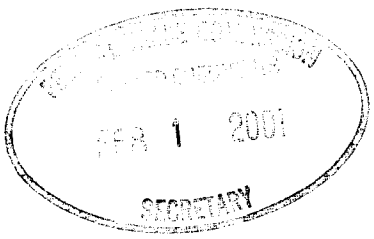
Fried, Frank. Harris, Shriver & Jacobson
1001 Pennsylvania Avenue, NW, Suite 800
Washington, DC 20004-2505
Tel: 202.639.7000
Fax: 202.639.7003 (4) (8)
www.ffhsj.com



Direct Phone: 212.859.8085
Direct Email: linda.blumkin@ffhsj.com

February 1, 2001

Office of the Secretary
Federal Trade Commission
6th Street and Pennsylvania Avenue, N.W.
Room 172
Washington, D.C. 20580

FRIED
FRANK
HARRIS
SHRIVER &
JACOBSON

Re: Request for Approval of Divestiture - El Paso Energy Corporation/ The Coastal Corporation - File No. 001-0086

To : Federal Trade Commission:

Pursuant to § 2.41(f) of the Federal Trade Commission's Rules of Practice, 16 C.F.R. § 2.41(f) (2000) and Paragraