (1997) and 289,100 (1996).

The Company's 660 tons per day anhydrous ammonia facility located in Oyster Creek, Texas began operation in the first quarter of 1998. Production (in tons) sold from the facility for the year ended December 31, 1998, was 45,000. This plant is located adjacent to and supplies a number of major chemical facilities.

Marketing and Distribution

Refined Products Marketing. Sales volumes for distribution activities of Coastal subsidiaries, including products from Company refineries and purchases from other suppliers, for the three years ended December 31, 1998, are set forth below (thousands of barrels):

Type of Sale	1998	1997	1996
Company Produced Refined Products	154,427	160,703	160,383
Refined Products Purchased from Others	131,508	101,495	130,240
Natural Gas Liquids	14,292	16,593	16,205
Total	300,227	278,791	306,828

Subsidiaries of the Company market refined products and liquefied petroleum gas at wholesale in 32 states plus Canada and Panama through 223 terminals. Coastal Refining & Marketing, Inc. serves customers primarily in the Midwest, Mississippi Valley and the Southwest through 168 product and liquefied petroleum gas terminals in 23 states. On the Gulf and East Coasts, divisions of Coastal Refining & Marketing, Inc. serve home, industry, utility, defense and marine energy needs. In 1998, these divisions' sales volumes were 67.6 million barrels, which accounted for approximately 23% of the total marketing and distribution sales. International subsidiaries that acquire feedstocks for the refineries and products for the distribution system are located in Aruba, London and Singapore.

A subsidiary of Coastal leases petroleum storage facilities located at the former U.S. naval base at Subic Bay in the Philippines. Coastal is leasing 304 acres of land, with 68 individual storage tanks totaling 2.4 million barrels of storage, most of which are underground, and 40 miles of pipeline connecting the terminal with other facilities within the Subic Bay Freeport Zone. A joint venture between a Coastal subsidiary and the Petroleum Authority of Thailand rehabilitated the petroleum products pipeline between the Subic Bay Freeport Zone and the Clark Special Economic Zone (formerly Clark Air Force Base), along with a petroleum storage facility in the Clark Special Economic Zone. Both facilities are used to support the joint venture's marketing activities in the Philippines.

Coastal Baltica Holding Company Ltd., a joint venture in which a Coastal subsidiary is a 50% partner, commenced operations at its terminal and new port facilities near Tallinn, Estonia on the Baltic Sea in 1996. The terminal operation handled imports and exports of approximately 13.5 million barrels of petroleum products in 1998, primarily from Russia and the former republics of the Soviet Union to markets in Europe, North and South America and the Caribbean.

The Company, through Coastal Mart, Inc. and branded marketers, conducts retail marketing, using the C-MART(R), C and Design and/or COASTAL(R) trademarks, in 34 states and Aruba through approximately 1,550 Coastal branded outlets, with 414 of those outlets operated by the Company. Fleet fueling operations include 23 outlets in Texas and 6 in Florida.

Coastal Unilube, Inc., based in West Memphis, Arkansas, blends, packages and distributes lubricants and automotive products under the COASTAL(R), C and Design and other trademarks through 14 warehouses servicing customers in 45 states, plus the District of Columbia, Puerto Rico and 20 foreign countries.

Transportation. The Company's transportation facilities include petroleum liquids pipelines, tank cars, tankers, tank trucks and barges. Coastal operates over 1,700 miles of pipeline for gathering and transporting an average of 223,123 barrels daily of crude oil, condensate, natural gas liquids and refined products. These pipelines include 304 miles of crude oil pipelines, 718 miles of refined products pipelines, and 582 miles of natural gas liquids pipelines, all located principally in Texas, in which the Company has approximately a 32% ownership interest. Coastal has a 50% ownership in 13 miles of refined products pipelines located in New Jersey and New York. Coastal also has a 33.3% interest in 80 miles of refined products pipelines in New Jersey and 35 miles of crude pipelines in Louisiana. In 1998, throughput of crude oil pipelines averaged 15,323 barrels per day, compared to 13,117 barrels per day in 1997 and 14,323 barrels per day in 1996. In 1998, throughput of refined products and natural gas liquid pipelines averaged 207,800 barrels per day, compared to 216,204 barrels per day in 1997 and 215,897 barrels per day in 1996.

The marine transportation fleet at December 31, 1998 consisted of 15 tug boats, 19 oil barges, 4 owned tankers and 5 time-chartered tankers.

Competition

The petroleum industry is highly competitive in the United States and throughout most of the world. The Company's subsidiary operations involved in refining, marketing and distribution of petroleum products and chemicals compete with other industries in supplying the energy needs of various types of consumers. Principle factors affecting sales are price, location and service. Overall performance is impacted by industry margins, and supply and demand for both feedstocks and finished products.

EXPLORATION AND PRODUCTION

Gas and Oil Properties

Coastal subsidiaries are engaged in gas and oil exploration, development and production operations principally in California, Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Texas, Utah, West Virginia, Wyoming and offshore in the Gulf of Mexico. In addition, Coastal subsidiaries have exploration and production rights in Argentina, Australia, Brazil, Hungary, Indonesia and Peru.

In 1998, the Company's domestic exploration and production operations sold approximately 10% of all the gas it produced to certain of Coastal's wholly owned natural gas system subsidiaries and approximately 82% to Engage. The Company's domestic operations also make short-term gas sales directly to industrial users and distribution companies to increase utilization of its excess current gas production capacity. Oil is sold primarily under short-term contracts at field prices posted by the principal purchasers of oil in the areas in which the producing properties are located.

Acreage held under gas and oil mineral leases as of December 31, 1998 is summarized as follows:
<TABLE>
<CAPTION>

Area	Undeveloped Gross	Undeveloped Net	Developed Gross	Developed Net
	(Thousands of Acres)			
<S>	<C>	<C>	<C>	<C>
Exploration and Production				
United States (Domestic)				
Onshore	542	430	1,059	573
Offshore	453	328	240	151
Total Domestic	995	758	1,299	724
International				
Argentina	9,850	2,462	-	-
Australia	1,770	614	-	-

Brazil	131	52	-	-
Hungary	568	568	-	-
Indonesia	1,374	443	-	-
Peru	2,813	1,407	-	-
Total International	16,506	5,546	-	-
Total Exploration and Production	17,501	6,304	1,299	724
Natural Gas Systems				
Domestic Onshore	-	-	263	259
Total Acreage	17,501	6,304	1,562	983

</TABLE>

The domestic net developed acreage is concentrated principally in Texas (30%), Utah (31%), offshore Gulf of Mexico (15%), Colorado (13%) and Kansas (5%). Approximately 11%, 8% and 11% of the Company's total domestic net undeveloped acreage is under leases that have minimum remaining primary terms expiring in 1999, 2000 and 2001, respectively.

Productive wells as of December 31, 1998 are as follows (domestic):

<TABLE>
<CAPTION>

Type of Well	Gross	Net
<S>	<C>	<C>
Exploration and Production		
Oil	611	362
Gas	2,465	1,640
Total Exploration and Production	3,076	2,002
Natural Gas Systems		
Oil	9	8
Gas	777	773
Total Natural Gas Systems	786	781
Total	3,862	2,783

</TABLE>

Exploration and Drilling

During 1998, Coastal's domestic subsidiaries participated in drilling 212 gross wells, 158.3 net wells, to the Company's interest. Coastal's participation in wells drilled in the three years ended December 31, 1998, is summarized as follows:

<TABLE>
<CAPTION>

Exploration and Production	1998		1997		1996	
Exploratory Wells	Gross	Net	Gross	Net	Gross	Net

<S>	<C>	<C>	<C>	<C>	<C>	<C>
Oil......................	-	-	-	-	-	-
Gas......................	7	5.1	8	3.3	7	2.3
Dry Holes................	7	3.4	5	2.9	4	1.9
	14	8.5	13	6.2	11	4.2
Development Wells						
Oil......................	4	2.9	2	1.7	5	1.6
Gas......................	186	139.5	128	96.7	80	56.8
Dry Holes................	2	1.4	4	2.2	3	1.4
	192	143.8	134	100.6	88	59.8
Natural Gas Systems						
Development Wells						
Oil......................	-	-	-	-	2	2.0
Gas......................	6	6.0	3	3.0	8	8.0
Dry Holes................	-	-	-	-	-	-
	6	6.0	3	3.0	10	10.0
Total..........................	212	158.3	150	109.8	109	74.0

</TABLE>

Wells in progress as of December 31, 1998 are as follows (domestic):

<TABLE>
<CAPTION>

Type of Well	Gross	Net
<S>	<C>	<C>
Exploration and Production		
Exploratory..	3	2.1
Development..	23	18.9
Total Exploration and Production...	26	21.0
Natural Gas Systems		
Exploratory..	-	-
Development..	-	-
Total Natural Gas Systems..	-	-
Total..	26	21.0

</TABLE>

Coastal's domestic exploration and development operations are focused on three core areas: the Texas Coastal Plain, the Gulf of Mexico and the Rocky Mountains.

In 1998, the Texas Coastal Plain continued its significant contribution with net average production of approximately 220 MMcf per day for the second consecutive year. Redevelopment of the Jeffress Field, beginning in 1995, led the way to achieving this current production level. Field production grew from its 20 MMcf per day 1995 level to a 1998 average of 160 MMcf per day. The Company has acquired several additional properties in the immediate Jeffress area, and the redevelopment of these properties has added net equivalent reserves of 235 Bcf.

At the end of 1998, Coastal held interests in 145 blocks and 58 platforms in the Gulf of Mexico. Net annual 1998 natural gas production increased to 191 MMcf per day from 1997's average of 119 MMcf per day. Oil and condensate production averaged 7,511 barrels per day in 1998 compared to an average level of 3,557 barrels per day in 1997. The Company operates 41 of the platforms as compared with 36 at the end of the previous year.

In November 1998, Coastal Oil & Gas Corporation ("COGC") acquired interests in 21 oil and gas producing fields and approximately 305,000 acres of producing and non-producing leasehold interests in the Uinta Basin of Utah and the Piceance Basin of Colorado - two gas basins in the Rocky Mountains. Average net gas production for the Rocky Mountain area was 79 MMcf per day in 1998 as compared with 67 MMcf per day in 1997.

In 1998, Coastal positioned itself for active exploration and development programs in Canada, Brazil and Australia to be undertaken in 1999. In Canada, Coastal will seek to develop or acquire production to support its shipping commitment on the Alliance Pipeline. In Australia, Coastal plans to begin exploration of two operated leases off the continent's northern coast in the Timor Sea. In October 1998, COGC contracted with Petroleo Brasileiro S.A., the national oil company of Brazil, to participate in the exploration and production of two offshore concession blocks in the Camamu Basin.

Gas and Oil Production

Natural gas production during 1998 averaged 616 MMcf daily, compared to 540 MMcf daily in 1997. Production from non-pipeline-owned wells averaged 509 MMcf daily in 1998, compared to 436 MMcf daily in 1997. Crude oil, condensate and natural gas liquids production averaged 15,401 barrels daily in 1998, compared to 13,736 barrels daily in 1997.

The following table shows gas, oil, condensate and natural gas liquids production volumes attributable to Coastal's domestic interest in gas and oil properties for the three years ended December 31, 1998:

<TABLE>
<CAPTION>

Year	Gas (MMcf)	Oil (Thousands of Barrels)	Condensate (Thousands of Barrels)	Natural Gas Liquids (Thousands of Barrels)
<S>	<C>	<C>	<C>	<C>
Exploration and Production				
1998	185,732	3,725	1,633	220
1997	159,127	3,425	1,224	308
1996	129,149	3,885	853	324
Natural Gas Systems				
1998	39,058	44	-	-
1997	38,135	57	-	-
1996	39,405	23	-	-

</TABLE>

Many of Coastal's domestic gas wells are situated in areas near, and are connected to, its gas systems. In other areas, gas production is sold to pipeline companies and other purchasers.

Generally, Coastal's domestic production of crude oil, condensate and natural gas liquids is purchased at the lease by its marketing and refinery affiliates. Some quantities are delivered via Coastal's gathering and transportation lines to its refineries, but most quantities are redelivered to Coastal through various exchange agreements.

The following table summarizes sales price and production cost information for domestic exploration and production operations during the three years ended December 31, 1998:

	1998	1997	1996
Average sales price:			
Gas - per Mcf	$ 1.95	$ 2.40	$ 2.19
Oil - per barrel	11.87	18.01	20.28
Condensate - per barrel	11.08	18.37	20.76
Natural Gas Liquids - per barrel	15.24	28.41	21.74
Average production cost per unit (equivalent Mcf)	0.41	0.49	0.46

Company-Owned Reserves

Coastal's estimated domestic proved reserves of crude oil, condensate and natural gas liquids at December 31, 1998, as estimated by the Company and reviewed by Huddleston, the Company's independent engineers, were 52.3 million barrels, compared to 40.1 million barrels at the end of 1997. Proved gas reserves as of December 31, 1998, net to Coastal's interest, were estimated by the Company and reviewed by Huddleston to be 2,527.1 Bcf compared to 1,752.5 Bcf as of December 31, 1997. All of the 1997 proved reserves were estimated by Huddleston. For the fourth consecutive year, Coastal added in 1998 proved reserves that were more than triple the production volumes.

For information as to Company-owned reserves of oil and gas, see "Supplemental Information on Oil and Gas Producing Activities (Unaudited)" as set forth in Item 14(a)1 hereof.

Competition

In the United States, the Company competes with major integrated oil companies and independent oil and gas companies for suitable prospects for oil and gas drilling operations. The availability of a ready market for gas discovered and produced depends on numerous factors frequently beyond the Company's control. These factors include the extent of gas discovery and production by other producers, crude oil imports, the marketing of competitive fuels, and the proximity, availability and capacity of gas pipelines and other facilities for the transportation and marketing of gas. The production and sale of oil and gas is subject to a variety of federal and state regulations, including regulation of production levels.

Regulation

In all states in the United States in which Coastal engages in oil and gas exploration and production, its activities are subject to regulation. Such regulations may extend to requiring drilling permits, the spacing of wells, the prevention of waste and pollution, the conservation of natural gas and oil, and various other matters. Such regulations may impose restrictions on the production of natural gas and crude oil by reducing the rate of flow from individual wells below their actual capacity to produce. Likewise, oil and gas operations on all federal lands are subject to regulation by the Department of the Interior and other federal agencies.

COAL

Through the operations of Coastal Coal Company, LLC (formerly ANR Coal

Company, LLC) and its affiliates (collectively "Coastal Coal") in the eastern United States, the Company produces and markets high quality bituminous coal from reserves in Kentucky, Virginia and West Virginia. In addition, Coastal Coal leases interests in its reserves to unaffiliated producers and markets third-party coal through brokerage sales operations.

In December 1996, the Company sold its western coal operations, which consisted of the Utah mines, for approximately $610 million in cash to a limited liability company jointly owned by subsidiaries of Atlantic Richfield Co. and ITOCHU. See Item 3 and Notes 10 and 16 of the Notes to Consolidated Financial Statements included herein.

At December 31, 1998, coal properties consisted of the following:

<TABLE>
<CAPTION>

	Coal Holdings (Acres)					Clean,
	Owned			Leased		Recoverable
				Exchanged	Total	Tons
	Fee	Mineral	Surface	(Net)	Acres	(Millions)(1)
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Kentucky........................	14,121	76,131	2,454	30,590	123,296	198
Virginia........................	24,378	36,909	2,090	16,545	79,922	166
West Virginia...................	334	56,097	7,031	90,662	154,124	171
Total.....................	38,833	169,137	11,575	137,797	357,342	535

<FN>
----

(1) Based on a 65% recovery rate.
</FN>
</TABLE>

At December 31, 1998, the Company controlled approximately 535 million recoverable tons of bituminous coal reserves and resources. Production in 1998 from Coastal Coal's reserves totaled 10.8 million tons, of which 7.0 million tons were produced from captive operations and 3.8 million tons were produced by lessees under royalty agreements. In its eastern captive operations, Coastal Coal contracts with independent mine operators to deliver coal to Company owned and operated processing and loading facilities for the majority of its production. The remaining production is derived from nine company mines operated by Coastal Coal in Virginia, Kentucky and West Virginia. Captive production and clean coal processed from these mines totaled 3.5 million tons in 1998.

Captive sales by Coastal Coal were 8.2 million tons in 1998, as compared to 7.2 million tons in 1997. Brokerage sales in which the Company receives a commission totaled 0.8 million tons for both 1998 and 1997.

In 1998, approximately 78% of the captive sales were to domestic utilities, 9% of the sales were to domestic industrial customers and 13% of the sales were to export markets in Europe, Canada and South America. Additionally, 0.3 million tons of Coastal Coal's production were sold to domestic and foreign metallurgical markets. Of the total 1998 tonnage sold, 5.7 million tons (70%) were sold under long-term contracts. At December 31, 1998, the weighted average remaining life of these contracts was 40 months.

The Company had approximately 10.3 million tons of annual production capacity at December 31, 1998 from four coal preparation plants and seven loading facilities it owns and operates in the central Appalachian coal fields.

In addition to its bituminous coal operations, the Company controls overriding royalty interests in approximately 425 million tons of lignite reserves in North Dakota. Production from these reserves in 1998 totaled 9.7 million tons.

The Company, through its captive operations, leasing programs and brokerage activities, participates in all aspects of the eastern bituminous coal industry and is a significant competitor in international metallurgical coal markets. A significant portion of its reserves are low-sulfur, compliance coal which will allow the Company to remain a major supplier of steam coal to domestic utilities under the Clean Air Act Amendments of 1990.

The Company competes with a large number of coal producers and land holding companies in the eastern United States. The principal factors affecting the Company's coal sales are price, quality (BTU, sulfur and ash content), royalty rates, employee productivity and rail freight rates.

POWER

Coastal Power Company ("Coastal Power") and certain of its affiliates develop, operate and own various equity interests in cogeneration and independent power projects. The projects produce and sell electrical energy and, in the case of cogeneration projects, thermal energy as well. Affiliates of Coastal Power have interests in five operating domestic cogeneration projects and nine foreign operating independent power projects, as well as interests in other projects in various stages of construction and development.

Capitol District Energy Center Cogeneration Associates ("CDECCA") owns a combined-cycle cogeneration facility with a capacity of approximately 56 megawatts, located in Hartford, Connecticut. An affiliate of Coastal Power owns a 50% equity interest in CDECCA and is the project manager and Coastal Technology, Inc. ("CTI"), a Coastal subsidiary, is the operator of the plant. Electricity from the facility is sold to a local utility under a long-term contract. Gas supply is provided to the cogeneration plant by other Coastal affiliates. Thermal energy from the plant is sold both to a local heating and cooling supplier in the city of Hartford and an affiliate of the equity partner of CDECCA.

Affiliates of Coastal Power include the managing partner and 50% ownership of a combined-cycle cogeneration plant at Coastal's Eagle Point, New Jersey refinery. The plant has a capacity of approximately 225 megawatts. Power from the plant is sold to a local utility and Coastal's refinery under long-term contracts. Steam from the plant is also sold to the refinery under a long-term contract. Gas supply and transportation is provided to the cogeneration plant by other Coastal affiliates. CTI is the operator of the cogeneration plant.

Fulton Cogeneration Associates, L.P. ("Fulton") leases a cogeneration facility with a capacity of approximately 47 megawatts, located in Fulton, New York. This partnership is 100% owned by Coastal Power and another Coastal subsidiary. Electricity from this project is sold to a New York utility and to an affiliate of Fulton that resells into the wholesale market. Thermal energy is sold to a local confections manufacturer adjacent to the project, also under a long-term contract. CTI is the operator of the cogeneration plant. In 1998, Coastal completed the restructuring of the power purchase agreement for the Fulton plant.

Coastal, through direct and indirect subsidiaries, has a 20.4% equity interest in the Midland Cogeneration Venture Limited Partnership, a 1,370 megawatt gas-fired cogeneration project in Michigan, which is the largest cogeneration facility in the United States. Power from the project is sold to a local utility and the project's thermal host under long-term contracts. Steam from the project is also sold to the thermal host and its affiliate under long-term contracts. Coastal's affiliates provide gas supply and transmission services for a portion of the project's fuel requirements.

In March 1999, Fulton acquired the 79.6-megawatt Rensselaer combined-cycle, cogeneration facility near Albany, New York. The Rensselaer facility is located on a site leased from the Albany Port District Commission. The facility is natural gas fired, but is capable of utilizing No. 2 fuel oil. Fulton will manage the facility and CTI will operate the facility.

Compania de Electricidad de Puerto Plata, S.A. ("CEPP") owns an independent power project in Puerto Plata, Dominican Republic. Coastal Power International Ltd. owns a 48.3% equity interest in CEPP. Two unrelated parties own the remaining equity in CEPP. The project has a total capacity of 66.5 megawatts of which 50 megawatts are barge mounted and 16.5 megawatts are land based. An affiliate of Coastal Power is involved in arranging the fuel for the project and another affiliate operates the project pursuant to a contract with CEPP. The electrical energy is sold to the national electric utility of the Dominican Republic under a long-term contract.

Coastal Nejapa Ltd. and other affiliates lease an independent power project near Apopa, El Salvador. The heavy-fuel-oil plant has a capacity of approximately 144 megawatts. Coastal Power, through its affiliates, currently receives approximately 86.6% of the distributable cash flow and an unrelated investor receives the remainder. Coastal

affiliates provide fuel for this project and another affiliate operates the project pursuant to a long-term contract. The electrical energy is sold to the national electric utility of El Salvador under a long-term contract.

Coastal Power Guatemala, a wholly owned subsidiary of Coastal Power, effectively owns a 46% interest of Central Generadora Electrica San Jose, Limitada, with the remainder of the project held by parties unrelated to Coastal Power. Central Generadora Electrica San Jose, Limitada was formed to develop, construct, own, and operate a 120-megawatt coal-fired power plant near San Jose, Guatemala. Construction of the plant commenced in 1997 and is expected to be completed in the first quarter of 2000. The power from the plant will be sold to a Guatemalan utility under a long-term contract.

In late 1997, a subsidiary of Coastal Power won the bid to develop and operate a 50.9 megawatt (net) heavy fuel oil project in Tipitapa, Nicaragua. The Coastal Power subsidiary owns a 60% equity interest in the project, with Nicaraguan partners owning the remaining 40% interest. Operations commenced in the first quarter of 1999, with power from the project being sold to the national utility company under a long-term contract. An affiliate of Coastal Power operates the project pursuant to a long-term contract.

In January 1999, a consortium comprised of a subsidiary of Coastal Power and Hydro-Quebec International Inc. purchased a 49% interest in Empresa de Generation Electrica Fortuna, S.A. ("Fortuna"), with the Coastal Power subsidiary holding approximately 49.9% of the acquired interest in Fortuna. Fortuna owns and operates a 300-megawatt hydroelectric plant located on the Chiriqui River in the highlands region of Panama's Chiriqui province. The plant began operating in 1983 and represents approximately one-third of Panama's total installed capacity.

Coastal Wuxi Power Ltd., an affiliate of Coastal Power, together with two Chinese partners, formed a Sino-foreign joint venture company to own, construct, and operate a simple-cycle, diesel-fired peaking plant. The project has a capacity of approximately 40 megawatts and is located in Wuxi City, Province of Jiangsu, The People's Republic of China. Coastal Wuxi Power Ltd. owns a 60% equity interest in the joint venture. The project commenced the sale of electrical energy in the first quarter of 1996. Power generated by the plant is sold to the local utility under a long-term contract.

Coastal Suzhou Power Ltd., a subsidiary of Coastal Power, together with a Chinese partner, formed a Sino-foreign joint venture to develop, construct, own, and operate an independent power project. The project has a capacity of approximately 76 megawatts and is located in Suzhou City, Province of Jiangsu, The People's Republic of China. Coastal Suzhou Power Ltd. owns a 60% equity interest in the joint venture. The project commenced the sale of electrical energy in the fourth quarter of 1996. Power generated by the plant is sold under a long-term contract.

Coastal Gusu Heat & Power Ltd., an affiliate of Coastal Power, together with two Chinese partners, formed a Sino-foreign joint venture to develop, construct, own and operate a 24 megawatt cogeneration plant adjacent to the existing Suzhou City 76 megawatt plant. Coastal Gusu Heat & Power Ltd. owns a 60% equity interest in the joint venture. The project commenced commercial operation in November 1998. Power generated by the plant is sold to the local utility under a long-term contract.

In December 1995, Coastal Nanjing Power Ltd., a subsidiary of Coastal Power, together with two Chinese partners, formed a Sino-foreign joint venture to develop, construct, own and operate an independent power project. The project has a capacity of approximately 72 megawatts and is located in Nanjing City, Jiangsu Province, The People's Republic of China. Coastal Nanjing Power Ltd. owns an 80% equity interest in the joint venture. The project commenced the sale of electrical energy in July 1997. The power is sold to the local utility under a long-term contract.

A subsidiary of Coastal Power is currently entitled to approximately 90% of the profits and cash flows of a 140 megawatt natural gas-fired power plant being constructed in Quetta, Pakistan, with an unrelated entity entitled to the remaining 10%. The power from the project will be sold to a national utility under a long-term contract. The plant should be in service by mid year 1999.

A subsidiary of Coastal Power has a financial stake of approximately 93% of a 125-megawatt heavy-fuel oil project in Farouqabad, Pakistan. The power from the project will be sold to a national utility under a long-term contract, with operations expected to commence by mid year 1999.

In September 1998, Coastal Power Khulna Ltd., a subsidiary of Coastal Power, acquired a 66.7% interest in a 110- megawatt, fuel oil-fired power plant located in Khulna in southwestern Bangladesh. Commercial operation of the Khulna project began in October 1998. The power generated by the project is being sold to the national utility under a long-term contract.

Competition

Coastal is subject to competition with other energy organizations and utilities seeking to develop and acquire independent power operations. Coastal and many other power producers are concentrating their efforts in the United States and abroad. International competition continues to increase as the world market for independent power production develops and power purchasers employ competitive bidding for project awards. In the United States and international locations, the sale of power and the operation of power cogeneration facilities are regulated by the applicable laws, rules and regulations of the respective governments and agencies having jurisdiction. Many U.S. states are restructuring their applicable laws, rules and regulations. This restructuring is likely to result in new development opportunities in the U.S. and increased competition in response to such opportunities.

COMPETITION

Coastal and its subsidiaries are subject to competition. In all the Company's business segments, competition is based primarily on price with factors such as reliability of supply, service and quality being considered. The natural gas systems; refining, marketing and distribution, and chemicals; exploration and production; coal; and power subsidiaries of Coastal are engaged in highly competitive businesses against competitors, some of which have significantly larger facilities and market share. See also the discussion of competition under "Natural Gas Systems," "Refining, Marketing and Distribution, and Chemicals," "Exploration and Production," "Coal" and "Power" herein.

ENVIRONMENTAL

The Company's operations are subject to extensive and evolving federal, state and local environmental laws and regulations. Compliance with such laws and regulations can be costly. Additionally, governmental authorities may enforce the laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties and remediation requirements.

The Company spent approximately $13 million in 1998 on environmental capital projects and anticipates capital expenditures of approximately $44 million in 1999 in order to comply with such laws and regulations. The majority of the 1999 expenditures is attributable to projects at the Company's refining, chemical and terminal facilities. The Company currently anticipates capital expenditures for environmental compliance for the years 2000 through 2002 of $20 million to $40 million per year.

The Comprehensive Environmental Response, Compensation and Liability Act, also known as "Superfund," imposes liability for the release of a "hazardous substance" into the environment. Superfund liability is imposed without regard to fault and even if the waste disposal was in compliance with the then current laws and regulations. With the joint and several liability imposed under Superfund, a potentially responsible party ("PRP") may be required to pay more than its proportional share of such costs. Certain subsidiaries of the Company and a company in which Coastal owns a 50% interest have been named as a PRP in several Superfund waste disposal sites. At the 11 sites for which there is sufficient information, total cleanup costs are estimated to be approximately $620 million, and the Company estimates its pro-rata exposure, to be paid over a period of several years, is approximately $7.5 million and has made appropriate provisions. At nine other sites, the Environmental Protection Agency ("EPA") is currently unable to provide the Company with an estimate of total cleanup costs and, accordingly, the Company is unable to calculate its share of those costs. Additionally, certain subsidiaries of the Company have been named as PRPs in two state sites. At one site, the North Carolina Department of Health, Environment and Natural Resources has estimated the total cleanup costs to be approximately $50 million, but the Company believes the subsidiary's activities at this site were de minimis. At the second state site,

the Florida Department of Environmental Protection has demanded reimbursement of its costs, which total $100,000, and suitable remediation. There is not sufficient information to estimate the remedial costs or the Company's pro-rata exposure at this site.

In Michigan, where ANR Pipeline has extensive operations, the Environmental Response Act requires individuals (including corporations) who have caused contamination to remediate the contamination to regulatory standards. Owners or operators of contaminated property who did not cause the contamination are not required to remediate the contamination, but must exercise due care in their use of the property so that the contamination is not exacerbated and the property does not pose a threat to human health. ANR Pipeline estimates that its costs to comply with the Michigan regulations will be approximately $10 million, which will be expended over a period of several years and for which appropriate provisions have been made.

Future information and developments, including legislative and enforcement developments, will require the Company to continually reassess the expected impact of these environmental matters. However, the Company has evaluated its total environmental exposure based on currently available data, including its potential joint and several liability, and believes that compliance with all applicable laws and regulations will not have a material adverse impact on the Company's consolidated financial position or results of operations.

OTHER DEVELOPMENTS

Natural Gas

In March 1999, Coastal announced the development of the proposed Gulfstream Natural Gas System ("Gulfstream System"), consisting of 700 miles of pipeline and related facilities, originating near Mobile, Alabama, crossing the Gulf of Mexico in a southeasterly direction, and ultimately terminating near Florida's East Coast in West Palm Beach, Florida. The Gulfstream System is expected to be in service in June 2002, subject to receipt of satisfactory governmental approvals.

Power

In July 1998, the Government of Pakistan ("GOP") issued letters purporting to be "Notices of Intent to Terminate" (the "Notices") to two independent power projects affiliated with Coastal Power Company, a subsidiary of Coastal, as well as to several other independent power projects. The Company asserted that the Notices were deficient under the terms of the applicable agreement and unequivocally denied the allegations of wrongdoing contained in the Notices. In December 1998, each of the power projects and the GOP entered into Withdrawal Agreements, in which the GOP withdrew and cancelled the Notices and stated that there was no finding of wrongdoing by the projects, their shareholders, directors, officers, employees or agents.

Other

The Company is pursuing disposition of its 50% indirect ownership of ANR Advance Transportation Company, Inc. ("ANR Advance"), the Company's joint venture trucking operation. The Company expects that ANR Advance will be fully liquidated.

Item 2. Properties.

Information on properties of Coastal is included in Item 1, "Business" included herein.

The real property owned by the Company with regard to its subsidiary pipelines is owned in fee and consists principally of sites for compressor and metering stations and microwave and terminal facilities. With respect to the subsidiary-owned storage fields, the Company holds title to gas storage rights representing ownership of, or has long-term leases on, various subsurface strata and surface rights and also holds certain additional mineral rights. Under the NGA, the Company and its pipeline subsidiaries may acquire by the exercise of the right of eminent domain, through

proceedings in United States District Courts or in state courts, necessary rights-of-way to construct, operate and maintain pipelines and necessary land or other property for compressor and other stations and equipment necessary to the operation of pipelines.

Item 3. Legal Proceedings.

In connection with the December 20, 1996 sale of the Company's western coal operations, the Company assumed control of a pending dispute with the Intermountain Power Agency ("IPA") involving two coal sales agreements of Coastal States Energy Company, which contracts were included in the sale, and for which the Company continued to have certain responsibilities. On July 14, 1997, IPA made a demand for arbitration between the parties, asserting a claim of a gross inequity under the contracts requiring a reduction in the purchase price of coal sold before and after the sale of these coal operations. The Company believed that no gross inequity had occurred and that it would prevail in the arbitration on the merits. However, in an attempt to resolve this and several other unrelated issues concerning the Company's continuing responsibilities under the terms of the December 1996 sale, the Company entered into negotiation with several interested parties. Pursuant to a January 20, 1999 multi-party agreement, in which virtually all of the Company's indemnification obligations were terminated, IPA dismissed its "gross inequity" claim. This favorable resolution of all outstanding claims arising under the original sale of the western coal operations had no adverse impact on the Company.

In December 1992, certain of CIG's natural gas lessors in the West Panhandle Field filed a complaint in the U.S. District Court for the Northern District of Texas, claiming underpayment of royalties, breach of fiduciary duty, fraud and negligent misrepresentation. Management believes that CIG has numerous defenses to the lessors' claims, including (i) that the royalties were properly paid, (ii) that the majority of the claims were released by written agreement and (iii) that the majority of the claims are barred by the statute of limitations. In March of 1995, the trial court granted a partial summary judgment in favor of CIG, holding that the four-year statute of limitations had not been tolled, that the releases are valid, and dismissing all tort claims and claims for breach of any duty of disclosure. The remaining claim for underpayment of royalties was tried to a jury which, in May 1995, made findings favorable to CIG. On June 7, 1995, the trial court entered a judgment that the lessors recover no monetary damages from CIG and permanently estopping the lessors from asserting any claim based on an interpretation of the contract different than that asserted by CIG in the litigation. The lessors' motion for a new trial was denied on July 18, 1997, and both parties filed appeals. On June 7, 1996, the same plaintiffs sued CIG in state court in Amarillo, Texas for underpayment of royalties. CIG removed the second lawsuit to federal court which granted a stay of the second suit pending the outcome of the first lawsuit. Oral arguments were heard before the Fifth Circuit Court of Appeals on December 4, 1998, and the parties are awaiting the Court's decision.

In October 1996, the Company, along with several subsidiaries, was named as a defendant in a suit filed by several former and current African American employees in the United States District Court, Southern District of Texas. The suit alleges racially discriminatory employment policies and practices. Coastal vigorously denies these allegations and has filed responsive pleadings. Plaintiffs' counsel are seeking to have the suit certified as a class action of all former and current African American employees and initially claimed compensatory and punitive damages of $400 million. In February 1999, in response to Coastal's motion to deny class certification, plaintiffs' counsel obtained permission from the Court to delete all claims for compensatory and punitive damages and to seek equitable relief only. In January 1998, the plaintiffs amended their suit to exclude ANR Pipeline employees from the potential class. A new suit was then filed in state court in Wayne County, Michigan, seeking to have the Michigan suit certified as a class action of African American employees of ANR Pipeline and seeking unspecified damages as well as attorneys and expert fees. ANR Pipeline has filed responsive pleadings denying these allegations.

In 1996, Jack Grynberg filed a claim under the False Claims Act on behalf of the U.S. government in the U.S. District Court, District of Columbia, against 70 defendants, including ANR Pipeline and CIG. The suit sought damages for the alleged underpayment of royalties due to the purported improper measurement of gas. The 1996 suit was dismissed without prejudice in March 1997 and the dismissal was affirmed by the D.C. Court of Appeals in October 1998. In September 1997, Mr. Grynberg filed 77 separate, similar False Claims Act suits against natural gas transmission companies and producers, gatherers, and processors of natural gas, seeking unspecified damages. Coastal and several of its subsidiaries have been included in two of the September 1997 suits. The suits were filed in both the U.S. District Court, District of Colorado and the U.S. District Court, Eastern District of Michigan. The United States Department of

Justice has notified the Company that it is reviewing these lawsuits to determine whether or not the United States will intervene.

Numerous other lawsuits and other proceedings which have arisen in the ordinary course of business are pending or threatened against the Company or its subsidiaries.

Although no assurances can be given and no determination can be made at this time as to the outcome of any particular lawsuit or proceeding, the Company believes there are meritorious defenses to substantially all such claims and that any liability which may finally be determined should not have a material adverse effect on the Company's consolidated financial position or results of operations.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

PART II

Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters.

The principal market on which Coastal Common Stock is traded is the New York Stock Exchange; Coastal Common Stock is also listed on The Stock Exchange in London, the Stock Exchanges of Dusseldorf, Frankfurt, Hamburg and Munich in Germany and on the Amsterdam Stock Exchange. The Class A Common Stock of Coastal is non-transferable; however, such stock is convertible share-for-share into Coastal Common Stock. As of March 1, 1999, the approximate number of holders of record of Common Stock was 12,900 and of the Class A Common Stock was 2,720.

The following table presents the high and low sales prices for Coastal common shares based on the daily composite listing of transactions for New York

Stock Exchange stocks, adjusted for the 2-for-1 stock split distributed July 1, 1998.

Quarters	1998 High	1998 Low	1998 Dividends	1997 High	1997 Low	1997 Dividends
First Quarter	$34.13	$26.59	$.0500	$25.56	$22.32	$.05
Second Quarter	38.25	32.34	.0625	26.94	21.94	.05
Third Quarter	35.75	25.25	.0625	31.75	26.38	.05
Fourth Quarter	38.75	30.88	.0625	32.53	28.13	.05

Coastal expects to continue paying dividends in the future. Dividends of $.05625 per share were paid on the Class A Common Stock for the last three quarters of 1998 and $.045 per share for each quarterly period in 1997 and the first quarter of 1998. At December 31, 1998, under the most restrictive of its financing agreements, the Company was prohibited from paying dividends and distributions on its Common Stock, Class A Common Stock and preferred stocks in excess of approximately $686.1 million.

Item 6. Selected Financial Data.

The following selected financial data (in millions of dollars except per share amounts) is derived from the Consolidated Financial Statements included herein and Item 6 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1997, as adjusted for minor reclassifications. The Notes to Consolidated Financial Statements included herein contain other information relating to this data.

	Year Ended December 31,				
	1998	1997	1996****	1995	1994
Operating revenues*	$ 7,368.2	$ 9,730.1	$12,166.9**	$ 10,343.2	$ 10,072.4
Earnings from continuing operations before extraordinary items	482.9	398.7	508.0**	285.6	240.3
Net earnings	444.4	301.5	402.6**	270.4	232.6
Basic earnings per share from continuing operations before extraordinary items***	2.24	1.80	2.33**	1.28	1.07
Diluted earnings per share from continuing operations before extraordinary items***	2.21	1.77	2.30**	1.27	1.06
Cash dividends per common share***	.2375	.20	.20	.20	.20
Total assets	12,304.1	11,639.7	11,620.4	10,660.5	10,501.8
Debt, excluding current maturities	3,999.3	3,663.2	3,526.1	3,661.7	3,719.0
Preferred stock of subsidiaries, excluding current maturities*****	400.0	100.0	100.0	.6	.6

<FN>

* Amounts for 1997 include revenues for two months while 1994 through 1996 include twelve months of revenues from Coastal's gas marketing operations which became a part of Engage Energy US, L.P. and Engage Energy Canada, L.P. in February 1997 and are included in Other income - net on the equity method thereafter.

** Amounts for 1996 included a gain of $272.3 million ($177 million net of income taxes, or $.84 per share-basic, $.83 per share-diluted), related to the sale of the Utah coal mining operations. Excluding the gain, earnings from continuing operations before extraordinary items for 1996 amounted to $331.0 million ($1.49 per share-basic, $1.47 per share-diluted).

*** Adjusted for a two-for-one stock split of the Company's common stock declared on May 7, 1998. In addition, cash dividends of $.2138 per share were paid on the Company's Class A Common Stock in 1998, and $.18 was paid in 1997, 1996, 1995 and 1994.

**** Effective November 1, 1996, the Company discontinued the application of FAS 71. The accounting change resulted in a charge to earnings of $85.6 million, net of related income taxes of $50 million, and is shown as an extraordinary item. Additional information is set forth in Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 14 of the Notes to Consolidated Financial Statements.

***** Amounts for 1998 include $300.0 million of Company-obligated mandatory redemption preferred securities of a consolidated trust.

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</TABLE>

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The Management's Discussion and Analysis of Financial Condition and Results of Operations is presented on pages F-1 through F-12 hereof.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

For the information required by this item, see discussion under Management's Discussion and Analysis of Financial Condition and Results of Operations, which is presented on pages F-4 and F-5.

Item 8. Financial Statements and Supplementary Data.

The Financial Statements and Supplementary Data required hereunder are included in this Annual Report as set forth in Item 14(a) hereof.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

PART III

Item 10. Directors and Executive Officers of the Registrant.

The information called for by this Item with respect to the directors is set forth under "Election of Directors" and "Information Regarding Directors" in the Coastal Proxy Statement for the May 6, 1999 Annual Meeting of Stockholders filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, and is incorporated herein by reference.

The executive officers of the Registrant as of March 10, 1999, were as follows:

Name (Age), Year First Elected An Officer	Positions and Offices with the Registrant
David A. Arledge (54), 1982	Chairman of the Board, President and Chief Executive Officer

Coby C. Hesse (51), 1986	Executive Vice President
James A. King (59), 1992	Executive Vice President
Jeffrey A. Connelly (52), 1988	Senior Vice President
Carl A. Corrallo (55), 1993	Senior Vice President and General Counsel
Rodney D. Erskine (54), 1997	Senior Vice President
Donald H. Gullquist (55), 1994	Senior Vice President
Dan J. Hill (58), 1978	Senior Vice President
Kenneth O. Johnson (78), 1978	Senior Vice President and Director
Austin M. O'Toole (63), 1974	Senior Vice President and Secretary
Jack C. Pester (64), 1987	Senior Vice President
James L. Van Lanen (54), 1985	Senior Vice President
Thomas M. Wade (46), 1995	Senior Vice President
M. Truman Arnold (70), 1993	Vice President
Daniel F. Collins (57), 1989	Vice President
Thomas E. Jackson (59), 1997	Vice President
Jeffrey B. Levos (38), 1997	Vice President and Controller
John J. Lipinski (48), 1995	Vice President
Stirling D. Pack, Jr. (51), 1999	Vice President
M. Frank Powell (48), 1993	Vice President
Keith O. Rattie (44), 1996	Vice President
Ronald D. Matthews (51), 1994	Treasurer

The above named persons bear no family relationship to each other. Their respective terms of office expire coincident with the officer elections at the Annual Board of Directors' meeting which follows Coastal's Annual Meeting of Stockholders. Each of the officers named above have been officers of Coastal, ANR Pipeline and/or Colorado or subsidiaries thereof for five years or more with the following exceptions:

Mr. Erskine was elected Senior Vice President of Coastal in August 1997. He has held various positions with Coastal Oil & Gas Corporation, a subsidiary of Coastal, since 1994. Before joining Coastal, Mr. Erskine was president and chief executive officer of Nerco Oil & Gas Inc.

Mr. Gullquist was elected Senior Vice President of Coastal in March 1994. From 1988 to 1989 he served as Vice President, Finance at Enron Corporation; from 1989 to 1990 he served as president of Enron Finance Corporation.

Mr. Levos was elected Vice President and Controller of Coastal in March 1997. He has served as Vice President of Coastal States Management Corporation, a subsidiary of Coastal, since December 1995 and also served as General Auditor since July 1994. Prior thereto, he was a Certified Public Accountant with the Houston office of Deloitte & Touche LLP since January 1986.

Mr. Rattie was elected Vice President of Coastal in December 1996. He was formerly President of Coastal Gas International, Ltd., a Coastal subsidiary responsible for international gas project development. Mr. Rattie joined Coastal in 1995. Previously he spent 18 years with the Chevron Corporation. From 1991 to 1995, Mr. Rattie was General Manager, International Gas Development with Chevron International Oil Company.

Certain information called for by this item is set forth under "Compliance with Section 16(a) of the Exchange Act" in the Coastal Proxy Statement for the May 6, 1999 Annual Meeting of Stockholders filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, and is incorporated herein by reference.

Item 11. Executive Compensation.

The information called for by this item is set forth under "Executive Compensation," "Compensation and Executive Development Committee Report on Executive Compensation," "Pension Plan Table" and "Performance Graph - Shareholder Return on Common Stock" in the Coastal Proxy Statement for the May 6, 1999 Annual Meeting of Stockholders filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

The information called for by this item is set forth under "Stock Ownership," "Election of Directors" and "Information Regarding Directors" in the Coastal Proxy Statement for the May 6, 1999 Annual Meeting of Stockholders filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions.

The information called for by this item is set forth under "Election of Directors" and "Transactions with Officers and Directors" in the Coastal Proxy Statement for the May 6, 1999 Annual Meeting of Stockholders filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, and is incorporated herein by reference.

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

(a) The following documents are filed as part of this Annual Report or incorporated herein by reference:

1. Financial Statements and Supplemental Information.

The following Consolidated Financial Statements of Coastal and Subsidiaries and Supplemental Information are included in response to Item 8 hereof on the attached pages as indicated:

2. Financial Statement Schedules.

The following schedules of Coastal and Subsidiaries are included on the attached pages as indicated:

Schedules other than those referred to above are omitted as not applicable or not required, or the required information is shown in the Consolidated Financial Statements or Notes thereto.

3. Exhibits.

3.1+ Restated Certificate of Incorporation of Coastal, as restated on March 22, 1994. (Filed as Module TCC-Artl-Incorp on March 28, 1994).

3.2+ By-Laws of Coastal, as amended on January 16, 1990 (Exhibit 3.4 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1989).

4 (With respect to instruments defining the rights of holders of long-term debt, the Registrant will furnish to the Commission, on request, any such documents).

10.1+ 1984 Stock Option Plan (Appendix B to Coastal's Proxy Statement for the 1984 Annual Meeting of Stockholders, dated May 14, 1984).

10.2+ 1985 Stock Option Plan (Appendix A to Coastal's Proxy Statement for the 1986 Annual Meeting of Stockholders, dated March 27, 1986).

Note:

\+ Indicates documents incorporated by reference from the prior filing indicated.

10.3+ The Coastal Corporation Performance Unit Plan effective as of January 1, 1987 (Exhibit 10.5 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1987).

10.4+ The Coastal Corporation Replacement Pension Plan effective as of November 1, 1987 (Exhibit 10.6 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1987).

10.5+ Description of Coastal's Key Employees Bonus Plan (Exhibit 10.7 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1987).

10.6+ The Coastal Corporation Stock Purchase Plan, as restated on January 1, 1994 (Appendix B to Coastal's Proxy Statement for the 1994 Annual Meeting of Stockholders dated March 29, 1994).

10.7+ The Coastal Corporation Amended and Restated Stock Grant Plan, effective October 9, 1997. (Exhibit 10.7 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)

10.8+ The Coastal Corporation Amended and Restated Deferred Compensation Plan for Directors, effective October 9, 1997. (Exhibit 10.8 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)

10.9+ The Coastal Corporation 1990 Stock Option Plan (Exhibit 10.13 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1989).

10.10+ The Coastal Corporation 1997 Directors Stock Plan, effective June 5, 1997. (Exhibit 10.10 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)

10.11+ The Coastal Corporation Deferred Compensation Plan (Exhibit 10.14 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1993).

10.12+ The Coastal Corporation 1994 Incentive Stock Plan (Appendix A to Coastal's Proxy Statement for the 1994 Annual Meeting of Stockholders dated March 29, 1994).

10.13+ Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, includes Plan as Restated as of January 1, 1989 and First Amendment dated July 27, 1992, Second Amendment dated December 9, 1992, Third Amendment dated October 29, 1993 (Exhibit 10.16 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1993).

10.14+ Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, as further amended by the Fourth Amendment dated May 20, 1994, Fifth Amendment dated August 17, 1994, Sixth Amendment dated August 30, 1994, Seventh Amendment dated

October 30, 1995, Eighth Amendment dated December 29, 1995 and Ninth Amendment dated December 29, 1995 (Exhibit 10.14 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1995).

10.15+ Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, as further amended by the Tenth Amendment dated March 25, 1996 (Exhibit 10.15 to Coastal's Quarterly Report on Form 10-Q for the period ended March 31, 1996).

10.16+ Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, as further amended by the Twelfth Amendment dated August 29, 1996 and the Thirteenth Amendment dated September 16, 1996 (Exhibit 10.16 to Coastal's Quarterly Report on Form 10-Q for the period ended September 30, 1996).

Note:

+ Indicates documents incorporated by reference from the prior filing indicated.

* Indicates documents filed herewith.

10.17+ Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, as further amended by the Eleventh Amendment dated December 6, 1996. (Exhibit 10.17 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1996.)

10.18+ Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, as further amended by the Fourteenth Amendment dated December 31, 1997. (Exhibit 10.18 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)

10.19+ Agreement for Consulting Services between The Coastal Corporation and Oscar S. Wyatt, Jr. dated August 1, 1997. (Exhibit 10.19 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)

10.20+ The Coastal Corporation 1998 Incentive Stock Plan, effective March 19, 1998 (Appendix A to Coastal's Proxy Statement for the 1998 Annual Meeting of Stockholders dated March 26, 1998).

11* Statement re Computation of Per Share Earnings.

21* Subsidiaries of Coastal.

23* Consent of Deloitte & Touche LLP.

24* Powers of Attorney (included on signature pages herein).

27* Financial Data Schedule.

99+ Indemnity Agreement revised and updated as of April, 1988 (Exhibit 28 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1990).

Note:

+ Indicates documents incorporated by reference from the prior filing indicated.

* Indicates documents filed herewith.

(b) Reports on Form 8-K.

No reports on Form 8-K were filed during the quarter ended December 31, 1998.

POWERS OF ATTORNEY

Each person whose signature appears below hereby appoints David A. Arledge, Coby C. Hesse and Austin M. O'Toole and each of them, any one of whom may act without the joinder of the others, as his attorney-in-fact to sign on his behalf and in the capacity stated below and to file all amendments to this Annual Report on Form 10-K, which amendment or amendments may make such changes and additions thereto as such attorney-in-fact may deem necessary or appropriate.

SIGNATURES

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

THE COASTAL CORPORATION
(Registrant)

By: DAVID A. ARLEDGE

David A. Arledge
Chairman of the Board, President and
Chief Executive Officer
March 26, 1999

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

By: DAVID A. ARLEDGE

David A. Arledge
Chairman of the Board, President,
Chief Executive Officer and Chief Financial
Officer (Principal Executive Officer and
Principal Financial Officer)
March 26, 1999

By: COBY C. HESSE

Coby C. Hesse
Principal Accounting Officer
March 26, 1999

By: JOHN M. BISSELL

John M. Bissell
Director
March 26, 1999

* * *

By: GEORGE L. BRUNDRETT, JR.

George L. Brundrett, Jr.
Director
March 26, 1999

By: KENNETH O. JOHNSON

Kenneth O. Johnson
Director
March 26, 1999

By: HAROLD BURROW
Harold Burrow
Director
March 26, 1999

By: JEROME S. KATZIN
Jerome S. Katzin
Director
March 26, 1999

By: ROY D. CHAPIN, JR.
Roy D. Chapin, Jr.
Director
March 26, 1999

By: J. CARLETON MACNEIL, JR.
J. Carleton MacNeil, Jr.
Director
March 26, 1999

By: JAMES F. CORDES
James F. Cordes
Director
March 26, 1999

By: THOMAS R. McDADE
Thomas R. McDade
Director
March 26, 1999

By: ROY L. GATES
Roy L. Gates
Director
March 26, 1999

By: O. S. WYATT, JR.
O. S. Wyatt, Jr.
Director
March 26, 1999

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This report, including Management's Discussion and Analysis of Financial Condition and Results of Operations, includes certain forward-looking statements. The forward-looking statements reflect the Company's expectations, objectives and goals with respect to future events and financial performance, and are based on assumptions and estimates which the Company believes are reasonable. However, actual results could differ materially from anticipated results. Important factors which may affect the actual results include, but are not limited to, commodity prices, political developments, market and economic conditions, industry competition, the weather, changes in financial markets, changing legislation and regulations, and the impact of the Year 2000 issue. The forward-looking statements contained in this Report are intended to qualify for the safe harbor provisions of Section 21E of the Securities Exchange Act of 1934, as amended.

The Notes to Consolidated Financial Statements contain information that is pertinent to the following analysis.

Liquidity and Capital Resources

The Company uses the following consolidated ratios to measure liquidity and ability to meet future funding needs and debt service requirements.

	1998	1997	1996
Return on average common stockholders' equity	14.6%	13.1%	18.8%
Cash flow from operating activities to long-term debt	28.7%	26.7%	16.3%
Total debt to total capitalization	52.1%	53.0%	53.7%
Times interest earned (before tax)	3.2	2.7	2.8

The above ratios reflect increased stockholders' equity and debt in 1998 and 1997. The increases in the cash flow from operating activities to long-term debt ratio resulted from changes in working capital, earnings from operations and long-term debt.

Cash flows provided from operating activities were $1,146.3 million in 1998, $976.9 million in 1997 and $574.6 million in 1996. The change in 1998 was due to increases for earnings from continuing operations before extraordinary items and deferred income taxes. The 1997 increase can be primarily attributed to decreases for working capital requirements.

Capital expenditures amounted to $1,404.0 million, $996.7 million and $880.8 million in 1998, 1997 and 1996, respectively. Exploration and Production capital expenditures increased by $360.4 million over 1997, 88% of the Company's total increase, as the continued successful programs again resulted in reserve additions which were more than three times 1998 production. Capital expenditures for Refining, Marketing and Chemicals increased 37%, primarily due to expansion projects at the Aruba refinery. Natural Gas capital expenditures decreased 14% as system expansions for the interstate pipelines were down from 1997. Capital expansion for the Coal segment was up 85% as the Company continued its transformation from a processing and marketing company using contract miners into an integrated company that mines, processes and sells its own coal. The increased 1997 capital expenditures were primarily due to continued expansion in the Exploration and Production segment which resulted in reserve additions which were also more than three times 1997 production. Natural Gas expenditures increased 6% due to system expansions for the interstate pipelines. Capital expenditures decreased for the Refining, Marketing and Chemicals segment as major projects were completed in 1996 at the refineries and for the Coal segment as a result of the sale of the Utah mines in 1996.

The increase in proceeds from the sale of property, plant and equipment for 1998 of $14.4 million results primarily from the sale of certain non-core Natural Gas processing and gathering assets. Proceeds from the sale of property, plant and equipment in 1997, of which 37% was from the Refining, Marketing and Chemicals segment, were comparable to the 1996 amount. The proceeds from the Refining, Marketing and Chemicals segment partially resulted from its strategy of eliminating marginal activities. Additions to investments increased in 1998 as a result of the Power segment increasing

its interest in existing plants, completing new projects and pursuing opportunities in the United States and abroad, while the 1997 increase included a $50 million investment in marketable securities, as well as increases for gas pipeline ventures. Proceeds from investments decreased in 1998 due to a reduction in amounts from Refining, Marketing and Chemical ventures and increased in 1997 as a result of amounts received from gas pipeline ventures.

The Company increased total debt by $393.6 million in 1998 and $180.1 million in 1997. The 1998 and 1997 increases were used for capital expenditures and additions to investments.

On April 15, 1998, the Company redeemed all 8,000,000 outstanding shares of its $2.125 Cumulative Preferred Stock, Series H. Redemption price for the Series H stock was $25 per share plus accrued dividends of $.182986 to April 15, 1998.

A two-for-one stock split of Coastal's common stock was declared in May 1998. Stockholders of record received one additional share of common stock for each share of common and/or Class A common stock held.

On May 13, 1998, Coastal completed a public offering of 12,000,000 Coastal-obligated mandatory redemption preferred securities through an affiliate, Coastal Finance I, a business trust (the "Trust"), for $300 million in cash. The Trust holds debt securities of Coastal purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375% of the liquidation amount of $25 per preferred security. The proceeds were used to refinance borrowings incurred to finance the redemption of the Series H Preferred Stock discussed above and to repay certain outstanding subsidiary indebtedness. The preferred securities are mandatorily redeemable on the maturity date, May 13, 2038, and may be redeemed at the Company's option on or after May 13, 2003, or earlier if certain events occur. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption.

In June 1998, the Company completed public offerings of $200 million of

6.5% senior debentures due 2008 and $200 million of 6.95% senior debentures due 2028. The net proceeds from the sale were used to repay variable rate indebtedness, including indebtedness of a subsidiary under a revolving credit facility.

In February 1999, the Company completed a public offering of $200 million of 6.375% senior debentures due 2009. The net proceeds from the sale were used to repay floating rate indebtedness of a subsidiary under a revolving credit facility.

Capital expenditures for 1999, including the Company's equity investments in partnerships and joint ventures, are currently projected at approximately $1.5 billion; however, future expenditures are dependent on conditions in the energy industry. These expenditures are primarily for completion of projects in process, operational necessities, environmental requirements, expansion projects and increased efficiency. Other expansion opportunities will continue to be evaluated.

Financing for budgeted expenditures and mandatory debt retirements in 1999 will be accomplished by the use of internally generated funds, existing credit lines, proceeds from the selective sale of non-core assets and new financings.

Funding for certain proposed projects is anticipated to be provided through non-recourse project financings in which the projects' assets and contracts will be pledged as collateral. Equity participation by other entities will also be considered. To the extent required, cash for equity contributions to projects will be from general corporate funds.

The Company is undertaking an aggressive and comprehensive program in 1999 to reduce costs and improve efficiencies, as well as continuing an emphasis on divestment of less profitable non-core operations.

Unused lines of credit at December 31, 1998 were as follows (Millions of Dollars):

Short-term..................................	$ 649.0
Long-term*..................................	456.0
	$ 1,105.0

*$45.1 million of unused long-term credit lines is dedicated to a specific use.

Credit agreements of certain subsidiaries contain covenants which limit the making of advances to affiliates and payment of dividends. Where applicable, restrictions are generally in the form of computed capacities with respect to advances and the payment of dividends. At December 31, 1998, net assets of consolidated subsidiaries amounted to approximately $6.8 billion, of which approximately $653.0 million was restricted. These provisions have not, and are not expected to, have any meaningful impact on the ability of the Company to meet its cash obligations.

The Financial Accounting Standards Board ("FASB") has issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133") to be effective for all fiscal quarters of fiscal years beginning after June 15, 1999. FAS 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. The accounting for changes in the fair value of a derivative will depend on the intended use of the derivative and the resulting designation. The Company is currently evaluating the impact of FAS 133.

The FASB Emerging Issues Task Force Issue No. 98-10, to be effective for years beginning after December 15, 1998, states that energy trading contracts (as defined) should be marked to market with the gains and losses included in earnings and separately disclosed in the financial statements or footnotes thereto. The Company does not believe the application of Issue No. 98-10 will have a material effect on its consolidated financial statements.

The Accounting Standards Executive Committee of the American Institute of Certified Public Accountants has issued Statement of Position 98-5 ("SOP 98-5"), to be effective for periods beginning after December 15, 1998. SOP 98-5 provides guidance on accounting for costs incurred to open new facilities, conduct business in new territories or otherwise commence some new operation. The application of SOP 98-5 is not expected to have a material effect on the Company's consolidated financial statements.

In January 1999, certain countries of the European Union adopted the Euro as their legal common currency. This conversion to the Euro is not expected to have a material effect on the Company's consolidated results of operations, financial position or cash flows as the Company does not have significant European operations.

The Company's operations are subject to extensive and evolving federal, state and local environmental laws and regulations. Compliance with such laws and regulations can be costly. Additionally, governmental authorities may enforce the laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties and remediation requirements.

The Company spent approximately $13 million in 1998 on environmental capital projects and anticipates capital expenditures of approximately $44 million in 1999 in order to comply with such laws and regulations. The majority of the 1999 expenditures are attributable to projects at the Company's refining, chemical and terminal facilities. The Company currently anticipates capital expenditures for environmental compliance for the years 2000 through 2002 of $20 million to $40 million per year.

The Comprehensive Environmental Response, Compensation and Liability Act, also known as "Superfund," imposes liability for the release of a "hazardous substance" into the environment. Superfund liability is imposed without regard to fault and even if the waste disposal was in compliance with the then current laws and regulations. With the joint and several liability imposed under Superfund, a potentially responsible party ("PRP") may be required to pay more than its proportional share of such costs. Certain subsidiaries of the Company and a company in which Coastal owns a 50% interest have been named as a PRP in several "Superfund" waste disposal sites. At the 11 sites for which there is sufficient information, total cleanup costs are estimated to be approximately $620 million, and the Company estimates its pro-rata exposure, to be paid over a period of several years, is approximately $7.5 million and has made appropriate provisions. At nine other sites, the Environmental Protection Agency ("EPA") is currently unable to provide the Company with an estimate of total cleanup costs and, accordingly, the Company is unable to calculate its share of those costs. Additionally, certain subsidiaries of the Company have been named as PRPs in two state sites. At one site, the North Carolina Department of Health, Environment and Natural Resources has estimated the total cleanup costs to be approximately $50 million, but the Company believes that the subsidiaries' activities at this site were de minimis. At the second state site, the Florida Department of Environmental Protection has demanded reimbursement of its costs, which total $100,000, and suitable remediation. There is not sufficient information to estimate the remedial costs or the Company's pro-rata exposure at this site.

Future information and developments, including legislative and enforcement developments, will require the Company to continually reassess the expected impact of these environmental matters. However, the Company has evaluated its total environmental exposure based on currently available data, including its potential joint and several liability, and believes that compliance with all applicable laws and regulations will not have a material adverse impact on the Company's consolidated financial position or results of operations.

Market Risk Management

The Company uses fixed and variable rate debt to partially finance budgeted expenditures and mandatory debt retirements. These agreements expose the Company to market risk related to changes in interest rates. Derivative financial instruments, specifically interest rate swaps, are used to reduce and manage this risk. The Company has entered into a number of interest rate swap agreements designated as a partial hedge of the Company's portfolio of variable rate debt. The Company does not hold or issue financial instruments for trading purposes.

The following table presents hypothetical changes in fair values in the Company's debt obligations and other market sensitive financial instruments at December 31, 1998 and 1997. The modeling technique used measures the change in fair values arising from selected changes in interest rates. Market changes reflect immediate hypothetical changes in interest rates at December 31. Fair values are calculated as the net present value of the expected cash flows of the financial instrument.

<TABLE>
<CAPTION>

Millions of Dollars	No Change	10% Increase		10% Decrease	
Impact of changes in market rates of interest on:	Fair Value	Fair Value	Increase (Decrease)	Fair Value	Increase (Decrease)
<S>	<C>	<C>	<C>	<C>	<C>
Assets					
Notes receivable and marketable debt securities					
1998.........................	$ 312.2	$ 305.2	$ (7.0)	$ 319.8	$ 7.6
1997.........................	279.4	271.1	(8.3)	288.6	9.2
Liabilities					
Long-term debt subject to fixed interest rates					
1998.........................	$ 2,982.7	$ 2,875.9	$ (106.8)	$ 3,097.3	$ 114.6
1997.........................	2,619.5	2,513.2	(106.3)	2,733.6	114.1
Preferred Stock of Subsidiaries					
Mandatory redemption preferred securities of a consolidated trust					
1998.........................	$ 295.6	$ 279.2	$ (16.4)	$ 313.4	$ 17.8
1997.........................	-	-	-	-	-

</TABLE>

The Company is not subject to fair value risk resulting from changes in market rates of interest on its portfolio of variable rate obligations, including notes payable, long-term debt, other commitments and variable to fixed swaps with an aggregate fair value of approximately $2,071.8 million at December 31, 1998. However, variable rate obligations do expose the Company to possible increases in interest expense and decreases in earnings if interest rates were to rise. If interest rates were to immediately increase by 10% from the December 31, 1998 levels and continue through 1999 assuming no changes in debt levels, interest expense, including the effects of interest rate swaps, would increase by approximately $11.4 million with a corresponding decrease in earnings before taxes, as compared to a $10.7 million increase at December 31, 1997.

A subsidiary of the Company has issued preferred stock with a fair value of $100 million. The preferred stock pays cumulative preferred dividends at a variable rate tied to market rates of interest. This stock exposes the Company to potential decreases in earnings should interest rates increase. An immediate 10% increase in market rates of interest,

continuing through 1999, assuming no change in outstanding shares, would decrease earnings before taxes by approximately $0.5 million, compared to a $0.6 million decrease at December 31, 1997.

The Company also holds certain equity securities that expose the Company to price risk associated with equity security markets. These securities are carried at their fair value of $23.0 million at December 31, 1998. An immediate decrease in the market prices of these securities of 10% would result in a fair value of approximately $20.7 million, or a decrease in earnings before taxes of approximately $2.3 million. The potential loss at December 31, 1997 was $1.8 million.

The Company also enters into swaps, futures and other contracts to hedge exposure to price risks associated with crude oil, refined product and natural gas inventories, commitments and certain anticipated transactions. The table below presents the hypothetical changes in fair values arising from immediate selected potential changes in the quoted market prices of derivative commodity instruments outstanding at December 31, 1998 and 1997. Gain or loss on these derivative commodity instruments would be offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table. Derivative commodity instruments held or issued for trading purposes are not material at December 31, 1998, and the results of such trading were not material to the financial results of the Company for 1998.

Millions of Dollars	No Change	10% Increase		10% Decrease	
Impact of changes in market rates of interest on:	Fair Value	Fair Value	Increase (Decrease)	Fair Value	Increase (Decrease)
Commodity futures					
1998.........................	$ (27.3)	$ (30.7)	$ (3.4)	$ (23.9)	$ 3.4
1997.........................	(15.3)	(20.3)	(5.0)	(10.3)	5.0

In addition, the repayment terms of certain long-term variable rate debt with a fair value of $141.2 million at December 31, 1998, is linked to the quoted market price of crude oil in order to hedge inventory and certain anticipated activity against the risk of market changes in the price of crude oil. An immediate, hypothetical increase of 10% in the price of crude oil at December 31, 1998 would result in an increase of $12.9 million in the fair value of this debt, which would be offset by a corresponding increase in the fair value of the hedged activities. The hypothetical gain in fair value at December 31, 1997 was $18.9 million. The decrease in the hypothetical change is due to the decrease in oil prices in 1998.

The Company's utilization of derivative financial and commodity instruments in managing market risk exposures described above is consistent with the prior year.

Year 2000. Coastal, like most other companies, is addressing the Year 2000 issue. This issue is the result of computer programs written with two digits rather than four to define the applicable year. Computer programs that have date-sensitive software using two digits to define the applicable year may recognize a date using "00" as the year 1900 instead of the year 2000. This could result in a system failure or miscalculations causing disruptions of operations, including, among other things, a temporary inability to process transactions, send invoices, or engage in similar normal business activities.

The Company's Year 2000 compliance project relates to both information technology and embedded systems throughout the Company and focuses on all technology hardware and software, external interfaces with customers and suppliers, operations process control, automation and instrumentation systems. Systems are being reviewed in an order of priority that includes an assessment of the potential adverse effects of noncompliance as well as an assessment of the complexity of the system. Assessment has been substantially completed for all systems. It will be necessary to modify or replace certain noncompliant software and hardware so that they will properly utilize dates beyond December 31, 1999. The Company believes that with such remediation, the Year 2000 issue can be mitigated. Necessary remediation and testing activities have begun and are planned to be completed for all material systems by mid-1999. Remaining systems modifications, replacement and testing are planned to be completed before the end of 1999.

The Company is continuing with a formal communications process with outside entities with which the Company conducts business to determine the extent to which those companies are addressing their Year 2000 compliance. In connection with this process, the Company has been sending letters and questionnaires to these parties and is evaluating the responses as received and is following up with those parties that have not responded. The Company does not expect any single noncompliant third party to have a material effect on the Company as it does not rely to a material extent on any single customer or supplier, including telecommunications providers, utilities and banks. However, the Company does not control these parties and there can be no assurance that third-party systems will be timely converted, or that any failure to convert would not have an adverse effect on the Company's systems. The Company will continue to cooperate and communicate with these parties to mitigate potential adverse effects.

The Company is currently preparing and will periodically update a Year 2000 contingency plan. The primary goals of the plan are to maintain continuity of operations, timely resume any operations that have been interrupted, preserve Company assets and protect the environment. Coastal's diversity and distribution on a business unit, geographical and customer basis are expected to naturally reduce the risk of major disruptions to worldwide operations due to any Year 2000-related occurrence. Similarly, the Company's distributed information systems and wide scope of relationships with financial institutions, suppliers and vendors will most likely aid in limiting and localizing any individual Year 2000 failure to specific operations or facilities. Also, in recent years the Company has replaced or updated a significant portion of its computer hardware and software. The plan will include possible manual intervention to operate noncompliant facilities or systems until they can be modified or replaced. Notwithstanding the foregoing, due to the nature of contingency planning, there can be no assurance that such plans will acceptably mitigate the risk of material impact to the Company's operations due to any Year 2000-related incident.

The Company has been using both external and internal resources to reprogram or replace its software and embedded systems for the Year 2000 issue. While the Company has included the Year 2000 project in its overall information systems planning process since 1996, certain systems were identified for replacement prior to the organization of the Year 2000 project. These amounts are not included in the Year 2000 project cost estimates, except where the replacement date has been accelerated in order to address Year 2000 issues. To date, the amounts incurred and expensed for developing and carrying out the plan total approximately $12 million. The total remaining cost for addressing the Year 2000 issue, which will be funded through operating cash flows, is currently estimated by management to be approximately $5 million.

It should be noted that the ultimate amount of Year 2000 costs is difficult to estimate due to possible disruptions in business arising from Year 2000 noncompliance of vendors, suppliers, customers and other third parties over whom the Company has no control. Notwithstanding the Company's efforts, disruptions could occur in its business due to Year 2000 problems and such disruptions could have an adverse effect.

Results of Operations

The Company operates principally in the following lines of business: natural gas; refining, marketing and chemicals; exploration and production; coal; and power.

Natural Gas. Natural Gas operations involve the production, purchase, gathering, storage, transportation and sale of natural gas, principally to utilities, industrial customers and other pipelines, and include the operations of natural gas liquids extraction plants. The operations involve both regulated and unregulated companies.

The interstate natural gas pipeline and certain storage subsidiaries are subject to the regulations and accounting procedures of the Federal Energy Regulatory Commission ("FERC"). The Company's subsidiaries historically followed the reporting and accounting requirements of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" ("FAS 71"). Effective November 1, 1996, these subsidiaries discontinued application of FAS 71. This accounting change has no direct effect on either the subsidiaries' ability to include the previously deferred items in future rate proceedings or on their ability to collect the rates set thereby. The Company believes this accounting change results in financial reporting which better reflects the results of operations in the economic environment in which these subsidiaries operate.

The Company's interstate pipelines operate under FERC Order 636. The intent of Order 636 is to insure that interstate pipeline transportation services are equal in quality for all gas supplies, whether the buyer purchases gas from the pipeline or from any other gas supplier. The FERC requires the use of the straight fixed variable ("SFV") rate setting methodology. In general, SFV provides that all fixed costs of providing service to firm customers (including an authorized return on rate base and associated taxes) are to be received through fixed monthly reservation charges, which are not a function of volumes transported, and provides that the pipeline's variable operating costs are received through the commodity billing component. In addition, Order 636 has resulted in the incurrence of transition costs. However, Order 636 provides mechanisms for the recovery of such costs within a reasonable time period.

In September 1996, Coastal and Westcoast Energy Inc. ("Westcoast") jointly announced plans to form one of North America's largest marketers of natural gas and electricity through the combination of the operations of the two companies' related marketing and service subsidiaries. Agreements were concluded in February 1997, which created Engage Energy US, L.P. and Engage Energy Canada, L.P. ("Engage") in which Coastal and Westcoast indirectly own 50% each. Subsequent to the combination, Coastal's share of Engage's net earnings is included in Other income-net.

<TABLE>
<CAPTION>

	Millions of Dollars		
	1998	1997	1996
<S>	<C>	<C>	<C>
Operating revenues..	$ 1,358.4	$ 2,166.2	$ 3,989.5
Depreciation, depletion and amortization........................	118.3	136.5	161.7
Earnings before interest and income taxes.......................	594.3	583.0	490.8
Total throughput volume (Bcf)..................................	2,132	2,190	2,246

</TABLE>

1998 Versus 1997. The decrease in operating revenues of $808 million is primarily a result of the Company's unregulated gas marketing operations which became a part of Engage in 1997. The revenues from these operations, which are included in the Company's revenues through February 1997, resulted in a decrease of $833.5 million for the 1998 period. Revenues for 1997 also include a $42 million gain from an equalization payment recognized in connection with the Engage combination. The 1998 revenues include a $59 million gain from the sale of certain non-core natural gas processing and gathering assets. Transportation and storage revenues decreased in 1998.

Purchases decreased by $793 million, primarily due to the combination of the Company's unregulated natural gas marketing operations noted above. Gross profit decreased by $15 million in 1998.

Earnings before interest and income taxes ("EBIT") increased by $11 million as a result of the $59 million gain from the sale of assets noted above; proceeds of $27 million received from the termination of gas transportation agreements; $39 million from a rate case settlement; reduced depreciation, depletion and amortization of $18 million; and decreased operating and general expenses of $20 million partially offset by the $42 million 1997 gain discussed above; decreased earnings from equity investments of $12 million; reduced transportation, storage and gathering revenues of $43 million; a decrease of $8 million from the combination of gas marketing operations; reduced revenues of $34 million from the operations of gas plants and sale of extracted products; and other decreases of $13 million. The reduced transportation, storage and gathering revenues result from warmer than normal weather, decreased rates and continued intensified competition across the United States natural gas industry. Depreciation, depletion and amortization decreased due to the revision of depreciation rates for certain assets as discussed in Note 1 of the Notes to Consolidated Financial Statements. The decreased earnings from equity investments includes a one-time charge of $15 million in 1998 related to the default on delivery obligations by a supplier of electricity to Engage. Operating expenses decreased primarily due to reductions for gas plant operations. The other decreases are primarily due to reduced gross profit from gas sales.

Demand for natural gas is expected to increase substantially in North America. In anticipation of this demand growth, Coastal's pipelines' strategy is to find and develop new gas reserves and position our assets to move gas from the primary supply areas to our core growth markets in the Midwest and the East.

1997 Versus 1996. The decrease in operating revenues of $1,823 million can be primarily attributed to the Company's unregulated gas marketing operations which became a part of Engage. The revenues from those operations, which are not included in the Company's revenues after February 1997, resulted in a decrease of $2,320 million in 1997.

Partially offsetting the decrease noted above were increased prices and volumes for gas sales, primarily during the first two months of 1997, and a $42 million gain from an equalization payment recognized in connection with the Engage combination. Transportation, storage and gathering revenues increased slightly in 1997.

Purchases decreased by $1,880 million from 1996, primarily due to the combination of the unregulated gas marketing operations noted above, partially offset by increased prices and volumes for gas purchases, primarily in the first two months of 1997. Gross profit increased by $57 million in 1997.

The increase in EBIT of $92 million resulted from increased gas sales volumes of $22 million; the $42 million gain from the equalization payment discussed above; increased transportation, storage and gathering revenues of $3 million; decreased depreciation, depletion and amortization of $25 million; and decreased operating expenses of $33 million offset by lower gas sales margins of $8 million; a decrease of $12 million from the combination of gas marketing operations; and other decreases of $13 million. The reduction in depreciation, depletion and amortization was primarily due to the revision of depreciation rates for certain assets of the regulated interstate pipelines and certain storage subsidiaries during 1997. Operating expenses decreased due to reductions for recovery amortizations and transportation services. The other decreases were primarily due to reduced revenue related to the sale of property, plant and equipment.

Refining, Marketing and Chemicals. Refining, marketing and chemicals operations involve the purchase, transportation and sale of refined products, crude oil, condensate and natural gas liquids; the operation of refineries and chemical plants; the sale at retail of gasoline, petroleum products and convenience items; petroleum product terminaling and marketing of crude oil and refined petroleum products worldwide.

<TABLE>
<CAPTION>

	Millions of Dollars		
	1998	1997	1996
<S>	<C>	<C>	<C>
Operating revenues...	$ 5,202.7	$ 6,877.1	$ 7,364.8
Depreciation, depletion and amortization.......................	78.3	74.6	73.3
Earnings before interest and income taxes......................	243.9	95.6	94.4
Refined product sales (millions of barrels)....................	300	279	307

</TABLE>

1998 Versus 1997. The decrease in operating revenues of $1,674 million is due to reduced prices partially offset by increased volumes. Although throughput at the Company's refineries was down in 1998 due to scheduled turnarounds, sales of refined products, including products purchased from others, was up 8%.

Purchases decreased by $1,809 million, also due to reduced prices partially offset by increased volumes, resulting in a gross profit increase of $135 million. The reduced purchases can also be attributed to the Company's increasing ability to use less expensive heavy and sour crudes.

The gross profit increase results from increased margins of $105 million; higher sales volumes of $24 million; and an increase of $8 million from the sale, trading and exchanging of third party products partially offset by other decreases of $2 million.

The EBIT increase of $148 million results from the increased gross profit of $135 million and reduced operating expenses of $25 million partially offset by increased depreciation, depletion and amortization of $4 million and reduced earnings from equity investments of $8 million. The reduced operating expenses result from reductions for the retail operations, primarily as a result of the sale of certain stores in 1998, and the closure of certain terminal operations in the northeastern United States in 1997.

Coastal's improved performance results from operational enhancements and investments to produce lighter, higher value products from lower cost heavy and sour crudes. The Company will continue its strategy of refocusing its marketing assets to eliminate marginal activities and focus on businesses that support its core refining assets and reduce working capital requirements.

1997 Versus 1996. Operating revenues decreased by $488 million due to reduced sales volumes and prices. The volume decrease was partially due to mild weather in the northeastern United States as well as the ongoing refocusing

of the Company's marketing assets to eliminate marginal activities and expand operations directly supporting the Company's core refining assets. Throughput at the Company's refineries was down 13,000 barrels per day from 1996.

Purchases for the segment decreased by $497 million, resulting in a gross profit increase of $9 million. Increased margins of $32 million were partially offset by lower sales volumes of $16 million and other decreases of $7 million. The other decreases were due to reduced gross profit from the sale of convenience store merchandise of $3 million and other reductions of $4 million. The improved margins, which include the impact of inventory losses that resulted from falling product and crude oil prices, increased significantly in the last three quarters due to the Company's ability to use less expensive sour and heavy crudes.

The increase in EBIT of $1 million resulted from the increased gross profit of $9 million and increased earnings from equity investments of $7 million partially offset by increased operating expenses of $14 million and higher depreciation, depletion and amortization of $1 million. The increased operating expenses were attributable to increases for maintenance, catalyst and other expenses at the Company's refineries.

Exploration and Production. Exploration and production operations involve the exploration, development and production of natural gas, crude oil, condensate and natural gas liquids.

<TABLE>
<CAPTION>

	Millions of Dollars		
	1998	1997	1996
<S>	<C>	<C>	<C>
Operating revenues..	$ 463.0	$ 490.2	$ 398.5
Depreciation, depletion and amortization.......................	209.2	185.5	158.2
Earnings before interest and income taxes......................	109.8	167.6	135.1
Natural gas production (MMcf per day)..........................	509	436	353
Oil, condensate and natural gas liquids production (bpd)........	15,281	13,580	13,831
Average sales price (dollars):			
Gas (per Mcf)..	$ 1.95	$ 2.40	$ 2.19
Oil, condensate and natural gas liquids (per barrel)......	11.77	18.75	20.46

</TABLE>

1998 Versus 1997. The decrease in operating revenues of $27 million results from lower prices for all products partially offset by increased volumes. Natural gas revenue decreases of $20 million and crude oil, condensate and natural gas liquids revenue decreases of $27 million were partially offset by other increases of $20 million, primarily the result of hedging activities. Average daily net production of natural gas increased by 17% over 1997 and net production of crude oil, condensate and natural gas liquids increased by 13% over the prior year. These volume increases result from Coastal's ongoing successful programs in the Gulf of Mexico, the Texas Coastal Plain and Utah's Uinta Basin.

The EBIT decrease of $58 million results from lower prices of $123 million; increased depreciation, depletion and amortization of $24 million; operating and general expense increases of $8 million and other decreases of $3 million partially offset by higher volumes of $75 million and a $25 million increase from hedging activities. The depreciation, depletion and amortization increase results from increased production. Operating expenses were higher as a result of increased expenses for producing wells.

For the fourth year in a row, Coastal added reserves in 1998 that were more than triple production due to its successful exploration and production programs.

1997 Versus 1996. Operating revenues increased by $92 million as increased volumes and prices for natural gas were partially offset by lower prices and volumes for oil, condensate and natural gas liquids. Natural gas revenue increases of $98 million and other increases of $5 million were partially offset by decreased revenues of $11 million for crude oil, condensate and natural gas liquids. Average daily net production of natural gas increased by 24% over 1996 and net production of crude oil, condensate and natural gas liquids decreased by 2% from the prior year. The volume increase for natural gas resulted from Coastal's ongoing successful programs in the Gulf of Mexico, Texas Coastal Plain and Utah's Uinta Basin.

The increase in EBIT of $33 million resulted from increased volumes of $60 million and higher prices of $23 million partially offset by increased operating expenses of $23 million and higher depreciation, depletion and amortization of $27 million. The increased operating expenses resulted primarily from increased levels of offshore activity and increased production. Increased production volumes and a higher rate accounted for the depreciation, depletion and amortization increase.

Coal. Coal operations include mining, processing and marketing of coal from Company-owned reserves and from other sources, and the brokering of coal for others.

<TABLE>
<CAPTION>

	Millions of Dollars		
	1998	1997	1996
<S>	<C>	<C>	<C>
Operating revenues...	$ 241.7	$ 226.8	$ 713.6
Depreciation, depletion and amortization.......................	14.6	14.1	37.3
Earnings before interest and income taxes......................	17.4	25.3	356.0
Captive and brokered sales (millions of tons)..................	9.0	8.0	17.9

</TABLE>

1998 Versus 1997. The increase in coal revenues of $15 million results primarily from increased volumes and a gain of $3 million from the sale of assets partially offset by lower prices. The segment experienced a 14% increase in captive volumes sold and a 2% decrease in the average sale price per ton as compared to 1997.

The EBIT decrease of $8 million in 1998 results from a nonrecurring favorable resolution of a contingency in 1997 for $9 million, increased operating and general expenses of $13 million and other decreases of $1 million partially offset by the increased revenues of $15 million. The increased operating and general expenses, which include coal costs, are primarily due to the increased volumes sold.

Coastal made significant progress in 1998 toward transforming its coal business from a processing and marketing company using contract mining into an integrated company that mines, processes and sells its own coal.

1997 Versus 1996. The decrease in coal revenues resulted primarily from the sale of the Utah coal mining operations in December 1996 (See Notes 10 and 16 of the Notes to the Consolidated Financial Statements). In addition to the reduction in revenues from operating those mines, the 1996 revenues also included a gain of $272 million from the sale. The segment experienced a 3%

increase in volumes sold from its remaining mines in the Eastern United States and a 4% decrease in the average sales price per ton as compared to 1996.

The decrease in EBIT of $331 million resulted from the $272 million gain noted above and a decrease of $62 million due to not operating the Western mines in 1997 offset by other increases of $3 million. The other increases of $3 million resulted from the favorable resolution of a contingency in 1997 and other increases partially offset by reduced sales of coke from the Company's Aruba refinery.

Power. Power operations include the ownership of, participation in and operation of power projects in the United States and internationally.

	Millions of Dollars		
	1998	1997	1996
Operating revenues	$ 121.1	$ 103.8	$ 92.6
Depreciation, depletion and amortization	3.2	3.1	2.4
Earnings before interest and income taxes	67.8	43.4	41.4

1998 Versus 1997. The increase in operating revenues of $17 million is primarily due to a net benefit of $17 million from the restructuring of power purchase agreements for the Company's Fulton power plant ("Plant"). The net benefit reflects a $23 million reduction in the Plant's carrying value (to estimated fair value following the restructuring) and deferral of certain proceeds to cover estimated future costs. The EBIT increase of $24 million reflects this $17

million and increased income from equity investments of $7 million. The increased equity income in 1998 can be attributed to Coastal's successful expansion of its power operations in North America, Latin America and Asia.

Coastal added 434 megawatts of operating capacity (292 megawatts net to Coastal's interest), during 1998 through both the acquisition of interests in existing plants and new projects.

1997 Versus 1996. The increase in operating revenues of $11 million resulted primarily from increased revenues related to the El Salvador operations partially offset by a development fee received in 1996. The increase in EBIT of $2 million resulted from increased equity earnings of $12 million offset by a $4 million development fee received in 1996, a $2 million decrease at a domestic cogeneration plant due to mechanical problems and increased administrative and development expenses of $4 million related to the operations of joint venture projects. The equity income increase was due primarily to improved results from both domestic and foreign plants, some of which were operated only a partial year in 1996.

Corporate and Other. Other operations involve real estate and corporate income and expense not allocated to the operating segments.

	Millions of Dollars		
	1998	1997	1996
Operating revenues	$ 23.0	$ 29.4	$ 32.7
Depreciation, depletion and amortization	7.0	4.1	6.0
Loss before interest and income taxes	(88.7)	(70.4)	(74.1)

1998 Versus 1997. Operating revenues decreased by $6 million, primarily as the result of the sale of certain real estate properties in 1997. The increased loss before interest and income taxes of $18 million is attributable to dividends on the Company-obligated mandatory redemption preferred securities of a consolidated trust of $16 million and other of $2 million.

1997 Versus 1996. The $3 million decrease in operating revenues resulted primarily from the sale of certain real estate properties in 1997. The reduced loss before earnings and income taxes of $4 million resulted primarily from increased interest income.

Interest and Debt Expense

1998 Versus 1997. The interest and debt expense decrease of $13 million results from reduced average interest rates, reduced interest associated with regulatory matters and increased capitalized interest partially offset by increases due to higher average debt.

1997 Versus 1996. Interest and debt expense decreased by $61 million in 1997 due to lower average debt and a lower average interest rate.

Taxes on Income

Income taxes fluctuated as a result of changing levels of income before taxes and changes in the effective federal income tax rate. The effective federal income tax rates were primarily affected by the exclusions for foreign investments and certain domestic joint ventures.

Discontinued Operations

The discontinued operations result from the Company pursuing the disposition of its 50% owned trucking operation as described in Note 13 of the Notes to Consolidated Financial Statements.

Extraordinary Items

The extraordinary items, net of income taxes, resulted from the early retirement of debt in 1997 and 1996 and the discontinuation of regulatory accounting in 1996. See Note 14 of the Notes to Consolidated Financial Statements.

INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholders
The Coastal Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of The Coastal Corporation and subsidiaries as of December 31, 1998 and 1997, and the related consolidated statements of operations, common stock and other stockholders' equity and cash flows for each of the three years in the period ended December 31, 1998. Our audits also included the financial statement schedules listed in the Index at Item 14(a)2. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of The Coastal Corporation and subsidiaries as of December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP

Houston, Texas
February 4, 1999

THE COASTAL CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED OPERATIONS
(Millions of Dollars Except Per Share)

<TABLE>
<CAPTION>

	Year Ended December 31,		
	1998	1997	1996
<S>	<C>	<C>	<C>
OPERATING REVENUES..	$ 7,368.2	$ 9,730.1	$ 12,166.9
OPERATING COSTS AND EXPENSES			
Purchases..	4,376.8	6,863.5	8,979.8
Operating and general expenses..............................	1,674.9	1,700.4	1,786.9
Depreciation, depletion and amortization....................	443.2	433.5	453.6
	6,494.9	8,997.4	11,220.3
OTHER INCOME - NET..	71.2	111.8	97.0
EARNINGS BEFORE INTEREST AND INCOME TAXES......................	944.5	844.5	1,043.6
OTHER EXPENSES			
Interest and debt expense...................................	294.9	307.5	368.3
Taxes on income...	166.7	138.3	167.3
EARNINGS FROM CONTINUING OPERATIONS BEFORE EXTRAORDINARY ITEMS..................................	482.9	398.7	508.0
DISCONTINUED OPERATIONS - NET OF INCOME TAXES			
Loss from operations.......................................	(3.5)	(6.6)	(7.8)
Estimated loss on disposal.................................	(35.0)	-	-

EARNINGS BEFORE EXTRAORDINARY ITEMS	444.4	392.1	500.2
EXTRAORDINARY ITEMS - NET OF INCOME TAXES			
Loss on early extinguishment of debt	-	(90.6)	(12.0)
Discontinuation of regulatory accounting	-	-	(85.6)
NET EARNINGS	444.4	301.5	402.6
DIVIDENDS ON PREFERRED STOCK	6.0	17.4	17.4
NET EARNINGS AVAILABLE TO COMMON STOCKHOLDERS	$ 438.4	$ 284.1	$ 385.2
BASIC EARNINGS PER SHARE			
From continuing operations before extraordinary items	$ 2.24	$ 1.80	$ 2.33
Discontinued operations	(.18)	(.03)	(.04)
Extraordinary items	-	(.43)	(.46)
NET BASIC EARNINGS PER SHARE	$ 2.06	$ 1.34	$ 1.83
DILUTED EARNINGS PER SHARE			
From continuing operations before extraordinary items	$ 2.21	$ 1.77	$ 2.30
Discontinued operations	(.18)	(.03)	(.04)
Extraordinary items	-	(.42)	(.46)
NET DILUTED EARNINGS PER SHARE	$ 2.03	$ 1.32	$ 1.80

</TABLE>

See Notes to Consolidated Financial Statements.

THE COASTAL CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET
(Millions of Dollars)

<TABLE>
<CAPTION>

<S>	December 31, 1998 <C>	1997 <C>
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 106.9	$ 20.5
Receivables, less allowance for doubtful accounts $15.9 million (1998) and $16.6 million (1997)	1,142.8	1,538.0
Inventories	499.5	684.7
Prepaid expenses and other	220.6	252.7
Total current assets	1,969.8	2,495.9
PROPERTY, PLANT AND EQUIPMENT - AT COST		
Natural gas systems	6,069.2	5,887.6
Refining, crude oil and chemical facilities	2,424.2	2,254.8
Gas and oil properties - at full-cost	2,870.8	2,123.4
Other	366.6	395.0

	11,730.8	10,660.8
Accumulated depreciation, depletion and amortization	3,706.9	3,539.2
	8,023.9	7,121.6
OTHER ASSETS		
Goodwill	470.8	489.8
Investments - equity method	970.8	752.6
Other	868.8	779.8
	2,310.4	2,022.2
	$ 12,304.1	$ 11,639.7

</TABLE>

See Notes to Consolidated Financial Statements.

THE COASTAL CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET
(Millions of Dollars)

<TABLE>
<CAPTION>

	December 31,	
	1998	1997
<S>	<C>	<C>
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Notes payable	$ 87.0	$ 114.0
Accounts payable	1,488.0	2,074.0
Accrued expenses	305.0	270.7
Current maturities on long-term debt	126.5	42.0
Total current liabilities	2,006.5	2,500.7
DEBT		
Long-term debt, excluding current maturities	3,999.3	3,663.2
DEFERRED CREDITS AND OTHER		
Deferred income taxes	1,717.7	1,579.4
Other deferred credits	704.8	514.0
	2,422.5	2,093.4
PREFERRED STOCK		
Company-obligated mandatory redemption preferred securities of a consolidated trust	300.0	-
Issued by subsidiaries	100.0	100.0
	400.0	100.0
COMMON STOCK AND OTHER STOCKHOLDERS' EQUITY		
Cumulative preferred stock (with aggregate liquidation preference of $7.7 million)	-	2.6
Class A common stock - Issued (1998 - 354,058 shares; 1997 - 366,315 shares)	.1	.1
Common stock - Issued (1998 - 216,764,580 shares; 1997 - 110,117,191 shares)	72.2	36.7
Additional paid-in capital	1,016.2	1,243.6

Retained earnings	2,519.8	2,131.9
	3,608.3	3,414.9
Less common stock in treasury - at cost (1998 - 4,395,654 shares; 1997 - 4,395,867 shares)	132.5	132.5
	3,475.8	3,282.4
	$ 12,304.1	$ 11,639.7

</TABLE>

See Notes to Consolidated Financial Statements.

THE COASTAL CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CASH FLOWS
(Millions of Dollars)

<TABLE>
<CAPTION>

	Year Ended December 31,		
	1998	1997	1996
<S>	<C>	<C>	<C>
NET CASH FLOW FROM OPERATING ACTIVITIES			
Earnings from continuing operations before extraordinary items	$ 482.9	$ 398.7	$ 508.0
Add (subtract) items not requiring (providing) cash:			
Depreciation, depletion and amortization	449.4	436.6	455.7
Deferred income taxes	151.7	73.9	60.0
Gain from sale of Utah coal mining operations	-	-	(272.3)
Amortization of producer contract reformation costs	-	-	25.6
Undistributed earnings from equity investments	(41.2)	(43.0)	(15.2)
Working capital and other changes, excluding changes relating to cash and non-operating activities:			
Accounts receivable	395.2	248.5	(670.2)
Inventories	185.1	418.2	(387.2)
Prepaid expenses and other	31.0	12.3	.4
Accounts payable	(573.4)	(350.1)	796.9
Accrued expenses	30.9	(56.6)	61.0
Other	34.7	(161.6)	11.9
	1,146.3	976.9	574.6
CASH FLOW FROM INVESTING ACTIVITIES			
Purchases of property, plant and equipment	(1,404.0)	(996.7)	(880.8)
Proceeds from sale of property, plant and equipment	98.5	84.1	79.4
Additions to investments	(255.4)	(193.8)	(114.2)
Proceeds from investments	59.9	71.5	25.9
Proceeds from sale of Utah coal mining operations	-	-	610.1
Recovery of gas supply prepayments	-	-	.3
Net from discontinued operations	9.3	(16.0)	(13.2)
	(1,491.7)	(1,050.9)	(292.5)
CASH FLOW FROM FINANCING ACTIVITIES			
Increase (decrease) in short-term notes	123.0	259.0	(318.2)
Redemption of preferred stock	(200.0)	-	(.6)
Proceeds from issuing common stock	5.5	7.3	14.7
Proceeds from issuing stock of subsidiaries	-	-	105.0
Proceeds from long-term debt issues	432.2	943.4	590.7
Proceeds from issuing Company-obligated mandatory redemption preferred securities of a consolidated trust	300.0	-	-
Payments to retire long-term debt	(172.4)	(1,161.8)	(566.2)
Dividends paid	(56.5)	(59.7)	(59.6)

	431.8	(11.8)	(234.2)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	86.4	(85.8)	47.9
Cash and cash equivalents at beginning of year...............	20.5	106.3	58.4
Cash and cash equivalents at end of year....................	$ 106.9	$ 20.5	$ 106.3

</TABLE>

See Notes to Consolidated Financial Statements.

THE COASTAL CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED COMMON STOCK AND
OTHER STOCKHOLDERS' EQUITY
(Thousands of Shares and Millions of Dollars)

<TABLE>
<CAPTION>

	Year Ended December 31,					
	1998		1997		1996	
	Shares	Amount	Shares	Amount	Shares	Amount
<S>	<C>	<C>	<C>	<C>	<C>	<C>
PREFERRED STOCK, PAR VALUE 33-1/3(cent) PER SHARE, AUTHORIZED 50,000,000 SHARES CUMULATIVE CONVERTIBLE PREFERRED:						
$1.19, Series A: Beginning balance..	58	$ -	60	$ -	61	$ -
Converted to common................	(2)	-	(2)	-	(1)	-
Ending balance...................	56	-	58	-	60	-
$1.83, Series B: Beginning balance..	68	-	74	-	79	.1
Converted to common................	(7)	-	(6)	-	(5)	(.1)
Ending balance...................	61	-	68	-	74	-
$5.00, Series C: Beginning balance..	30	-	32	-	33	-
Converted to common................	(2)	-	(2)	-	(1)	-
Ending balance...................	28	-	30	-	32	-
CUMULATIVE PREFERRED:						
$2.125, Series H, liquidation amount of $25 per share:						
Beginning balance..................	8,000	2.6	8,000	2.6	8,000	2.6
Redeemed...........................	(8,000)	(2.6)	-	-	-	-
Ending balance.....................	-	-	8,000	2.6	8,000	2.6
CLASS A COMMON STOCK, PAR VALUE 33-1/3(cent) PER SHARE, AUTHORIZED 2,700,000 SHARES						
Beginning balance..................	366	.1	382	.1	404	.1
Converted to common................	(13)	-	(17)	-	(35)	-
Conversion of preferred stock and exercise of stock options..........	1	-	1	-	13	-
Ending balance..................	354	.1	366	.1	382	.1
COMMON STOCK, PAR VALUE 33-1/3(cent) PER SHARE, AUTHORIZED 250,000,000 SHARES						

Beginning balance	110,117	36.7	109,756	36.6	109,168	36.4
Conversion of preferred stock	63	-	47	-	34	-
Conversion of Class A common stock	13	-	17	-	35	-
Two-for-one stock split	106,274	35.4	-	-	-	-
Exercise of stock options	298	.1	297	.1	519	.2
Ending balance	216,765	72.2	110,117	36.7	109,756	36.6
ADDITIONAL PAID-IN CAPITAL						
Beginning balance		1,243.6		1,239.6		1,225.0
Exercise of stock options		5.4		4.0		14.6
Two-for-one stock split		(35.4)		-		-
Redemption of Series H preferred stock		(197.4)		-		-
Ending balance		1,016.2		1,243.6		1,239.6
RETAINED EARNINGS						
Beginning balance		2,131.9		1,890.1		1,547.1
Net earnings for period		444.4		301.5		402.6
Cash dividends on preferred stock		(6.0)		(17.4)		(17.4)
Cash dividends on Class A common stock, 21.38(cent)(1998), 18(cent)(1997) and 18(cent)(1996) per share		(.1)		(.1)		(.1)
Cash dividends on common stock, 23.75(cent)(1998), 20(cent)(1997) and 20(cent)(1996) per share		(50.4)		(42.2)		(42.1)
Ending balance		2,519.8		2,131.9		1,890.1
LESS TREASURY STOCK - AT COST	4,396	132.5	4,396	132.5	4,395	132.5
TOTAL		$3,475.8		$3,282.4		$3,036.5

</TABLE>

See Notes to Consolidated Financial Statements.

THE COASTAL CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

Principles of Consolidation. The consolidated financial statements include accounts of the Company and its wholly owned subsidiaries, after eliminating all significant intercompany transactions. The equity method of accounting is used for investments in which the Company has a 20% to 50% voting interest and exercises significant influence. The equity method is also used for investments in limited partnerships in which the Company has an interest of more than 5%. Other investments in which the Company has less than a 20% voting interest are accounted for by the cost method.

Statement of Cash Flows. For purposes of this statement, cash equivalents include time deposits, certificates of deposit and all highly liquid instruments with original maturities of three months or less. Cash flows of a hedging instrument that is accounted for as a hedge of an identifiable transaction are classified in the same category as the cash flows from the item being hedged. The Company made cash payments for interest and financing fees (net of amounts capitalized) of $291.6 million, $275.7 million and $386.0 million in 1998, 1997 and 1996, respectively. Cash payments for income taxes amounted to $42.4 million, $63.6 million and $57.2 million for 1998, 1997 and 1996, respectively.

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires the Company to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Actual results could differ from the estimates and assumptions used.

Inventories. Inventories of refined products and crude oil are accounted by the first-in, first-out cost method or market, if lower. Inventories of natural gas are accounted for at average cost. Inventories of coal are accounted for at average cost, or market, if lower. Inventories of materials and supplies are accounted for at average cost.

Hedges. The Company frequently enters into swaps, futures and other contracts to hedge the price risks associated with inventories, commitments and certain anticipated transactions. The Company defers the impact of changes in the market value of these contracts until such time as the hedged transaction is completed. At that time, the impact of the changes in the fair value of these contracts is recognized in income. The Company also enters into interest rate and foreign currency swaps to manage interest rates and foreign currency exchange risk. Income and expense related to interest rate swaps is accrued as interest rates change and is recognized in income over the life of the agreement. Gains or losses from foreign currency swaps are deferred and are recognized as payments are made on the related foreign currency denominated debt. Such gains and losses are essentially offset by gains or losses on the related debt.

To qualify as a hedge, the item to be hedged must expose the Company to price, interest rate or foreign currency exchange rate risk and the hedging instrument must reduce that exposure. Any contracts held or issued that did not meet the requirements of a hedge would be recorded at fair value in the balance sheet and any changes in that fair value recognized in income. If a contract designated as a hedge of price risk or foreign currency exchange risk is terminated, the associated gain or loss is deferred and recognized in income in the same manner as the hedged item. Also, a contract designated as a hedge of an anticipated transaction that is no longer likely to occur would be recorded at fair value and the associated changes in fair value recognized in income. The gain or loss associated with a terminated interest rate swap that has been designated as a hedge of interest rate risk will continue to be recognized in interest and debt expense over the life of the agreement.

Property, Plant and Equipment. Property additions include acquisition costs, administrative costs and, where appropriate, capitalized interest allocable to construction. Capitalized interest amounted to $26.9 million, $15.5 million and $8.0 million in 1998, 1997 and 1996, respectively. All costs incurred in the acquisition, exploration and development of gas and oil properties, including unproductive wells, are capitalized under the full-cost method of accounting. Such costs include the costs of all unproved properties and internal costs directly related to acquisition and exploration activities. All other general and administrative costs, as well as production costs, are expensed as incurred.

Depreciation, depletion and amortization ("DD&A") of gas and oil properties are provided on the unit-of-production basis whereby the unit rate for DD&A is determined by dividing the total unrecovered carrying value

of gas and oil properties plus estimated future development costs by the estimated proved reserves included therein, as estimated by Company engineers for 1998 and reviewed by independent engineers. Estimated proved reserves for 1997 were estimated by the Company's independent engineers. The average amortization rate per equivalent unit of a thousand cubic feet of gas production for oil and gas operations was $.89 for 1998, $.91 for 1997 and $.88 for 1996. Unamortized costs of proved properties are subject to a ceiling which limits such costs to the estimated future net cash flows from proved gas and oil properties, net of related income tax effects, discounted at 10 percent. If the unamortized costs are greater than this ceiling, any excess will be charged to DD&A expense. No such charge was required in the periods presented. Provisions for depletion of coal properties, including exploration and development costs, are based upon estimates of recoverable reserves using the unit-of-production method. Provision for depreciation of other property is primarily on a straight-line basis over the estimated useful life of the properties. The annual rates of depreciation are as follows:

Refining, crude oil and chemical facilities .... 3.0% - 20.0%

Gas systems..	1.2% - 10.0%
Coal facilities....................................	5.0% - 33.3%
Power facilities	2.9% - 33.3%
Transportation equipment...........................	5.0% - 33.3%
Office and miscellaneous equipment.................	2.5% - 20.0%
Buildings and improvements.........................	1.3% - 20.0%

Costs of minor property units (or components thereof) retired or abandoned are charged or credited, net of salvage, to accumulated depreciation, depletion and amortization. Gain or loss on sales of major property units is credited or charged to income.

Goodwill. Goodwill, which primarily relates to the acquisitions of American Natural Resources Company and CIG, amounted to $470.8 million at December 31, 1998, and is being amortized on a straight-line basis over a 40-year period. Amortization expense charged to operations was approximately $19.0 million for 1998, 1997 and 1996, respectively. As warranted by facts and circumstances, the Company periodically assesses the recoverability of the cost of goodwill from future operating income.

Income Taxes. The Company follows the liability method of accounting for deferred income taxes as required by the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."

Revenue Recognition. The Company's subsidiaries recognize revenues for the sale of their respective products in the period of delivery. Revenues for services are recognized in the period the services are provided.

Currency Translation. The U.S. dollar is the functional currency for substantially all the Company's foreign operations. For those operations, all gains and losses from currency translations are included in income currently.

Earnings Per Share. Basic earnings per common share amounts are calculated using the average number of common and Class A common shares outstanding during each period. Diluted earnings per share assumes conversion of dilutive convertible preferred stocks and exercise of all stock options having exercise prices less than the average market price of the common stock using the treasury stock method.

Basic and diluted earnings per share amounts and average shares entering into the computation for 1998 and prior years reflect the two-for-one stock split of the Company's common stock declared on May 7, 1998. See Note 8 of the Notes to Consolidated Financial Statements.

Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" ("FAS 71"). The interstate natural gas pipelines and certain storage subsidiaries are subject to the regulations and accounting procedures of the Federal Energy Regulatory Commission ("FERC"). These subsidiaries historically followed the reporting and accounting requirements of FAS 71. Effective November 1, 1996, these subsidiaries discontinued application of FAS 71. This accounting change has no direct effect on either the subsidiaries' ability to include the previously deferred items in future rate proceedings or on their ability to collect the rates set thereby. The Company believes this accounting change results in financial reporting which better reflects the results of

operations in the economic environment in which these subsidiaries operate. Further, the Company has reexamined the useful lives of certain assets corresponding to these subsidiaries. During 1997, the depreciation rates associated with these assets were revised, which had the effect of increasing "Earnings from continuing operations before extraordinary items" and "Net earnings" by $19.0 million ($.09 per share) in 1998 and $13.4 million ($.06 per share) in 1997.

Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income" ("FAS 130"). The Company adopted FAS 130 in 1998. The application of the new standard did not have a material effect on the Company's consolidated financial statements as the Company currently does not have any material items of other comprehensive income.

Statement of Financial Accounting Standards No. 131, "Disclosures about Segments of an Enterprise and Related Information" ("FAS 131"). The Company adopted FAS 131 in 1998. The Company's disclosures for 1998 and prior years have been revised in accordance with this statement.

Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" ("FAS 132"). The Company adopted FAS 132 in 1998. The Company's disclosures for 1998 and prior years have been revised in accordance with this statement.

Statement of Position 98-1 ("SOP 98-1"). The Accounting Standards Executive Committee of the American Institute of Certified Public Accountants ("AICPA") issued SOP 98-1 on Accounting for the Costs of Computer Software Developed or Obtained for Internal Use, which was adopted by the Company in 1998. The application of the new statement did not have a material effect on the Company's consolidated results of operations, financial position or cash flows.

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). The Financial Accounting Standards Board ("FASB") has issued FAS 133 to be effective for all fiscal quarters of fiscal years beginning after June 15, 1999. FAS 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. The accounting for changes in the fair value of a derivative will depend on the intended use of the derivative and the resulting designation. The Company is currently evaluating the impact of FAS 133.

Emerging Issues Task Force Issue No. 98-10. The FASB Emerging Issues Task Force Issue No. 98-10, to be effective for years beginning after December 15, 1998, states that energy trading contracts (as defined) should be marked to market with the gains and losses included in earnings and separately disclosed in the financial statements or footnotes thereto. The Company does not believe the application of Issue No. 98-10 will have a material effect on its consolidated financial statements.

Statement of Position 98-5 ("SOP 98-5"). The AICPA has issued SOP 98-5, to be effective for periods beginning after December 15, 1998. SOP 98-5 provides guidance on accounting for costs incurred to open new facilities, conduct business in new territories or otherwise commence some new operation. The application of SOP 98-5 is not expected to have a material effect on the Company's consolidated financial statements.

Euro Conversion. In January 1999, certain countries of the European Union adopted the Euro as their legal common currency. This conversion to the Euro is not expected have a material effect on the Company's consolidated results of operations, financial position or cash flows as the Company does not have significant European operations.

Reclassification of Prior Period Statements. Prior period financial statements have been restated to report the Company's 50% owned trucking operation as a discontinued operation. In addition, certain minor reclassifications have been made to conform with current reporting practices. The effect of the reclassifications was not material to the Company's consolidated results of operations, financial position or cash flows.

Note 2. Inventories

Inventories at December 31 were (Millions of Dollars):

<TABLE>
<CAPTION>

<S>	1998 <C>	1997 <C>
Refined products, crude oil and chemicals	$ 306.9	$ 492.3
Natural gas in underground storage	32.0	40.5
Coal, materials and supplies	160.6	151.9
	$ 499.5	$ 684.7

</TABLE>

Elements included in inventory cost are material, labor and manufacturing expenses.

Note 3. Investments

The Company has interests in corporations and partnerships which are accounted for on an equity basis. These investments, included in Other Assets, are Great Lakes Gas Transmission Limited Partnership (50% interest), which operates an interstate pipeline system; Engage Energy US, L.P. and Engage Energy Canada, L.P.("Engage") (50% interest), which market natural gas and electricity; Iroquois Gas Pipeline System, L.P. (16% interest), which operates a natural gas pipeline; Empire State Pipeline (50% interest), which operates a natural gas pipeline; Javelina Company (40% interest), which operates a gas processing plant in Corpus Christi, Texas; Eagle Point Cogeneration Partnership (50% interest), which operates a cogeneration facility in New Jersey; Alliance Pipeline Limited Partnership (14.4% interest), which is constructing a 1,900-mile natural gas pipeline; Midland Cogeneration Venture (20.4% interest), which operates a cogeneration plant in Michigan; and several pipeline, power and other ventures. The Company's investment in these entities, including advances, amounted to $970.8 million and $752.6 million at December 31, 1998 and 1997, respectively. The Company's equity in income of the investments, included in Other Income-Net, was $124.3 million, $137.5 million and $118.1 million in 1998, 1997 and 1996, respectively, while dividends and partnership distributions received amounted to $83.1 million, $94.5 million and $102.9 million in 1998, 1997 and 1996, respectively.

Summarized financial information of these entities is as follows (Millions of Dollars):

<TABLE>
<CAPTION>

	December 31, 1998	December 31, 1997
<S>	<C>	<C>
Current assets	$ 1,388.2	$ 1,430.4
Noncurrent assets	5,948.8	5,365.7
	$ 7,337.0	$ 6,796.1
Current liabilities	$ 1,093.1	$ 1,288.0
Noncurrent liabilities	3,348.2	3,245.6
Deferred credits	225.0	228.0
Equity	2,670.7	2,034.5
	$ 7,337.0	$ 6,796.1

</TABLE>

<TABLE>
<CAPTION>

	Year Ended December 31, 1998	1997	1996
<S>	<C>	<C>	<C>
Revenues	$ 7,631.4	$ 5,302.1	$ 2,012.6
Operating income	563.2	627.5	616.1
Net income	306.5	353.4	296.5

</TABLE>

Note 4. Debt

Long-Term Debt - Balances at December 31 were (Millions of Dollars):

<TABLE>
<CAPTION>

	1998	1997
The Coastal Corporation:		
Notes payable (revolving credit agreements)	$ 125.0	$ 125.0
Senior notes:		
10.375%, due 2000	121.3	121.3
10%, due 2001	84.0	83.9
8.75%, due 1999	150.0	150.0
8.125%, due 2002	249.7	249.6
Senior debentures:		
10.25%, due 2004	37.7	37.7
10.75%, due 2010	56.4	56.4
9.75%, due 2003	102.1	102.1
9.625%, due 2012	149.3	149.3
7.75%, due 2035	149.9	149.9
7.42%, due 2037	200.0	200.0
6.7%, due 2027	200.0	200.0
6.5%, due 2008	199.8	-
6.95%, due 2028	199.4	-
	2,024.6	1,625.2
Subsidiary companies:		
Notes payable (term credit facilities)	184.3	244.3
Notes payable (revolving credit agreements)	609.0	682.6
Notes payable (project financings), due 2006-2011	59.6	51.0
Debentures, 6.85% to 10%, due 2005-2037	777.5	777.4
Other, due 2000-2028	70.8	74.7
	1,701.2	1,830.0
Amount reclassified from short-term debt	400.0	250.0
Total long-term debt	4,125.8	3,705.2
Less current maturities	126.5	42.0
	$ 3,999.3	$ 3,663.2

</TABLE>

- At December 31, 1998, amounts available under long-term credit agreements with banks totaled $1,374.3 million, including $125.0 million available to The Coastal Corporation. Loans under these agreements bear interest at money market-related rates (weighted average 5.743% at December 31, 1998). Annual commitment fees range up to .30% payable on the unused portion of the applicable facility. At December 31, 1998, $918.3 million was outstanding and $45.1 million of the unused amount was dedicated to a specific use.

The subsidiary project financing notes bear interest at money market-related rates.

The Company has $150.0 million of 8.75% Senior Notes which are due May 15, 1999. The financial statements at December 31, 1998 reflect this amount as long-term, based on the availability of committed credit lines with maturities in excess of one year and the Company's intent to refinance the debt on a long-term basis.

In February 1999, the Company completed a public offering of $200.0 million of 6.375% senior debentures due 2009. The net proceeds from the sale were used to repay floating rate indebtedness of a subsidiary under a revolving credit facility.

Various agreements contain restrictive covenants which, among other things, limit dividends by certain subsidiaries and additional indebtedness of certain subsidiaries. At December 31, 1998, net assets of consolidated subsidiaries amounted to approximately $6.8 billion, of which $653.0 million was restricted by such provisions.

Maturities. The aggregate amounts of long-term debt maturities for the five years following 1998 are (Millions of Dollars):

1999	$126.5	2002	$387.2
2000	$206.6	2003	$116.3
2001	$686.1		

Notes Payable. At December 31, 1998, Coastal and its subsidiaries had $487.0 million of outstanding indebtedness to banks under short-term lines of credit, compared to $364.0 million at December 31, 1997. As of December 31, 1998, the Company's financial statements reflected $400.0 million of short-term borrowings which had been reclassified as long-term, based on the availability of committed credit lines with maturities in excess of one year and the Company's intent to maintain such amounts as long-term borrowings. There was a similar reclassification of $250.0 million as of December 31, 1997. The weighted average interest rates were 6.07% and 6.31% at December 31, 1998 and 1997, respectively. As of December 31, 1998, $649.0 million was available to be drawn under short-term credit lines.

Restrictions on Payment of Dividends. Under the terms of the most restrictive of the Company's financing agreements, approximately $686.1 million of retained earnings was available at December 31, 1998, for payment of dividends on the Company's common and preferred stocks.

Guarantees. Coastal and certain subsidiaries have guaranteed specific obligations of several unconsolidated affiliates. Affiliates are generally not required to collateralize their contingent liabilities to the Company. At December 31, 1998, the Company had guaranteed construction financings of two partially owned partnerships. The Company's proportionate share of the outstanding principal balance under these guarantees was $94.5 million at December 31, 1998. These loans are expected to be refinanced on a non-recourse basis in 1999. The Company and a partner have issued a number of guarantees related to the operations of Engage. Pursuant to an equalization agreement with the partner, each party has agreed to reimburse the other in the event there are disproportionate payments under their respective guarantees. As of December 31, 1998, the Company's share of such guarantees was $521.3 million; the actual affiliate liabilities related to these guarantees was $95.2 million. Other guarantees and indemnities related to obligations of unconsolidated affiliates amounted to approximately $227.5 million as of December 31, 1998. The Company is of the opinion that its unconsolidated affiliates will be able to perform under their respective financings and other obligations and that no payments will be required and no losses will be incurred under such guarantees and indemnities.

Note 5. Leases and Commitments

The Company leases property, plant and equipment under various operating leases, certain of which contain renewal and purchase options and residual value guarantees. Such residual value guarantees amount to approximately $303.4 million. Rental expense amounted to approximately $86.0 million, $95.3 million and $92.7 million in 1998, 1997 and 1996, respectively, excluding leases covering natural resources. Aggregate minimum lease payments under existing noncapitalized long-term leases are estimated to be $87.2 million, $87.5 million, $91.7 million, $83.7 million, and $87.1 million for the years 1999-2003, respectively, and $577.9 million thereafter.

Note 6. Preferred Stock of Subsidiaries

Company-Obligated Mandatory Redemption Preferred Securities of a Consolidated Trust. On May 13, 1998, Coastal completed a public offering of 12,000,000 Coastal-obligated mandatory redemption preferred securities through an affiliate, Coastal Finance I, a business trust (the "Trust"), for $300 million in cash. The Trust holds debt securities of Coastal purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375% of the liquidation amount of $25 per preferred security. The proceeds were used to refinance borrowings incurred to finance the redemption of the Series H Preferred Stock discussed in Note 8 of the Notes to the Consolidated Financial Statements and to repay certain outstanding subsidiary indebtedness. The preferred securities are mandatorily redeemable on the maturity date, May 13, 2038, and may be redeemed at the Company's option on or after May 13, 2003, or earlier if certain events occur. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption.

Preferred Stock. Shares and aggregate redemption value of mandatory redemption preferred stock outstanding, excluding shares redeemable within one year, were (Thousands of Shares and Millions of Dollars):

<TABLE>
<CAPTION>

	Shares	Value
<S>	<C>	<C>
Balance, December 31, 1995	6	$ .6
Redemptions	(6)	(.6)
Balance, December 31, 1996	-	-
Redemptions	-	-
Balance, December 31, 1997	-	-
Redemptions	-	-
Balance, December 31, 1998	-	$ -

</TABLE>

Coastal Securities Company Limited ("Coastal Securities"), a wholly owned subsidiary, issued 4,000,000 shares of preferred stock in 1996 for $100 million in cash. Quarterly cash dividends are being paid on the preferred stock at a rate based on the London Interbank Offered Rate ("LIBOR"). The preferred shareholders are also entitled to participating dividends based on certain refining margins. Coastal Securities may redeem the preferred stock on or after December 31, 1999 for cash. Also, on or after December 31, 1999 but prior to December 31, 2000, Coastal Securities may elect to redeem the preferred stock by issuing unsecured convertible debentures.

Note 7. Financial Instruments and Risk Management

The Company's operations involve managing market risks related to changes in interest rates, foreign exchange rates and commodity prices. Derivative financial instruments, specifically swaps and other contracts, are used to reduce and manage those risks. The Company does not currently hold or issue financial instruments for trading purposes.

Interest Rate Swaps. The Company has entered into a number of interest rate swap agreements designated as a partial hedge of the Company's portfolio of variable rate debt. The purpose of these swaps is to fix interest rates on variable rate debt and reduce certain exposures to interest rate fluctuations. At December 31, 1998, the Company had interest rate swaps with a notional amount of $22.5 million, and a portfolio of variable rate debt outstanding in the amount of $1,515.7 million. Under these agreements, Coastal will pay the counterparties interest at a weighted average fixed rate of 6.7%, and the counterparties will pay Coastal interest at a variable rate equal to LIBOR. The weighted average LIBOR rate applicable to these agreements was 5.36% at December 31, 1998. The notional amounts do not represent amounts exchanged by the parties, and thus are not a measure of exposure of the Company. The amounts exchanged are normally based on the notional amounts and other terms of the swaps. The weighted average variable rates are subject to change over time as LIBOR fluctuates. Terms expire at various dates through the year 2011.

Neither the Company nor the counterparties, which are prominent bank institutions, are required to collateralize their respective obligations under these swaps. Coastal is exposed to loss if one or more of the counterparties default. At December 31, 1998, Coastal had no exposure to credit loss on interest rate swaps. The Company does not believe that any reasonably likely change in interest rates would have a material adverse effect on the financial position, the results of operations or cash flows of the Company. All interest rate and currency swaps are reviewed with, and, when necessary, are approved by the Company's Board of Directors.

Other Derivatives. The Company and its subsidiaries also frequently enter into swaps and other contracts to hedge the price risks associated with inventories, commitments and certain anticipated transactions. The swaps and other contracts are with established energy companies and major financial institutions. The Company believes its credit risk is minimal on these transactions, as the counterparties are required to meet stringent credit standards. There is continuous day-to-day involvement by senior management in the hedging decisions, operating under resolutions adopted by each subsidiary's board of directors.

Fair Value of Financial Instruments. The estimated fair value amounts of the Company's financial instruments have been determined by the Company, using appropriate market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value, thus, the estimates provided herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

<TABLE>
<CAPTION>

	(Millions of Dollars)			
	Dec. 31, 1998		Dec. 31, 1997	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
<S>	<C>	<C>	<C>	<C>
Nonderivatives:				
Financial assets:				
Cash and cash equivalents..................	$ 106.9	$ 106.9	$ 20.5	$ 20.5
Notes receivable...........................	248.1	271.3	222.3	241.1
Investments................................	64.0	64.0	56.8	56.8
Financial liabilities:				
Short-term debt...............................	87.0	87.0	114.0	114.0
Long-term debt	4,125.8	4,423.0	3,705.2	4,024.0
Company-obligated mandatory redemption preferred securities of a consolidated trust	300.0	295.6	-	-
Preferred stock - issued by subsidiaries.......	100.0	100.0	100.0	100.0
Derivatives relating to:				
Commodity swaps loss..........................	-	-	-	-
Debt:				
Interest rate swaps loss	-	1.7	-	0.2

</TABLE>

The estimated value of the Company's notes receivable, long-term debt, Company-obligated mandatory redemption preferred securities of a consolidated trust and preferred stock - issued by subsidiaries is based on interest rates at December 31, 1998 and 1997, respectively, for new issues with similar remaining maturities. The fair value of investments are based on market prices at December 31, 1998 and 1997. The fair market value of the Company's interest rate swaps is based on the estimated termination values at December 31, 1998 and 1997, respectively.

Note 8. Common and Preferred Stock

On May 7, 1998, the Board of Directors of Coastal authorized a two-for-one stock split of the Coastal common stock. On July 1, 1998, stockholders of record received one additional share of common stock for each share of common stock and/or Class A common stock held of record on May 29, 1998. The stock split has been reflected in the accompanying financial statements, and all applicable references as to the number of common shares and per share information have been restated. Appropriate adjustments have been made in the conversion ratios of shares of convertible preferred stock and in the exercise price and number of shares subject to stock options. Effective with the stock split, the annual cash dividend rate on the common stock is $.25 per share.

On April 15, 1998, the Company redeemed all 8,000,000 outstanding shares of its $2.125 Cumulative Preferred Stock, Series H. Redemption price for the Series H stock was $25 per share plus accrued dividends of $.182986 to April 15, 1998.

Executives, directors and other key employees have been granted options to purchase common shares under stock option plans adopted in 1990, 1994, 1996, 1997 and 1998. Under each plan, the option price equals the fair market value of the common shares on the date of grant. Options vest cumulatively at rates ranging from 15% to 331/3% of the option shares on each anniversary date of the date of grant beginning with the first or second anniversary. The options, which expire either five years or ten years from the grant date, do not carry any stock appreciation rights.

The following table presents a summary of stock option transactions for the three years ended December 31, 1998:

<TABLE>
<CAPTION>

	Common Shares	Class A Common Shares	Average Option Price Per Share
<S>	<C>	<C>	<C>
December 31, 1995	4,329,252	14,780	$ 14.08
Granted	1,333,000	-	18.30
Exercised	(1,070,002)	(12,500)	13.26
Revoked or expired	(123,200)	-	15.44
December 31, 1996	4,469,050	2,280	15.49
Granted	1,567,112	-	23.60
Exercised	(589,930)	-	13.72
Revoked or expired	(235,202)	-	16.26
December 31, 1997	5,211,030	2,280	18.12
Granted	2,080,349	-	32.72
Exercised	(466,812)	-	16.15
Revoked or expired	(222,230)	-	23.84
December 31, 1998	6,602,337	2,280	$ 22.64

</TABLE>

In accordance with the provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("FAS 123"), the Company applies APB Opinion 25 in accounting for its stock option plans and, accordingly, does not recognize compensation cost for options granted to executives and other key employees. If the Company had elected to recognize compensation cost based on the fair value of the options granted at grant date as prescribed by FAS 123, earnings from continuing operations before extraordinary items, net earnings and earnings per share would have been reduced to the pro forma amounts shown in the table below (in millions except per share amounts):

<TABLE>
<CAPTION>

	Year Ended December 31,		
	1998	1997	1996
<S>	<C>	<C>	<C>
Earnings from continuing operations before extraordinary items	$ 473.8	$ 394.4	$ 505.8
Net earnings	435.3	297.2	400.4
Basic earnings per share			
From continuing operations before extraordinary items	$ 2.20	$ 1.78	$ 2.32
Discontinued operations	(.18)	(.03)	(.04)

	1998	1997	1996
Extraordinary items	-	(.43)	(.46)
Net basic earnings per share	$ 2.02	$ 1.32	$ 1.82
Diluted earnings per share			
From continuing operations before extraordinary items	$ 2.17	$ 1.75	$ 2.29
Discontinued operations	(.18)	(.03)	(.04)
Extraordinary items	-	(.42)	(.46)
Net diluted earnings per share	$ 1.99	$ 1.30	$ 1.79

The effects of applying FAS 123 in this pro forma disclosure are not indicative of future amounts.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for grants in 1998, 1997 and 1996:

	1998	1997	1996
Risk free interest rate	5.57%	6.90%	6.25%
Expected life (years)	8	8	8
Expected dividend yield	.611%	.85%	1.40%
Expected volatility	.2241	.2205	.1925
Weighted average fair value of options granted (per share)	$ 12.77	$ 9.75	$ 6.16

Stock options available for future grants amounted to 6,856,789; 493,642; and 1,813,542 at December 31, 1998, 1997 and 1996, respectively. Exercisable stock options amounted to 1,706,453; 1,353,198; and 1,496,708 at December 31, 1998, 1997 and 1996, respectively.

The following table summarizes information about stock options outstanding and exercisable at December 31, 1998:

Exercise Price Range	Outstanding Shares	Outstanding Average Life (*)	Outstanding Average Exercise Price	Exercisable Shares	Exercisable Average Exercise Price
$10.46 - $18.28	3,169,796	5.5	$ 15.84	1,518,416	$ 15.06
20.28 - 29.82	1,436,972	8.1	23.60	188,037	23.66
30.74 - 35.28	1,997,849	9.2	32.75	-	-
	6,604,617			1,706,453	

* Average life remaining in years.

Note 9. Segment and Geographic Reporting

The Company operates principally in the following lines of business: natural gas; refining, marketing and chemicals; exploration and production; coal; and power. Separate management of each segment is required because each line of business is subject to different production, marketing and technology strategies.

Natural gas operations involve the production, purchase, gathering, storage, transportation, marketing and sale of natural gas, principally to utilities, industrial customers and other pipelines, and include the operation of natural gas liquids extraction plants. Sales are primarily made to pipeline and distribution companies in most major areas of the United States.

Refining, marketing and chemicals operations involve the purchase, transportation and sale of refined products, crude oil, condensate and natural gas liquids; the operation of refineries and chemical plants; the sale at retail of gasoline, petroleum products and convenience items; petroleum product terminaling and marketing of crude oil and refined petroleum products. Products from this segment are sold to customers worldwide.

Exploration and production operations involve the exploration, development and production of natural gas, crude oil, condensate and natural gas liquids. Sales are made to affiliated companies, industrial users, interstate pipelines and distribution companies in the Rocky Mountain, central and southwest areas of the United States and offshore Gulf of Mexico.

Coal operations include the mining, processing and marketing of coal from Company-owned reserves and from other sources, and the brokering of coal for others. Sales are made to utilities and industrial customers in the United States and to export markets in Canada.

Power operations involve the ownership of, participation in and operation of power projects in the United States and internationally. Power is sold to customers in the Northeast United States and internationally in Asia and Latin America.

Corporate and other operations include real estate activities and corporate income and expense not allocated to the operating segments.

The Company's operating revenues from external customers; intersegment revenues; earnings (loss) before interest and income taxes; depreciation, depletion and amortization; equity income (loss) from investments; and capital expenditures for the years ended December 31, 1998, 1997 and 1996 are shown as follows (Millions of Dollars):

<TABLE>
<CAPTION>

<S>	1998 <C>	1997 <C>	1996 <C>
Operating Revenues From External Customers			
Natural gas	$ 1,356.8	$ 2,125.5	$ 3,793.4
Refining, marketing and chemicals	5,200.4	6,870.9	7,360.9
Exploration and production	436.6	383.4	184.7
Coal	241.7	226.8	713.6
Power	121.1	103.8	92.6
Corporate and other	11.6	19.7	21.7
Consolidated totals	$ 7,368.2	$ 9,730.1	$ 12,166.9
Intersegment Revenues			
Natural gas	$ 1.6	$ 40.7	$ 196.1
Refining, marketing and chemicals	2.3	6.2	3.9
Exploration and production	26.4	106.8	213.8
Coal	-	-	-
Power	-	-	-
Corporate and other	11.4	9.7	11.0
Consolidated totals	$ 41.7	$ 163.4	$ 424.8

Earnings (Loss) Before Interest and Income Taxes

	1998	1997	1996
Natural gas	$ 594.3	$ 583.0	$ 490.8
Refining, marketing and chemicals	243.9	95.6	94.4
Exploration and production	109.8	167.6	135.1
Coal	17.4	25.3	356.0
Power	67.8	43.4	41.4
Corporate and other	(88.7)	(70.4)	(74.1)
Consolidated totals	$ 944.5	$ 844.5	$ 1,043.6
Depreciation, Depletion and Amortization (Excluding Amortization of Goodwill)			
Natural gas	$ 118.3	$ 136.5	$ 161.7
Refining, marketing and chemicals	78.3	74.6	73.3
Exploration and production	209.2	185.5	158.2
Coal	14.6	14.1	37.3
Power	3.2	3.1	2.4
Corporate and other	7.0	4.1	6.0
Consolidated totals	$ 430.6	$ 417.9	$ 438.9

</TABLE>

<TABLE>
<CAPTION>

<S>	1998 <C>	1997 <C>	1996 <C>
Equity Income (Loss) from Investments			
Natural gas	$ 80.4	$ 92.6	$ 93.0
Refining, marketing and chemicals	1.0	8.7	1.1
Exploration and production	-	-	-
Coal	-	-	-
Power	43.0	36.2	24.1
Corporate and other	(0.1)	-	(0.1)
Consolidated totals	$ 124.3	$ 137.5	$ 118.1
Capital Expenditures			
Natural gas	$ 192.2	$ 224.7	$ 212.5
Refining, marketing and chemicals	229.1	167.6	215.3
Exploration and production	934.8	574.4	375.2
Coal	34.7	18.8	51.5
Power	2.0	2.2	3.7
Corporate and other	11.2	9.0	22.6
Consolidated totals	$ 1,404.0	$ 996.7	$ 880.8

</TABLE>

The Company's assets and amount of investment in equity method investees by segment as of December 31, 1998, 1997 and 1996 is as follows (Millions of Dollars):

<TABLE>
<CAPTION>

<S>	1998 <C>	1997 <C>	1996 <C>
Assets			
Natural gas	$ 5,379.5	$ 5,262.0	$ 5,448.2
Refining, marketing and chemicals	3,351.2	3,795.4	4,061.6
Exploration and production	2,161.6	1,484.0	1,125.3
Coal	269.6	252.7	225.3
Power	449.8	258.1	211.1
Corporate and other	692.4	587.5	548.9
Consolidated totals	$ 12,304.1	$ 11,639.7	$ 11,620.4

Equity Method Investments			
Natural gas	$ 608.9	$ 521.7	$ 404.0
Refining, marketing and chemicals	68.2	64.6	69.1
Exploration and production	-	-	-
Coal	.5	.5	.5
Power	295.0	167.5	133.2
Corporate and other	(1.8)	(1.7)	(1.9)
Consolidated totals	$ 970.8	$ 752.6	$ 604.9

</TABLE>

Intersegment sales are accounted for on the basis of contract, current market or internally established transfer prices.

The Coal revenues and earnings before interest and income taxes for 1996 include a gain before income taxes of $272.3 million from the sale of the Utah coal mining operations. See Note 10 of the Notes to the Consolidated Financial Statements.

In September 1996, Coastal and Westcoast Energy Inc. ("Westcoast") jointly announced plans to form one of North America's largest marketers of natural gas and electricity through the combination of the operations of the two companies' related marketing and service subsidiaries. Agreements were concluded in February 1997, which created Engage in which Coastal and Westcoast indirectly own 50% each. Natural gas operating revenues for the first two months of 1997 and the year ended December 31, 1996 include the revenues of Coastal's natural gas marketing operations ($833.5 million and $2,780.5 million, respectively). Subsequent to the combination, Engage's revenues are not included in Coastal's

operating revenues; however, Coastal's share of Engage's net earnings is included in Other income-net. As part of the combination, Coastal received an equalization payment of $42 million which is included in the Natural Gas earnings before interest and income taxes in 1997.

In June 1998, the power purchase agreement associated with the Company's Fulton Power Plant ("Plant") was restructured. In connection with the restructuring, a net gain of $17.2 million was recorded in the Power segment. The net gain reflects a $23 million reduction in the Plant's carrying value (to estimated fair value following the restructuring) and deferral of certain proceeds to cover estimated future costs.

In October 1998, the Company sold certain non-core natural gas processing and gathering assets. Revenues and earnings before interest and income taxes for the Natural Gas segment include a gain of $58.6 million from the sale.

Refining, marketing and chemicals revenues include gross profit arising from the selling, trading and exchanging of third party products. Approximate amounts from these transactions included in revenues and the impact on earnings, exclusive of interest costs, were (Millions of Dollars):

<TABLE>
<CAPTION>

<S>	1998 <C>	1997 <C>	1996 <C>
Revenues	$ 34.8	$ 26.3	$ 26.1
Impact on earnings	22.6	17.1	16.9

</TABLE>

The number and magnitude of such transactions may vary significantly from year to year, particularly in view of conditions in world petroleum markets.

The Company's operating revenues for the years ended December 31, 1998, 1997 and 1996 and property, plant and equipment as of December 31, 1998, 1997 and 1996, by geographic area, are shown as follows (Millions of Dollars):

<TABLE>
<CAPTION>

	1998	1997	1996
Operating Revenues			
United States	$ 6,381.7	$ 8,059.6	$ 10,595.8
Foreign, Aruba	743.4	1,251.4	1,154.8
Foreign, Other	243.1	419.1	416.3
Consolidated totals	$ 7,368.2	$ 9,730.1	$ 12,166.9
Property, Plant and Equipment			
United States	$ 7,344.9	$ 6,551.0	$ 6,109.9
Foreign, Aruba	564.0	478.8	460.3
Foreign, Other	115.0	91.8	84.7
Consolidated totals	$ 8,023.9	$ 7,121.6	$ 6,654.9

Revenues from sales to any single customer during 1998, 1997 or 1996 did not amount to 10% or more of the Company's consolidated revenues. Revenues by geographic area are attributed to countries based on the location of Company subsidiaries making the sales.

Note 10. Sale of Utah Coal Mining Operations

On December 20, 1996, the Company completed the sale of its coal mining operations in Utah for approximately $610.1 million in cash. The Company retained its coal properties in the eastern United States and is continuing to operate them. The sale resulted in a gain before income taxes of $272.3 million, which is included in the operating revenues of the Coal segment. The net earnings from the sale was a gain of $177.0 million, $.84 per share-basic or $.83 per share-diluted.

Following is a summary of the results of operations of the Utah coal mining operations (Millions of Dollars):

	For the Period From January 1, 1996 Through December 20, 1996
Operating revenues	$ 200.7
Costs and expenses	145.0
Earnings before income taxes	55.7
Income taxes	16.6
Net earnings	$ 39.1

Note 11. Benefit Plans

The Company has non-contributory pension plans covering substantially all U.S. employees. These plans provide benefits based on final average monthly compensation and years of service. The Company's funding policy is to contribute the amount necessary for the plan to maintain its qualified status under the Employment Retirement Income Security Act of 1974, as amended. The following tables provide a reconciliation of the changes in the pension plans' benefit obligations and fair value of assets over each of the years ended December 31, 1998 and 1997 and a statement of the funded status as of December 31, 1998 and 1997 (Millions of Dollars):

<TABLE>
<CAPTION>

	Year Ended December 31, 1998	1997
Change in Benefit Obligation		
Benefit obligation at beginning of year	$ 729.3	$ 658.2
Service cost	19.6	17.2
Interest cost	49.0	47.5
Plan amendment	3.8	-
Actuarial (gain) loss	(1.5)	(5.8)
Change in discount rate	-	55.0
Benefit payments	(42.3)	(42.8)
Benefit obligation at end of year	$ 757.9	$ 729.3
Change in Plan Assets		
Fair value of plan assets at beginning of year	$ 1,298.7	$ 1,078.7
Actual return on plan assets	224.9	262.5
Employer contributions	.5	.3
Benefit payments	(42.3)	(42.8)
Fair value of plan assets at end of year	$ 1,481.8	$ 1,298.7

	December 31, 1998	1997
Funded Status		
Funded status at year end	$ 723.9	$ 569.4
Unrecognized transition obligation (asset)	(28.5)	(37.1)
Unrecognized prior service cost	5.9	3.0
Unrecognized net (gain) loss	(293.1)	(200.7)
Prepaid pension cost	$ 408.2	$ 334.6

Plan assets include common stock and Class A common stock of the Company amounting to a total of 7.2 million shares and 7.5 million shares at December 31, 1998 and 1997, respectively.

The following table provides the components of the net periodic pension benefit for 1998, 1997 and 1996 (Millions of Dollars):

	Year Ended December 31, 1998	1997	1996
Service cost	$ 19.6	$ 17.2	$ 18.3
Interest cost	49.0	47.5	45.6
Expected return on assets	(126.4)	(105.7)	(92.0)
Amortization of transition obligation (asset)	(8.6)	(8.6)	(8.6)
Amortization of prior service cost	.8	.4	.4
Amortization of net (gain) loss	(7.6)	(3.1)	(1.3)
Deferred regulatory amounts	-	-	16.0
Net periodic pension benefit	$ (73.2)	$ (52.3)	$ (21.6)

</TABLE>

The discount rate used in determining the actuarial present value of the projected benefit obligation was 7.00% in 1998 and 1997 and 7.50% in 1996. The expected increase in future compensation levels was 4% in 1998, 1997 and 1996 and the expected long-term rate of return on assets was 10% in 1998, 1997 and 1996.

The Company also participates in several multi-employer pension plans for the benefit of its employees who are union members. Company contributions to these plans were not material for 1998, 1997 or 1996.

The Company also makes contributions to a thrift plan, which is a trusteed, voluntary and contributory plan for eligible employees of the Company. The Company's contributions, which are based on matching employee contributions, amounted to $19.4 million, $18.9 million and $18.5 million in 1998, 1997 and 1996, respectively.

The Company provides certain health care and life insurance benefits for retired employees. Substantially all U.S. employees are provided these benefits. The estimated costs of retiree benefit payments are accrued during the years the employee provides services. Certain costs have been deferred by the rate regulated subsidiaries and were amortized through October 31, 1996. Effective November 1, 1996, these costs are no longer being deferred as a result of the Company's discontinued application of FAS 71.

The following tables provide a reconciliation of the changes in the postretirement benefit obligation and the fair value of plan assets over each of the years ended December 31, 1998 and 1997, and a statement of the funded status as of December 31, 1998 and 1997 (Millions of Dollars):

<TABLE>
<CAPTION>

	Year Ended December 31, 1998	Year Ended December 31, 1997
<S>	<C>	<C>
Change in Benefit Obligation		
Benefit obligation at beginning of year	$ 108.0	$ 110.5
Service cost	2.3	2.3
Interest cost	6.9	7.0
Participant contributions	2.8	3.0
Actuarial (gain) loss	(.8)	(1.2)
Benefit payments	(10.2)	(10.2)
Curtailment (gain) loss	(.9)	-
Plan amendment	-	(3.4)
Benefit obligation at end of year	$ 108.1	$ 108.0
Change in Plan Assets		
Fair value of plan assets at beginning of year	$ 24.1	$ 26.0
Actual return on plan assets	.1	1.4
Employer contributions	5.5	1.3
Administrative expenses	(.1)	(.2)
Benefit payments	(5.2)	(4.4)
Fair value of plan assets at end of year	$ 24.4	$ 24.1

</TABLE>

<TABLE>
<CAPTION>

	December 31, 1998	December 31, 1997

<S> <C> <C>

Funded Status		
Funded status at year end	$ (83.7)	$ (83.9)
Unrecognized transition obligation	83.2	89.7
Unrecognized prior service cost	3.5	3.9
Unrecognized (gain) loss	(34.1)	(36.3)
Accrued postretirement benefit obligation	$ (31.1)	$ (26.6)

</TABLE>

The following table provides the components of net periodic postretirement benefit cost for 1998, 1997 and 1996 (Millions of Dollars):

<TABLE>
<CAPTION>

	Year Ended December 31,		
	1998	1997	1996
Service cost	$ 2.3	$ 2.3	$ 2.5
Interest cost	6.9	7.0	7.6
Expected return on assets	(.7)	(.8)	(.7)
Amortization of transition obligation	6.0	6.0	6.2
Amortization of prior service cost	.4	.4	.5
Amortization of net (gain) loss	(2.6)	(2.6)	(1.9)
Deferred regulatory amounts	-	3.5	3.6
Net periodic postretirement benefit cost	$ 12.3	$ 15.8	$ 17.8

</TABLE>

The assumed health care cost trend rate used in measuring the accumulated postretirement benefit obligation was 9.0% in 1998, declining gradually to 6.0% by the year 2004. The assumed health care cost trend rate used in measuring

the accumulated postretirement benefit obligation was 9.7% in 1997 and 10.4% in 1996. A one percentage point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 1998 by approximately 4.65% and the net postretirement health care cost by approximately 4.42%. A one percentage point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 1998 by approximately 4.64% and the net postretirement health care cost by approximately 4.52%. The assumed discount rate used in determining the accumulated postretirement benefit obligation was 7.0% in 1998, 7.25% in 1997 and 7.5% in 1996 and the expected long-term rate of return on assets was 4.3% in 1998, 1997 and 1996.

Note 12. Taxes on Income

Pretax earnings from continuing operations before extraordinary items are composed of the following (Millions of Dollars):

<TABLE>
<CAPTION>

	Year Ended December 31,		
	1998	1997	1996
United States	$ 502.8	$ 458.2	$ 591.9
Foreign	146.8	78.8	83.4
	$ 649.6	$ 537.0	$ 675.3

</TABLE>

Provisions for income taxes from continuing operations before extraordinary items are composed of the following (Millions of Dollars):

	Year Ended December 31,		
	1998	1997	1996
Current income taxes:			
Federal	$ 5.0	$ 50.7	$ 87.2
Foreign	5.5	5.3	6.4
State	4.5	8.4	13.7
	15.0	64.4	107.3
Deferred income taxes:			
Federal	140.9	69.5	56.4
Foreign	3.4	3.3	3.0
State	7.4	1.1	.6
	151.7	73.9	60.0
Taxes on Income	$ 166.7	$ 138.3	$ 167.3

The Company and the Internal Revenue Service ("IRS") Appeals Office have concluded a final settlement of certain adjustments originally proposed to federal income tax returns filed for the years 1985 through 1987. The IRS has proposed additional adjustments to those returns, and the Company is contesting certain of these adjustments before the IRS Appeals Office. The Company's federal income tax returns filed for the years 1988 through 1990 have been examined by the IRS and the Company has received notice of proposed adjustments to the returns for each of those years. The Company currently is contesting certain of these adjustments with the IRS Appeals Office. Examination of the Company's federal income tax returns for 1991, 1992, 1993 and 1994 began in 1997. It is the opinion of management that adequate provisions for federal income taxes have been reflected in the consolidated financial statements.

Provisions for income taxes were different than the amount computed by applying the statutory U.S. federal income tax rate to earnings before tax. The reasons for these differences are (Millions of Dollars):

	Year Ended December 31,		
	1998	1997	1996
Tax expense by applying the U.S. federal income tax rate of 35%	$ 227.4	$ 187.9	$ 236.3
Increases (reductions) in taxes resulting from:			
Tight sands gas credit	(7.9)	(6.5)	(7.3)
State income tax cost	7.7	6.2	9.2
Goodwill	6.4	6.4	6.4
Research activities credit	-	-	(11.8)
Exclusion for foreign investments and certain domestic joint ventures	(50.3)	(50.6)	(59.2)
Depletion and depreciation	(1.2)	(1.4)	(6.3)
Other	(15.4)	(3.7)	-
Taxes on income	$ 166.7	$ 138.3	$ 167.3

Deferred tax liabilities (assets) which are recognized for the estimated future tax effects attributable to temporary differences and carryforwards are (Millions of Dollars):

	December 31, 1998	December 31, 1997
Excess of book basis over tax basis of property, plant and equipment	$ 1,637.4	$ 1,469.6
Pensions and benefit costs..	109.8	98.6
Purchase gas and other recoverable cost...................................	-	32.7
Other...	67.2	20.2
Deferred tax liabilities..	1,814.4	1,621.1
Alternative minimum tax credit carryforward...............................	(195.4)	(181.2)
Purchase gas and other recoverable cost...................................	(14.0)	-
Deferred tax assets...	(209.4)	(181.2)
Deferred income taxes...	$ 1,605.0	$ 1,439.9

U.S. income taxes have been provided for earnings of foreign subsidiaries that are expected to be distributed to the U.S. parent company. Foreign subsidiaries' cumulative unremitted earnings of $323.2 million are considered to be indefinitely reinvested outside the U.S. and, accordingly, no U.S. income taxes have been provided on those earnings.

Note 13. Discontinued Operations

The Company is pursuing the disposition of its 50% ownership of ANR Advance Transportation Company, Inc. ("ANR Advance"), a trucking operation. The Company is considering all options, including full liquidation, in cooperation with other owners. Accordingly, the trucking operations are being reported as a discontinued operation.

The net assets (liabilities) being disposed of have been classified in the accompanying consolidated balance sheet in Other Assets at December 31, 1998. Prior year financial statements have been restated to conform with the current presentation. The net assets (liabilities) of the discontinued operations amounted to $(.5) million and $47.3 million at December 31, 1998 and 1997, respectively.

Operating results of the discontinued operations are shown separately in the accompanying statement of consolidated operations. Prior year financial statements have been restated to conform with the current presentation. The loss from operations shown on the statement of consolidated operations is net of income tax benefits of $1.9 million, $3.5 million and $4.2 million in 1998, 1997 and 1996, respectively. The estimated loss on disposal of the discontinued operations of $35.0 million is net of income tax benefits of $18.8 million.

Note 14. Extraordinary Items

Early Extinguishment of Debt. In February 1997, the Company purchased and retired $798.0 million of notes and debentures with interest rates ranging from 9 3/4% to 10 3/4%. None of the issues were eligible for redemption and the purchase included payment of a premium. The Company incurred an after-tax extraordinary charge of $90.6 million ($.43 per share-basic or $.42 per share-diluted), net of income taxes of $48.7 million, in connection with the repurchase of these debt securities.

In June 1996, the Company retired $400.0 million of 11 3/4% Senior Debentures due in 2006. Payment of the redemption premium and the recognition of deferred costs related to the Senior Debentures resulted in an extraordinary loss of $12.0 million ($.06 per share), net of related income taxes of $6.5

million.

Discontinuation of Regulatory Accounting. Effective November 1, 1996, the interstate natural gas pipeline and certain storage subsidiaries of the Company ceased to apply the provisions of FAS 71 to their transactions and balances. The Company believes this accounting change results in financial reporting which better reflects the results of operations in the economic environment in which these subsidiaries now operate. The impact of this change was a charge to earnings of $85.6 million ($.40 per share), net of related income taxes of $50.0 million.

Note 15. Earnings Per Share

Earnings per share are calculated following Statement of Financial Accounting Standards No. 128. The following data shows the amounts used in computing basic earnings per share and the effects on income and the weighted average number of shares of dilutive securities.

	For the Year Ended December 31, 1998		
	Income (Numerator) (Millions)	Shares (Denominator) (Thousands)	Per-Share Amount
Earnings from continuing operations before extraordinary items	$ 482.9		
Less preferred stock dividends	6.0		
Basic earnings per share			
Income available to common stockholders	476.9	212,543	$ 2.24
Effect of dilutive securities			
Options	-	2,248	
Convertible preferred stock	.3	1,317	
Diluted earnings per share			
Income available to common stockholders plus assumed conversions	$ 477.2	216,108	$ 2.21

	For the Year Ended December 31, 1997		
	Income (Numerator) (Millions)	Shares (Denominator) (Thousands)	Per-Share Amount
Earnings from continuing operations before extraordinary items	$ 398.7		
Less preferred stock dividends	17.4		
Basic earnings per share			
Income available to common stockholders	381.3	211,892	$ 1.80
Effect of dilutive securities			
Options	-	1,798	
Convertible preferred stock	.4	1,412	
Diluted earnings per share			
Income available to common stockholders plus assumed conversions	$ 381.7	215,102	$ 1.77

<TABLE>
<CAPTION>

	For the Year Ended December 31, 1996		
	Income (Numerator) (Millions)	Shares (Denominator) (Thousands)	Per-Share Amount
<S>	<C>	<C>	<C>
Earnings from continuing operations before extraordinary items..................................	$ 508.0		
Less preferred stock dividends..........................	17.4		
Basic earnings per share			
Income available to common stockholders.............	490.6	210,987	$ 2.33
Effect of dilutive securities			
Options..	-	1,241	
Convertible preferred stock.........................	.4	1,458	
Diluted earnings per share			
Income available to common stockholders plus assumed conversions.............................	$ 491.0	213,686	$ 2.30

</TABLE>

Note 16. Litigation, Environmental and Regulatory Matters

Litigation. In connection with the December 20, 1996 sale of the Company's western coal operations, the Company assumed control of a pending dispute with the Intermountain Power Agency ("IPA") involving two coal sales agreements of Coastal States Energy Company, which contracts were included in the sale, and for which the Company continued to have certain responsibilities. On July 14, 1997, IPA made a demand for arbitration between the parties, asserting a claim of a gross inequity under the contracts requiring a reduction in the purchase price of coal sold before and after the sale of these coal operations. The Company believed that no gross inequity had occurred and that it would prevail in the arbitration on the merits. However, in an attempt to resolve this and several other unrelated issues concerning the Company's continuing responsibilities under the terms of the December 1996 sale, the Company entered into negotiation with several interested parties. Pursuant to a January 20, 1999 multi-party agreement, in which virtually all of the Company's indemnification obligations were terminated, IPA dismissed its "gross inequity" claim. This favorable resolution of all outstanding claims arising under the original sale of the western coal operations had no adverse impact on the Company.

In December 1992, certain of CIG's natural gas lessors in the West Panhandle Field filed a complaint in the U.S. District Court for the Northern District of Texas, claiming underpayment of royalties, breach of fiduciary duty, fraud and negligent misrepresentation. Management believes that CIG has numerous defenses to the lessors' claims, including (i) that the royalties were properly paid, (ii) that the majority of the claims were released by written agreement and (iii) that the majority of the claims are barred by the statute of limitations. In March of 1995, the trial court granted a partial

summary judgment in favor of CIG, holding that the four-year statute of limitations had not been tolled, that the releases are valid, and dismissing all tort claims and claims for breach of any duty of disclosure. The remaining claim for underpayment of royalties was tried to a jury which, in May 1995, made findings favorable to CIG. On June 7, 1995, the trial court entered a judgment that the lessors recover no monetary damages from CIG and permanently estopping the lessors from asserting any claim based on an interpretation of the contract different than that asserted by CIG in the litigation. The lessors' motion for a new trial was denied on July 18, 1997, and both parties filed appeals. On June 7, 1996, the same plaintiffs sued CIG in state court in Amarillo, Texas for underpayment of royalties. CIG removed the second lawsuit to federal court which granted a stay of the second suit pending the outcome of the first lawsuit. Oral arguments were heard before the Fifth Circuit Court of Appeals on December 4, 1998, and the parties are awaiting the Court's decision.

In October 1996, the Company, along with several subsidiaries, was named as a defendant in a suit filed by several former and current African American employees in the United States District Court, Southern District of Texas. The suit alleges racially discriminatory employment policies and practices. Coastal vigorously denies these allegations and has filed responsive pleadings. Plaintiffs' counsel are seeking to have the suit certified as a class action of all former and current African American employees and initially claimed compensatory and punitive damages of $400 million. In February 1999, in response to Coastal's motion to deny class certification, plaintiffs' counsel obtained permission from the Court to delete all claims for compensatory and punitive damages and to seek equitable relief only. In January 1998, the plaintiffs amended their suit to exclude ANR Pipeline employees from the potential class. A new suit was then filed in state court in Wayne County, Michigan, seeking to have the Michigan suit certified as a class action of African American employees of ANR Pipeline and seeking unspecified damages as well as attorneys and expert fees. ANR Pipeline has filed responsive pleadings denying these allegations.

In 1996, Jack Grynberg filed a claim under the False Claims Act on behalf of the U.S. government in the U.S. District Court, District of Columbia, against 70 defendants, including ANR Pipeline and CIG. The suit sought damages for the alleged underpayment of royalties due to the purported improper measurement of gas. The 1996 suit was dismissed without prejudice in March 1997 and the dismissal was affirmed by the D.C. Court of Appeals in October 1998. In September 1997, Mr. Grynberg filed 77 separate, similar False Claims Act suits against natural gas transmission companies and producers, gatherers, and processors of natural gas, seeking unspecified damages. Coastal and several of its subsidiaries have been included in two of the September 1997 suits. The suits were filed in both the U.S. District Court, District of Colorado and the U.S. District Court, Eastern District of Michigan. The United States Department of Justice has notified the Company that it is reviewing these lawsuits to determine whether or not the United States will intervene.

Numerous other lawsuits and other proceedings which have arisen in the ordinary course of business are pending or threatened against the Company or its subsidiaries.

Although no assurances can be given and no determination can be made at this time as to the outcome of any particular lawsuit or proceeding, the Company believes there are meritorious defenses to substantially all such claims and that any liability which may finally be determined should not have a material adverse effect on the Company's consolidated financial position or results of operations.

Environmental Matters. The Company's operations are subject to extensive and evolving federal, state and local environmental laws and regulations. Compliance with such laws and regulations can be costly. Additionally, governmental authorities may enforce the laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties and remediation requirements.

The Company spent approximately $13 million in 1998 on environmental capital projects and anticipates capital expenditures of approximately $44 million in 1999 in order to comply with such laws and regulations. The majority of the 1999 expenditures is attributable to projects at the Company's refining, chemical and terminal facilities. The Company currently anticipates capital expenditures for environmental compliance for the years 2000 through 2002 of $20 to $40 million per year.

The Comprehensive Environmental Response, Compensation and Liability Act, also known as "Superfund," imposes liability for the release of a "hazardous substance" into the environment. Superfund liability is imposed without

regard to fault and even if the waste disposal was in compliance with the then current laws and regulations. With the joint and several liability imposed under Superfund, a potentially responsible party ("PRP") may be required to pay more than its proportional share of such costs. Certain subsidiaries of the Company and a company in which Coastal owns a 50% interest have been named as a PRP in several "Superfund" waste disposal sites. At the 11 sites for which there is sufficient information, total cleanup costs are estimated to be approximately $620 million, and the Company estimates its pro-rata exposure, to be paid over a period of several years, is approximately $7.5 million and has made appropriate provisions. At nine other sites, the Environmental Protection Agency ("EPA") is currently unable to provide the Company with an estimate of total cleanup costs and, accordingly, the Company is unable to calculate its share of those costs. Additionally, certain subsidiaries of the Company have been named as PRPs in two state sites. At one site, the North Carolina Department of Health, Environmental and Natural Resources has estimated the total cleanup costs to be approximately $50 million, but the Company believes the subsidiary's activities at this site were de minimis. At the second state site, the Florida Department of Environmental Protection has demanded reimbursement of its costs, which total $100,000, and suitable remediation. There is not sufficient information to estimate the remedial costs or the Company's pro-rata exposure at this site.

Future information and developments, including legislative and enforcement developments, will require the Company to continually reassess the expected impact of these environmental matters. However, the Company has evaluated its total environmental exposure based on currently available data, including its potential joint and several liability, and believes that compliance with all applicable laws and regulations will not have a material adverse impact on the Company's financial position or results of operations.

Regulatory Matters. On January 31, 1996, the FERC issued a "Statement of Policy and Request for Comments" ("Policy"). Under this Policy, (i) a pipeline and a customer are allowed to negotiate a contract which provides for rates and charges that exceed the pipeline's posted maximum tariff rates, provided that the customer agreeing to such negotiated rates has the ability to elect to receive service at the pipeline's posted maximum rate (known as a "recourse rate"), and (ii) a pipeline must also make subsequent tariff filings each time the pipeline negotiates a rate for service which is outside of the minimum and maximum range for the pipeline's cost-based recourse rates. To implement this Policy, a pipeline must make an initial tariff filing with the FERC to indicate that it intends to contract for services under this Policy. CIG has received FERC authority to enter into negotiated rate transactions. Separately, the FERC has determined that pipelines who seek to include negotiated rate transactions in the discount adjustment used to calculate their rates must file tariff sheets demonstrating that existing customers who purchase service under the pipeline's cost-of-service rates will not be harmed by negotiated rate discounts.

On July 29, 1998, the FERC issued a "Notice of Proposed Rulemaking," in which the FERC has proposed a number of further significant changes to the industry, including, among other things, removal of price caps in the short-term market (less than one year), capacity auctions, changed reporting obligations, the ability to negotiate terms and conditions of all services, elimination of the requirement of a matching term cap on the renewal of existing contracts, and a review of its policies for approving capacity construction. On the same day, the FERC also issued a "Notice of Inquiry" soliciting industry input on various matters affecting the pricing of long-term service and certificate pricing in light of changing market conditions. The due date for comments on both of these matters has been rescheduled twice and is currently scheduled for April 22, 1999. The FERC has indicated that it may consider both proposals together inasmuch as they raise several common issues.

On May 30, 1997, Wyoming Interstate Company, Ltd. ("WIC") filed with the FERC to increase its rates by approximately $5.7 million annually. On June 27, 1997, the FERC accepted the filing effective as of December 1, 1997, subject to refund. After the filing of testimony by WIC and other parties on July 2, 1998, WIC filed a settlement offer which, if approved, would have resolved all of the issues in the case. The settlement, however, was remanded to the Administrative Law Judge ("ALJ") because of opposition to the settlement by certain parties. In response to the remand, WIC and the parties have resubmitted a settlement offer which contains the same substantive provisions, but provides for the FERC to approve the settlement for some, if not all, parties, with the "severed" parties being able to litigate their issues in the case. The ALJ has certified the new settlement to the FERC, and dates for filing briefs on the new settlement have been established.

Certain other regulatory issues remain unresolved among CIG, ANR Pipeline, ANR Storage Company and WIC, their customers, their suppliers and the FERC. The Company has made provisions which represent management's assessment of the ultimate resolution of these issues. As a result, the Company anticipates that these regulatory matters will not have a material adverse effect on its consolidated financial position or results of operations. While the Company estimates the provisions to be adequate to cover potential adverse rulings on these and other issues, it cannot estimate when each of these issues will be resolved.

Note 17. Quarterly Results of Operations (Unaudited)

Results of operations by quarter for the years ended December 31, 1998 and 1997 were (Millions of Dollars Except per Share):

<TABLE>
<CAPTION>

	Quarter Ended			
	March 31, 1998	June 30, 1998	Sept. 30, 1998	Dec. 31, 1998*
<S>	<C>	<C>	<C>	<C>
Operating revenues.........................	$ 1,956.5	$ 1,924.4	$ 1,661.6	$ 1,825.7
Less purchases.............................	1,186.4	1,176.8	966.9	1,046.7
	770.1	747.6	694.7	779.0
Other income and expenses..................	645.3	656.1	602.9	604.2
Earnings from continuing operations........	124.8	91.5	91.8	174.8
Discontinued operations....................	(1.9)	3.1	(2.3)	(37.4)
Net earnings...............................	$ 122.9	$ 94.6	$ 89.5	$ 137.4
Basic earnings per share:				
From continuing operations.............	$ .57	$ .42	$ .43	$ .82
Discontinued operations.................	(.01)	.02	(.01)	(.18)
Net basic earnings per share...........	$ .56	$ .44	$ .42	$ .64
Diluted earnings per share:				
From continuing operations.............	$ .56	$ .42	$ .42	$ .81
Discontinued operations.................	(.01)	.01	(.01)	(.17)
Net diluted earnings per share	$ .55	$ .43	$ .41	$ .64

<FN>
*Includes a $58.6 million gain ($38.1 million net of income taxes, or $.18 per share) from the sale of certain non-core natural gas processing and gathering assets.
</FN>
</TABLE>

<TABLE>
<CAPTION>

	Quarter Ended			
	March 31, 1997	June 30, 1997	Sept. 30, 1997	Dec. 31, 1997
<S>	<C>	<C>	<C>	<C>
Operating revenues.........................	$ 3,205.8	$ 2,156.6	$ 2,143.0	$ 2,224.7
Less purchases.............................	2,465.4	1,473.2	1,427.9	1,497.0
	740.4	683.4	715.1	727.7
Other income and expenses..................	637.6	602.7	633.3	594.3
Earnings from continuing operations before extraordinary items.............	102.8	80.7	81.8	133.4
Discontinued operations....................	(1.6)	(1.4)	(1.4)	(2.2)
Earnings before extraordinary items........	101.2	79.3	80.4	131.2
Extraordinary items........................	(90.6)	-	-	-
Net earnings	$ 10.6	$ 79.3	$ 80.4	$ 131.2
Basic earnings per share:				
From continuing operations before extraordinary items...........	$ .47	$ .36	$ .36	$ .61
Discontinued operations.................	(.01)	(.01)	-	(.01)

Extraordinary items	(.43)	-	-	-
Net basic earnings per share	$ .03	$ .35	$ .36	$ .60
Diluted earnings per share:				
From continuing operations before extraordinary items	$ .46	$ .36	$ .35	$ .60
Discontinued operations	(.01)	(.01)	-	(.01)
Extraordinary items	(.42)	-	-	-
Net diluted earnings per share	$ .03	$ .35	$ .35	$ .59

</TABLE>

Operating revenues, purchases and operating expenses for 1997 include activity for only two months from Coastal's gas marketing operations, which became a part of Engage Energy US, L.P. and Engage Energy Canada, L.P. in February 1997, and are included in Other income-net on the equity method thereafter.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Reserves, capitalized costs, costs incurred in oil and gas acquisition, exploration and development activities, results of operations and the standardized measure of discounted future net cash flows are presented for the exploration and production segment. Natural gas systems reserves and the related standardized measure of discounted future net cash flows are separately presented for natural gas operations. All of the Company's producing properties are located in the United States.

Estimated Quantities of Proved Reserves

<TABLE>
<CAPTION>

	Natural Gas Systems	Exploration and Production		
	Developed	Developed	Undeveloped	Total
Natural Gas (MMcf):				
<S>	<C>	<C>	<C>	<C>
1998	211,761	1,287,207	1,028,167	2,527,135
1997	248,248	953,235	551,031	1,752,514
1996	267,927	757,117	431,488	1,456,532
Oil, Condensate and Natural Gas Liquids (000 barrels):				
1998	237	31,894	20,153	52,284
1997	349	27,016	12,778	40,143
1996	391	30,328	13,743	44,462

</TABLE>

Changes in proved reserves since the end of 1995 are shown in the following table.

<TABLE>
<CAPTION>

	Natural Gas (MMcf)		Oil, Condensate and Natural Gas Liquids (000 barrels)	
Total Proved Reserves	Natural Gas Systems	Exploration and Production	Natural Gas Systems	Exploration and Production

<S>

Total, end of 1995	302,420	851,064	126	36,164
Production during 1996	(39,405)	(129,149)	(23)	(5,062)
Extensions and discoveries	264	418,410	265	7,083
Acquisitions	-	56,729	-	5,239
Sales of reserves in-place	-	(30,412)	-	(1,076)
Revisions of previous quantity estimates and other	4,648	21,963	23	1,723
Total, end of 1996	267,927	1,188,605	391	44,071
Production during 1997	(38,135)	(159,127)	(57)	(4,957)
Extensions and discoveries	8,870	305,319	-	5,775
Acquisitions	-	252,219	-	2,340
Sales of reserves in-place	-	(56,894)	-	(6,739)
Revisions of previous quantity estimates and other	9,586	(25,856)	15	(696)
Total, end of 1997	248,248	1,504,266	349	39,794
Production during 1998	(39,058)	(185,732)	(44)	(5,578)
Extensions and discoveries	404	518,529	-	9,185
Acquisitions	-	575,934	-	11,915
Sales of reserves in-place	-	(25,556)	-	(1,072)
Revisions of previous quantity estimates and other	2,167	(72,067)	(68)	(2,197)
Total, end of 1998	211,761	2,315,374	237	52,047

</TABLE>

Total proved reserves for natural gas systems exclude storage gas and liquids volumes. The natural gas systems storage gas volumes are 225,853, 213,571 and 153,276 MMcf and storage liquids volumes are approximately 232,000, 209,000 and 192,000 barrels at December 31, 1998, 1997 and 1996, respectively. Total proved reserves for natural gas includes approximately 162,000, 32,000 and 90,000 MMcf associated with volumetric production payments sold by the Company for the years 1998, 1997 and 1996, respectively.

All of the Company's proved reserves are located in the United States. International activities are connected with the evaluation of various concessions. Therefore, the tables setting forth statistical data on reserves and cash flows are for properties located in the United States while the tables on costs contain certain capitalized transactions attributable to start-up activities connected with international operations. These capitalized international transactions are not material in nature.

Capitalized Costs Relating to Exploration and Production Activities
(Millions of Dollars)

<TABLE>
<CAPTION>

	December 31, 1998	December 31, 1997
Proved and Unproved Properties:		
Proved properties	$ 2,667	$ 2,006
Unproved properties	153	108
	2,820	2,114
Accumulated depreciation, depletion and amortization	(765)	(757)

	$ 2,055	$ 1,357

<FN>
The Company follows the full-cost method of accounting for oil and gas properties.
</FN>
</TABLE>

Costs Excluded from Amortization
(Millions of Dollars)

The following table summarizes the costs related to unevaluated properties and major development projects which are excluded from amounts subject to amortization at December 31, 1998. The Company regularly evaluates these costs to determine whether impairment has occurred. The majority of these costs are expected to be evaluated and included in the amortization base within three years.

<TABLE>
<CAPTION>

	Years Costs Incurred				
	Total	1998	1997	1996	Prior to 1996
<S>	<C>	<C>	<C>	<C>	<C>
Property acquisition............................	$ 159	$ 132	$ 23	$ 2	$ 2
Exploration.....................................	75	66	4	3	2
Development.....................................	39	32	6	1	-
Capitalized interest............................	7	7	-	-	-
	$ 280	$ 237	$ 33	$ 6	$ 4

</TABLE>

Costs Incurred in Oil and Gas Acquisition, Exploration and Development Activities (Millions of Dollars)

<TABLE>
<CAPTION>

	Year Ended December 31,		
	1998	1997	1996
<S>	<C>	<C>	<C>
Property acquisition costs:			
Proved..	$ 129	$ 48	$ 42
Unproved..	133	49	27
Exploration costs...	123	83	48
Development costs...	540	388	255

</TABLE>

Results of Operations for Domestic Exploration and Production Activities
(Millions of Dollars)

<TABLE>
<CAPTION>

	Year Ended December 31,		
	1998	1997	1996
<S>	<C>	<C>	<C>
Revenues:			
Sales...	$ 333	$ 227	$ 113
Transfers...	111	240	282

Total	444	467	395
Production costs	(89)	(92)	(73)
Operating expenses	(44)	(34)	(32)
Depreciation, depletion and amortization	(195)	(171)	(141)
	116	170	149
Income tax expense	(33)	(52)	(45)
Results of operations for producing activities (excluding corporate overhead and interest costs)	$ 83	$ 118	$ 104

</TABLE>

The average domestic amortization rate per equivalent Mcf was $0.89 in 1998, $0.91 in 1997 and $0.88 in 1996. Depreciation, depletion and amortization excludes provisions for the impairment of international projects of $9.1 million in 1998, $10.7 million in 1997 and $14.6 million in 1996.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities. Future cash inflows for the year ended December 31, 1998 from the sale of proved reserves and estimated production and development costs as calculated by the Company's engineers and reviewed by Huddleston, the Company's independent engineer, are discounted by 10% after they are reduced by the Company's estimate for future income taxes. The amounts for 1997 and 1996 were calculated by Huddleston. The calculations are based on year-end prices and costs, statutory tax rates and nonconventional fuel source tax credits that relate to existing proved oil and gas reserves in which the Company has mineral interests.

The standardized measure is not intended to represent the market value of reserves and, in view of the uncertainties involved in the reserve estimation process, including the instability of energy markets as evidenced by recent declines in both natural gas and crude oil prices, may be subject to material future revisions (Millions of Dollars):

<TABLE>
<CAPTION>

	Year Ended December 31,					
	1998		1997		1996	
	Natural Gas Systems	Exploration and Production	Natural Gas Systems	Exploration and Production	Natural Gas Systems	Exploration and Production
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Future cash inflows	$ 256	$ 4,939	$ 291	$ 4,190	$ 430	$ 5,384
Future production and development costs	(79)	(1,909)	(87)	(1,479)	(85)	(1,432)
Future income tax expenses	(57)	(584)	(67)	(635)	(117)	(1,141)
Future net cash flows	120	2,446	137	2,076	228	2,811
10% annual discount for estimated timing of cash flows	(51)	(865)	(57)	(651)	(88)	(851)
Standardized measure of discounted future net cash flows	$ 69	$ 1,581	$ 80	$ 1,425	$ 140	$ 1,960

</TABLE>

Future cash inflows include $187 million for 1998, $50 million for 1997 and $245 million for 1996 related to volumes dedicated to volumetric production payments sold by the Company.

Principal sources of change in the standardized measure of discounted future net cash flows during each year are (Millions of Dollars):

	Year Ended December 31,					
	1998		1997		1996	
	Natural Gas Systems	Exploration and Production	Natural Gas Systems	Exploration and Production	Natural Gas Systems	Exploration and Production
Sales and transfers, net of production costs............	$ (34)	$ (338)	$ (34)	$ (373)	$ (45)	$ (304)
Net changes in prices and production costs............	3	(334)	(53)	(906)	95	874
Extensions and discoveries...	-	430	10	322	4	941
Acquisitions.................	-	317	-	289	-	188
Sales of reserves in-place...	-	(21)	-	(117)	-	(27)
Development costs incurred during the period that reduced estimated future development costs...........	-	115	-	11	-	36
Revisions of previous quantity estimates, timing and other...................	6	(322)	(34)	(392)	39	26
Accretion of discount........	8	141	17	233	7	57
Net change in income taxes...	6	168	34	398	(35)	(550)
Net change...................	$ (11)	$ 156	$ (60)	$ (535)	$ 65	$ 1,241

None of the amounts include any value for natural gas systems storage gas and liquids volumes, which was approximately 41 Bcf for CIG, 132 Bcf for ANR Pipeline, 53 Bcf for Mid Michigan Gas Storage Company and 232,000 barrels of liquids for CIG at the end of 1998.

THE COASTAL CORPORATION AND SUBSIDIARIES
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF THE REGISTRANT

THE COASTAL CORPORATION
BALANCE SHEET
(Millions of Dollars)

	December 31,	
	1998	1997
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents..	$ 79.6	$ .5
Receivables..	6.1	8.9
Receivables from subsidiaries..	1,516.6	1,150.6
Prepaid expenses and other...	4.6	3.4
Total Current Assets..	1,606.9	1,163.4

PROPERTY, PLANT AND EQUIPMENT - at cost, net	.5	.9
INVESTMENTS IN SUBSIDIARIES AND OTHER ASSETS:		
Investment in subsidiaries at cost plus equity in undistributed earnings since acquisition	4,361.7	3,992.4
Due from subsidiaries	128.1	-
Deferred federal income taxes	120.5	86.4
Other assets	392.3	324.9
	5,002.6	4,403.7
	$ 6,610.0	$ 5,568.0

</TABLE>

See Notes to Condensed Financial Statements.

THE COASTAL CORPORATION AND SUBSIDIARIES
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF THE REGISTRANT

THE COASTAL CORPORATION
BALANCE SHEET
(Millions of Dollars)

<TABLE>
<CAPTION>

	December 31,	
	1998	1997
<S>	<C>	<C>
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Notes payable	$ 87.0	$ 114.0
Accounts payable and accrued expenses	70.0	124.4
Payable to subsidiaries	242.4	171.7
Current maturities on long-term debt	50.0	30.0
Total Current Liabilities	449.4	440.1
DUE TO SUBSIDIARIES	309.8	-
DEBT:		
Long-term debt	2,374.6	1,845.2
DEFERRED CREDITS AND OTHER	.4	.3
COMMON STOCK AND OTHER STOCKHOLDERS' EQUITY	3,475.8	3,282.4
	$ 6,610.0	$ 5,568.0

</TABLE>

See Notes to Condensed Financial Statements.

THE COASTAL CORPORATION AND SUBSIDIARIES
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF THE REGISTRANT

THE COASTAL CORPORATION
STATEMENT OF OPERATIONS
(Millions of Dollars)

	Year Ended December 31, 1998	1997	1996
OPERATING REVENUES	$ -	$ -	$ -
OPERATING COSTS AND EXPENSES	-	-	-
OPERATING PROFIT	-	-	-
OTHER INCOME:			
Equity in net earnings of subsidiaries	455.6	424.8	465.5
Interest income from subsidiaries - net	54.4	63.0	119.2
Other income - net	70.4	62.0	28.3
	580.4	549.8	613.0
OTHER EXPENSES (BENEFITS):			
General and administrative	10.0	11.7	6.6
Interest and debt expense	179.9	166.9	245.4
Taxes on income	(66.4)	(20.9)	(53.6)
	123.5	157.7	198.4
EARNINGS FROM CONTINUING OPERATIONS BEFORE EXTRAORDINARY ITEMS	456.9	392.1	414.6
DISCONTINUED OPERATIONS, NET OF INCOME TAXES:			
Estimated loss on disposal	(12.5)	-	-
EARNINGS BEFORE EXTRAORDINARY ITEM	444.4	392.1	414.6
EXTRAORDINARY ITEM, NET OF INCOME TAXES:			
Loss on early extinguishment of debt	-	(90.6)	(12.0)
NET EARNINGS	$ 444.4	$ 301.5	$ 402.6

See Notes to Condensed Financial Statements.

THE COASTAL CORPORATION AND SUBSIDIARIES
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF THE REGISTRANT

THE COASTAL CORPORATION
STATEMENT OF CASH FLOWS

(Millions of Dollars)

	Year Ended December 31, 1998	1997	1996
Net Cash Flow From Operating Activities:			
Earnings from continuing operations before extraordinary item.......	$ 456.9	$ 392.1	$ 414.6
Items not requiring (providing) cash:			
Depreciation, depletion and amortization........................	.1	.1	.1
Deferred income taxes...	(35.2)	(25.1)	44.8
Undistributed subsidiary earnings...............................	(248.5)	(363.7)	(340.9)
Working capital and other changes, excluding changes relating to cash and non-operating activities:			
Receivables..	2.8	1.8	30.1
Prepaid expenses and other...................................	(1.2)	(.5)	(.3)
Accounts payable and accrued expenses........................	(54.4)	82.6	(76.2)
Other..	(75.6)	(39.9)	(24.2)
	44.9	47.4	48.0
Cash Flow from Investing Activities:			
Purchases of property, plant and equipment.........................	(.2)	(.1)	(.1)
Net change in accounts with subsidiaries...........................	(113.6)	143.2	903.8
Investments in subsidiaries..	(120.3)	(2.5)	(77.2)
	(234.1)	140.6	826.5
Cash Flow from Financing Activities:			
Increase (decrease) in short-term notes............................	123.0	259.0	(268.2)
Proceeds from issuing common stock.................................	5.5	7.3	14.7
Proceeds from long-term debt issues................................	406.9	523.4	-
Redemption of preferred stock......................................	(200.0)	-	-
Payments to retire long-term debt..................................	(10.6)	(933.1)	(549.1)
Dividends paid...	(56.5)	(59.7)	(59.6)
	268.3	(203.1)	(862.2)
Net Increase (Decrease) in Cash and Cash Equivalents..................	79.1	(15.1)	12.3
Cash and Cash Equivalents at Beginning of Year........................	.5	15.6	3.3
Cash and Cash Equivalents at End of Year..............................	$ 79.6	$ .5	$ 15.6

See Notes to Condensed Financial Statements.

THE COASTAL CORPORATION AND SUBSIDIARIES
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF THE REGISTRANT

THE COASTAL CORPORATION
NOTES TO CONDENSED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

Principles of Consolidation - The financial statements of the Company reflect the investment in wholly owned subsidiaries using the equity method.

Statement of Cash Flows - For purposes of this statement, cash equivalents include time deposits, certificates of deposit and all highly liquid instruments with original maturities of three months or less. The Company made cash payments for interest and financing fees of $173.6 million, $178.5 million and $279.0 million in 1998, 1997 and 1996, respectively. Cash payments (refunds - primarily from subsidiaries) for income taxes amounted to $8.5 million, $(97.9) million and $(41.9) million for 1998, 1997 and 1996, respectively.

Federal Income Taxes - The Company follows the liability method of accounting for income taxes as required by the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."

The Company files a consolidated federal income tax return with its wholly owned subsidiaries. Members of the consolidated group with taxable incomes are charged with the amount of income taxes as if they filed separate federal income tax returns, and members providing deductions and credits which result in income tax savings are allocated credits for such savings.

Note 2. Consolidated Financial Statements

Reference is made to the Consolidated Financial Statements and related Notes of Coastal and Subsidiaries for additional information.

Note 3. Debt and Guarantees

Information on the debt of the Company is disclosed in Note 4 of the Notes to Consolidated Financial Statements included herein. The Company has guaranteed certain long-term debt of its subsidiaries and certain other obligations arising in the ordinary course of business. Approximately $241.7 million of guaranteed long-term debt of subsidiaries was outstanding at December 31, 1998, including current maturities. The Company and certain of its subsidiaries have entered into interest rate swaps with major banking institutions. The Company is exposed to loss if one or more counterparties default. In addition, the Company or certain of its subsidiaries are guarantors on certain bank loans of corporations, joint ventures and partnerships in which the Company or certain subsidiaries have equity interests. Information on the guarantees and swaps is disclosed in Notes 4 and 7, respectively, of the Notes to Consolidated Financial Statements.

The aggregate amounts of long-term debt maturities of Coastal for the five years following 1998 are (Millions of Dollars):

1999......................	$ 50.0	2002................	$ 250.0
2000......................	196.3	2003................	102.3
2001......................	84.1		

Note 4. Dividends Received

Cash dividends received from consolidated subsidiaries were as follows: 1998 - $207.1 million, 1997 - $61.1 million and 1996 - $124.6 million.

THE COASTAL CORPORATION AND SUBSIDIARIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
(Millions of Dollars)

<TABLE>
<CAPTION>

Description	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Other	Balance at End of Year
<S>	<C>	<C>	<C>	<C>
Year Ended December 31, 1998				
Allowance for doubtful accounts....................	$16.6	$ 4.0	$(4.7)(A)	$ 15.9
	=====	=====	=====	=======
Year Ended December 31, 1997				

Allowance for doubtful accounts...................	$23.4	$ 4.0	$(10.8)(A)	$ 16.6
	=====	=====	======	=======
Year Ended December 31, 1996				
Allowance for doubtful accounts...................	$21.4	$ 6.0	$(4.0)(A)	$ 23.4
	=====	=====	=====	=======

<FN>

(A) Accounts charged off net of recoveries.
</FN>
</TABLE>

EXHIBIT INDEX

Exhibit Number	Document
3.1+	Restated Certificate of Incorporation of Coastal, as restated on March 22, 1994. (Filed as Module TCC- Artl-Incorp on March 28, 1994).
3.2+	By-Laws of Coastal, as amended on January 16, 1990 (Exhibit 3.4 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1989).
4	(With respect to instruments defining the rights of holders of long-term debt, the Registrant will furnish to the Commission, on request, any such documents).
10.1+	1984 Stock Option Plan (Appendix B to Coastal's Proxy Statement for the 1984 Annual Meeting of Stockholders, dated May 14, 1984).
10.2+	1985 Stock Option Plan (Appendix A to Coastal's Proxy Statement for the 1986 Annual Meeting of Stockholders, dated March 27, 1986).
10.3+	The Coastal Corporation Performance Unit Plan effective as of January 1, 1987 (Exhibit 10.5 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1987).
10.4+	The Coastal Corporation Replacement Pension Plan effective as of November 1, 1987 (Exhibit 10.6 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1987).
10.5+	Description of Coastal's Key Employees Bonus Plan (Exhibit 10.7 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1987).
10.6+	The Coastal Corporation Stock Purchase Plan, as restated on January 1, 1994 (Appendix B to Coastal's Proxy Statement for the 1994 Annual Meeting of Stockholders dated March 29, 1994).
10.7+	The Coastal Corporation Amended and Restated Stock Grant Plan, effective October 9, 1997. (Exhibit 10.7 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)
10.8+	The Coastal Corporation Amended and Restated Deferred Compensation Plan for Directors, effective October 9, 1997. (Exhibit 10.8 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)
10.9+	The Coastal Corporation 1990 Stock Option Plan (Exhibit 10.13 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1989).

10.10+	The Coastal Corporation 1997 Directors Stock Plan, effective June 5, 1997. (Exhibit 10.10 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)
10.11+	The Coastal Corporation Deferred Compensation Plan (Exhibit 10.14 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1993).
10.12+	The Coastal Corporation 1994 Incentive Stock Plan (Appendix A to Coastal's Proxy Statement for the 1994 Annual Meeting of Stockholders dated March 29, 1994).
10.13+	Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, includes Plan as Restated as of January 1, 1989 and First Amendment dated July 27, 1992, Second Amendment dated December 9, 1992, Third Amendment dated October 29, 1993 (Exhibit 10.16 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1993).

Note:

\+ Indicates documents incorporated by reference from the prior filing indicated.

* Indicates documents filed herewith.

EXHIBIT INDEX

Exhibit Number	Document
10.14+	Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, as further amended by the Fourth Amendment dated May 20, 1994, Fifth Amendment dated August 17, 1994, Sixth Amendment dated August 30, 1994, Seventh Amendment dated October 30, 1995, Eighth Amendment dated December 29, 1995 and Ninth Amendment dated December 29, 1995 (Exhibit 10.14 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1995).
10.15+	Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, as further amended by the Tenth Amendment dated March 25, 1996 (Exhibit 10.15 to Coastal's Quarterly Report on Form 10-Q for the period ended March 31, 1996).
10.16+	Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, as further amended by the Twelfth Amendment dated August 29, 1996 and the Thirteenth Amendment dated September 16, 1996 (Exhibit 10.16 to Coastal's Quarterly Report on Form 10-Q for the period ended September 30, 1996).
10.17+	Pension Plan for Employees of The Coastal Corporation as of January 1, 1993, as further amended by the Eleventh Amendment dated December 6, 1996. (Exhibit 10.17 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)
10.18+	Pension Plan for Employee of The Coastal Corporation as of January 1, 1993, as further amended by the Fourteenth Amendment dated December 31, 1997. (Exhibit 10.18 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)
10.19+	Agreement for Consulting Services between The Coastal Corporation and Oscar S. Wyatt, Jr. dated August 1, 1997. (Exhibit 10.19 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1997.)
10.20+	The Coastal Corporation 1998 Incentive Stock Plan, effective March 19, 1998 (Appendix A to Coastal's Proxy Statement for the 1998 Annual Meeting of Stockholders dated March 26, 1998).

11* Statement re Computation of Per Share Earnings.

21* Subsidiaries of Coastal.

23* Consent of Deloitte & Touche LLP.

24* Powers of Attorney (included on signature pages herein).

27* Financial Data Schedule.

99+ Indemnity Agreement revised and updated as of April, 1988 (Exhibit 28 to Coastal's Annual Report on Form 10-K for the fiscal year ended December 31, 1990).

Note:

+ Indicates documents incorporated by reference from the prior filing indicated.

* Indicates documents filed herewith.

Exhibit 11

THE COASTAL CORPORATION AND SUBSIDIARIES
STATEMENT RE COMPUTATION OF PER SHARE EARNINGS
(Millions of Dollars, Except Per Share Amounts, and Thousands of Shares)

<TABLE>
<CAPTION>

	Year Ended December 31, 1998	1997	1996
<S>	<C>	<C>	<C>
BASIC EARNINGS PER SHARE			
Net earnings	$ 444.4	$ 301.5	$ 402.6
Dividends on preferred stock	6.0	17.4	17.4
Net earnings available to common stockholders	$ 438.4	$ 284.1	$ 385.2
Average number of common shares outstanding	212,184	211,518	210,597
Average number of Class A common shares outstanding	359	374	390
	212,543	211,892	210,987
Basic earnings per share:			
From continuing operations before extraordinary items	$ 2.24	$ 1.80	$ 2.33
Discontinued operations	(.18)	(.03)	(.04)
Extraordinary items	-	(.43)	(.46)
Net basic earnings per share	$ 2.06	$ 1.34	$ 1.83
DILUTED EARNINGS PER SHARE			
Net earnings used in calculating basic earnings per share	$ 438.4	$ 284.1	$ 385.2
Dividends applicable to dilutive preferred stock:			
Series A	.1	.1	.1
Series B	.1	.1	.1
Series C	.1	.2	.2
Income available to common shareholders plus assumed conversions	$ 438.7	$ 284.5	$ 385.6
Average number of shares used in calculating basic earnings per share	212,543	211,892	210,987
Effect of dilutive securities:			
Options	2,248	1,798	1,241
Series A, B and C preferred stock	1,317	1,412	1,458
	216,108	215,102	213,686
Diluted earnings per share:			
From continuing operations before extraordinary items	$ 2.21	$ 1.77	$ 2.30
Discontinued operations	(.18)	(.03)	(.04)
Extraordinary items	-	(.42)	(.46)
Net diluted earnings per share	$ 2.03	$ 1.32	$ 1.80

<FN>

Convertible securities and options are not considered in the calculations if the effect of the conversion is anti-dilutive.
</FN>
</TABLE>

Exhibit 21

SUBSIDIARIES OF THE COASTAL CORPORATION

<TABLE>
<CAPTION>

<S>	State or Other Jurisdiction of Incorporation or Organization <C>
Coastal Alliance Pipeline Company, L.L.C.	Delaware
Coastal Capital Corporation	Delaware
Coastal Finance Corporation	Delaware
Coastal Coal, Inc.	Delaware
Coastal Credit, Inc.	Delaware
Coastal Finance I	Delaware
Coastal Gas Services Company	Delaware
ANR Gas Supply Company	Delaware
ANR Transportation Services Company	Delaware
Coastal Electric Services Company	Delaware
Coastal Field Services Company	Delaware
CIG Merchant Company	Delaware
Coastal Gas Gathering and Processing Company	Delaware
Coastal Aux Sable Products Company	Delaware
Coastal Dauphin Island Company, L.L.C.	Delaware
Blacks Fork Gas Processing Company (50%)**	Wyoming*
Coastal States Gas Transmission Company	Delaware
Starr-Zapata Pipe Line (50%)**	Texas*
Coastal Gas Marketing Company	Delaware
CGM, Inc.	Delaware
Engage Energy US, L.P. (50%)**	Delaware*
Coastal Multi-Fuels, Inc.	Delaware
Coastal Pan American Corporation	Delaware
Coastal Southern Pipeline Company	Delaware
Coastal Gas International Company	Delaware
Coastal Gas & Power India I Ltd.	Cayman Islands
Coastal Gas Australia Proprietary Ltd.	Australia
Coastal Gas India Holdings Ltd.	Cayman Islands
Coastal Gas India Ltd.	Cayman Islands
Coastal Gas International Ltd.	Cayman Islands
Coastal Gas Australia Pty Ltd.	Cayman Islands
Coastal Gas International Ventures, Inc.	Delaware
Coastal Gas Storage Victoria Ltd.	Cayman Islands
Coastal Gas Storage Victoria Pty Ltd.	Australia
Coastal Gas Toluca Ltd.	Cayman Islands
Coastal Gas Venezuela Ltd.	Cayman Islands
Coastal Halcon Pipeline I Ltd.	Cayman Islands
Coastal Halcon Pipeline II Ltd.	Cayman Islands
Coastal Gas de Mexico S. de R. L. de C.V.	Mexico
Coastal Horsham Pipeline I Ltd.	Cayman Islands
Coastal Horsham Pipeline II Ltd.	Cayman Islands
Coastal Gas Pipelines Victoria, L.L.C.	Delaware
Coastal Health Management Corporation (94%)	Delaware
Coastal Holding Corporation	Delaware
CIC Industries, Inc.	Delaware
Coastal Chem, Inc.	Delaware
Coastal Pipeline Company	Delaware
Coastal Refining & Marketing, Inc.	Delaware
Coastal Petroleum (Bahamas) Limited	The Bahamas
Coastal Refined Products Corporation	Delaware
Coastal Liquids Transportation, L.P.	Delaware

</TABLE>

SUBSIDIARIES OF THE COASTAL CORPORATION

<TABLE>

<CAPTION>

<S> <C>

	State or Other Jurisdiction of Incorporation or Organization
Coastal Liquids Partners, L.P (32%) **	Delaware*
Coastal States Crude Gathering Company	Texas
Distribuidora Coastal, S.A. de C.V	El Salvador
Lube & Wax Ventures, L.L.C. (50%)**	Delaware
Coastal Catalyst Technology, Inc	Delaware
Coastal Cat Process Marketing, Inc	Delaware
BAR-CO Processes Joint Venture (50%)**	Texas*
Coastal Eagle Point Oil Company	Delaware
Coastal Energy Corporation	Delaware
Coastal Mobile Refining Company	Delaware
Coastal Petrochemical International A.V.V	Aruba
Coastal Petrochemical International (L) Limited	Labuan (Malaysia)
Coastal West Ventures, Inc	Delaware
Coastal Limited Ventures, Inc	Texas
ANR Financial Services, Inc	Delaware
Coastal Mart, Inc	Delaware
Coastal Mart Holdings, Inc	Delaware
Coastal Markets, Ltd	Texas*
TND Beverage Corporation	Texas
Coastal Medical Services, Inc	Delaware
Coastal Midland, Inc	Delaware
Coastal Natural Gas Company	Delaware
American Natural Resources Company	Delaware
ANRFS Holdings, Inc	Delaware
ANR Advance Holdings, Inc. (50%)**	Delaware
ANR Advance Transportation Company, Inc	Delaware
Transport USA, Inc	Pennsylvania
ANR Alliance Transportation Services Company	Delaware
ANR Credit Corporation	Delaware
ANR Development Corporation	Delaware
ANR Real Estate Corporation	Connecticut
ANR Field Services Company	Delaware
ANR Finance B.V	The Netherlands
Coastal Financial B.V	The Netherlands
Coastal Financial Antilles N.V	Netherlands Antilles
Coastal Netherlands Financial B.V	The Netherlands
ANR Independence Pipeline Company	Delaware
ANR Intrastate Gas Company, Inc	Delaware
ANR Pipeline Company	Delaware
ANR Alliance Pipeline Company Canada, Inc	Canada
ANR Alliance Pipeline Company U.S., Inc	Delaware
ANR Atlantic Pipeline Company	Delaware
ANR Capital Corporation	Delaware
ANR Energy Conversion Company	Michigan
ANR Iroquois, Inc	Delaware
ANR New England Pipeline Company	Delaware
ANR Mayflower Company	Delaware
ANR Southern Pipeline Company	Delaware
American Natural Offshore Company	Delaware
Texas Offshore Pipeline System, Inc	Delaware

</TABLE>

SUBSIDIARIES OF THE COASTAL CORPORATION

<TABLE>
<CAPTION>

<S> <C>

	State or Other Jurisdiction of Incorporation or Organization
Unitex Offshore Transmission Company	Delaware
ANR Production Company	Delaware
ANRPC Holdings, Inc	Delaware
ANR Storage Company	Michigan
ANR Blue Lake Company	Delaware
Blue Lake Gas Storage Company (75%)**	Michigan*

ANR Cold Springs Company	Delaware
ANR Eaton Company	Michigan
Eaton Rapids Gas Storage System (50%)**	Michigan*
ANR Jackson Company	Delaware
ANR Northeastern Gas Storage Company	Delaware
Steuben Gas Storage Company (50%)**	New York*
ANR Western Storage Company	Delaware
ANR Venture Eagle Point Company	Delaware
ANR Venture Management Company	Delaware
Capitol District Energy Center Cogeneration Associates (50%)**	Connecticut*
ANR Western Coal Development Company	Delaware
Coastal Coal Company, LLC	Delaware
Coastal Coal - West Virginia, LLC	Delaware
Coastal International Finance Ltd	Honduras
Coastal Offshore Finance Ltd	Cayman Islands
Coastal Offshore Insurance Ltd	Bermuda
Coastal Great Lakes, Inc	Delaware
Great Lakes Gas Transmission Limited Partnership (36%)**	Delaware*
Empire State Pipeline Company, Inc	New York
Empire State Pipeline (50%)**	New York
Mid Michigan Gas Storage Company	Michigan
CIC Stock Corporation	Delaware
CIG Gas Storage Company	Delaware
CIG Resources Company	Delaware
Johnstown Cogeneration Company, LLC (50%)**	Colorado
Keyes Helium Company, LLC (51%)	Colorado
CIG-Canyon Compression Company	Delaware
CIG Gas Supply Company	Delaware
Wyoming Interstate Company, Ltd	Colorado*
CIG Overthrust, Inc	Delaware
CIG Trailblazer Gas Company	Delaware
Colorado Interstate Gas Company	Delaware
CIG Exploration, Inc	Delaware
CIG Field Services Company	Delaware
Great Divide Gas Services, LLC (73%)**	Colorado
Colorado Water Supply Company	Delaware
Colorado Interstate Production Company	Delaware
Great Lakes Gas Transmission Company (50%)**	Delaware
Wyoming Gas Supply, Inc	Delaware
Coastal Oil Chelsea, Inc	Texas
Coastal Oil & Gas Corporation	Delaware
COGC Resale Company	Delaware
Coastal Australia AC 96-3 Ltd	Cayman Islands

</TABLE>

SUBSIDIARIES OF THE COASTAL CORPORATION

<TABLE>
<CAPTION>

<S>	State or Other Jurisdiction of Incorporation or Organization <C>
Coastal Oil & Gas Australia 20 Pty Ltd	Australia
Coastal Australia AC 96-4 Ltd	Cayman Islands
Coastal Oil & Gas Australia 21 Pty Ltd	Australia
Coastal BAS-97 Ltda	Brazil
Coastal BCAM-2 Ltda	Brazil
Coastal Buenos Aires I Ltd	Cayman Islands
Coastal Buenos Aires II Ltd	Cayman Islands
Coastal Buenos Aires III Ltd	Cayman Islands
Coastal Buenos Aires IV Ltd	Cayman Islands
Coastal China Ltd	Cayman Islands
Coastal Colombia Ltd	Cayman Islands
Coastal Development I Ltd	Cayman Islands
Coastal Development II Ltd	Cayman Islands
Coastal Oil & Gas Australia Pty Ltd	Australia
Coastal Development III Ltd	Cayman Islands
Coastal Development IV Ltd	Cayman Islands
CoastalDril, Inc	Delaware

Coastal Javelina, Inc.	Delaware
Coastal Indonesia Bangko Ltd	Cayman Islands
Coastal Indonesia Sampang Ltd	Cayman Islands
Coastal Hungary Ltd	Hungary
Coastal Oil & Gas Holdings, Inc.	Delaware
Coastal Peru Ltd	Cayman Islands
Coastal Peru 73 Ltd	Cayman Islands
Coastal Power Company	Delaware
ANRV-EP, Inc.	Delaware
ANR Eagle Point, L.P.	Delaware
Eagle Point Cogeneration Partnership (50%)**	New Jersey*
Coastal Bangchak Power Ltd	Cayman Islands
Coastal Henan Power Ltd	Cayman Islands
Coastal Henan Power I Ltd	Cayman Islands
Coastal Henan Power II Ltd	Cayman Islands
Coastal Clark Investor Ltd	Cayman Islands
Coastal Clark Manager Ltd	Cayman Islands
Coastal Manager Ltd.	Cayman Islands
Coastal Mexicana Northeast Ltd	Cayman Islands
Coastal Mexicana Northwest Ltd	Cayman Islands
Coastal Nanjing Investor Ltd	Cayman Islands
Coastal Nanjing Power Ltd	Cayman Islands
Coastal Nanjing Manager Ltd	Cayman Islands
Coastal Power Nicaragua Ltd	Cayman Islands
Coastal Palembang Power Ltd	Cayman Islands
Coastal Palembang Power (Singapore) Pte Ltd	Singapore
Coastal Peenya Investor Ltd	Cayman Islands
Coastal Peenya Power Ltd	Mauritius
Peenya Power Company (50%)**	India
Coastal Peenya Manager Ltd	Cayman Islands
Coastal Power Central America Ltd	Cayman Islands
Coastal Power Colorado, LLC (51%)	Delaware
Coastal Power Distribution Ltd	Cayman Islands

</TABLE>

SUBSIDIARIES OF THE COASTAL CORPORATION

<TABLE>
<CAPTION>

<S>	State or Other Jurisdiction of Incorporation or Organization <C>
Coastal Power Dominicana Generation Ltd	Cayman Islands
Coastal Power Guatemala Ltd	Cayman Islands
San Jose Power Holding Company, Ltd. (46%)**	Cayman Islands
Coastal Power India (Cayman) Ltd	Cayman Islands
Coastal Power India I Ltd	Mauritius
Coastal Power International Ltd	Cayman Islands
Compania de Electricidad de Puerto Plata, S.A. (48%)**	Dominican Republic
Energia Coastal Guatemala, S.A.	Guatemala
Coastal Power International II Ltd	Cayman Islands
Quetta Power Holding Company I Ltd. (50%)**	Cayman Islands
Habibullah Coastal Power (Private) Company	Pakistan
Quetta Power Holding Company II Ltd	Cayman Islands
Coastal Power International III Ltd	Cayman Islands
Coastal Power International IV Ltd	Cayman Islands
Coastal Power International V Ltd	Cayman Islands
Coastal Power Khulna Ltd	Cayman Islands
Khulna Power Company Ltd. (73.9%)**	Bangladesh
Coastal Power Lanka Ltd	Cayman Islands
Coastal Power Noapara Ltd Cayman Islands	
Coastal Power Panama Generation Ltd	Cayman Islands
Coastal Power Panama Investor, S.A.	Panama
Coastal Power Pecem Ltd	Cayman Islands
Coastal Saba Investor Ltd	Cayman Islands
Coastal Saba Investor II Ltd	Cayman Islands
Coastal Saba Power Ltd	Mauritius
Saba Power Company (Private) Limited**	Pakistan
Coastal Saba Manager II Ltd	Cayman Islands

Coastal Saba Manager Ltd	Cayman Islands
Coastal Salvadoran Power Ltd	Cayman Islands
Coastal Nejapa Ltd. (90%)	Cayman Islands
Coastal Suzhou Investor Ltd	Cayman Islands
Coastal Suzhou Power Ltd	Cayman Islands
Suzhou New District Cogeneration Company (60%)**	Jiangsu Province, China
Coastal Suzhou Manager Ltd	Cayman Islands
Coastal Gusu Heat & Power Ltd	Cayman Islands
Suzhou Suda Cogeneration Power Company Ltd. (60%)**	China
Coastal Wisconsin Energy, LLC	Wisconsin
Coastal Wisconsin Manager, Inc	Delaware
Coastal Wisconsin Power, Inc	Delaware
Coastal Wuxi Investor Ltd	Cayman Islands
Coastal Wuxi New District Ltd	Cayman Islands
Wuxi Shunda Gas Turbine Company (60%)**	China
Coastal Wuxi Manager Ltd	Cayman Islands
Coastal Wuxi Power Ltd	Cayman Islands
Wuxi Huada Gas Turbine Electric Power Company (60%)**	Jiangsu Province, China
Coastal States Management Corporation	Colorado
ABCO Aviation, Inc	Delaware
ABCO Leasing, Inc	Delaware
ANR Media Company	Michigan

</TABLE>

SUBSIDIARIES OF THE COASTAL CORPORATION

<TABLE>
<CAPTION>

<S>	State or Other Jurisdiction of Incorporation or Organization <C>
Coastal (Cayman Islands) Construction Company Ltd	Cayman Islands
Coastal do Brasil S/C Ltda	Brazil
Coastal Travel Mart, Inc	Delaware
Rancho Paloma Company, S.A. de C.V	Mexico
Coastal States Trading, Inc	Delaware
Coastal Bridger Lake Pipeline Corporation	Delaware
Coastal Technology, Inc	Delaware
Coastal Technology Dominicana, S.A	Dominican Republic
Coastal Technology Ltd	Cayman Islands
Coastal Technology Palembang, Inc	South Dakota
Coastal Technology Palembang (Cayman) Ltd	Cayman Islands
Palembang Coastal Technology (Singapore) Pte Ltd	Singapore
Coastal Technology Pakistan (Private) Limited	Pakistan
Coastal Technology Salvador, S.A. de C.V	El Salvador
Coastal Unilube, Inc	Tennessee
Coastal Unilube of Iowa L.C	Iowa
Cosbel Petroleum Corporation	Delaware
Coastal Canada Petroleum, Inc	New Brunswick, Canada
Engage Energy Canada, L.P. (50%)**	Canada*
Coastal Fuels Marketing, Inc	Florida
Coastal Fuels of Puerto Rico, Inc	Delaware
Coastal Offshore Fuels, Inc	Liberia
Coastal Terminals, Inc	Florida
Coastal Tug and Barge, Inc	Florida
Coastal Oil New England, Inc	Massachusetts
Coastal Oil New York, Inc	Delaware
Coscol Petroleum Corporation	Delaware
Coastal CFC Ltd	Cayman Islands
Coastal Baltica Holding Company Ltd. (50%)**	Cayman Islands
Coastal Baltica Marketing Company Ltd. (50%)**	Cayman Islands
Coastal Coker Corporation Aruba N.V	Aruba
Coastal India Petroleum Ltd	Cayman Islands
Coastal Securities Company Limited	Bermuda
Coastal Aruba Holding Company N.V	Aruba
Coastal Aruba Fuels Company N.V	Aruba
Coastal Aruba Maintenance/Operations Company N.V	Aruba
Coastal Aruba Refining Company N.V	Aruba
Clark Pipeline and Depot Company, Inc. (50%)**	Philippines
Coastal Energy of Panama, Inc	Panama

Coastal Petroleum N.V.	Aruba
Coastal Fuji Oil Ltd. (50%)	Cayman Islands
Coastal Petroleum Argentina, S.A.	Argentina
Coastal Petroleum N.V. Chile Limitada (99%)	Chile*
United Summit Coastal Oil Ltd. (50%)**	Bangladesh
Coastal Petroleum Overseas N.V.	Aruba
Coastal Aruba Investor N.V.	Aruba
Subic Bay Distribution, Inc. (50%)**	Philippines
Subic Bay Energy Company Ltd. (50%)**	Cayman Islands
Subic Bay Fuels Company, Inc. (50%)**	Philippines

</TABLE>

SUBSIDIARIES OF THE COASTAL CORPORATION

<TABLE>
<CAPTION>

<S>	State or Other Jurisdiction of Incorporation or Organization <C>
Subic Bay Petroleum Products Ltd	Cayman Islands
Coastal Belcher Petroleum Pte. Ltd	Singapore
Coastal (Bermuda) Petroleum Limited	Bermuda
Coastal Cayman Finance Ltd	Cayman Islands
Coastal Management Services (Singapore) Pte. Ltd	Singapore
Coastal Petroleum (Far East) Pte Ltd	Singapore
Holborn Oil Trading Limited	Bermuda
Coastal (Subic Bay) Petroleum, Inc	Texas
Coastal Subic Bay Terminal, Inc	Philippines
Coastal Stock Company Limited	Bermuda
Coastal Europe Limited	England
Coastal Services Petroleum (U.K.) Limited	England
Coastal States Petroleum (U.K.) Limited	England
Coastal States Tankers (U.K.) Limited	England
Colbourne Insurance Company Limited	England
Coastal Tankships U.S.A., Inc	Delaware
Coscol Marine Corporation	Texas
Coastal Mart of Oklahoma, Inc	Oklahoma
Coastal Interstate Corporation	Delaware
Golden Carriers Corporation	Liberia
Texas Tank Ship Agency, Inc	Delaware

<FN>

The above subsidiaries, with the exception of those indicated with a double asterisk (**) are included in the Consolidated Financial Statements of The Coastal Corporation. Great Lakes Gas Transmission Company has a 28.06% limited partnership interest in Great Lakes Gas Transmission Limited Partnership. The names of certain subsidiaries have been omitted from the above listing because such subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary. The voting stock of each corporation is owned 100% by its immediate parent or by its immediate parent together with an affiliate of such parent, unless otherwise indicated above.

* Partnership

** Not consolidated

</FN>
</TABLE>

Exhibit 23

CONSENT OF DELOITTE & TOUCHE LLP

We consent to the incorporation by reference in Registration Statements No. 33-21095, 33-40263, 33-53952, 33-5214, 2-97766, 33-5218, 33-42696 and 333-70285 of The Coastal Corporation on Forms S-8 and Registration Statements No. 33-48435, 333-10995, 333-44527, 333-50075 and 333-58981 of The Coastal Corporation on Forms S-3 of our report dated February 4, 1999, appearing in this Annual Report on Form 10-K of The Coastal Corporation for the year ended December 31, 1998.

DELOITTE & TOUCHE LLP

Houston, Texas
March 24, 1999

<TABLE> <S> <C>

<ARTICLE> 5
<LEGEND> THE SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM THE COASTAL CORPORATION FORM 10-K ANNUAL REPORT FOR THE PERIOD ENDED DECEMBER 31, 1998 AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH FINANCIAL STATEMENTS.
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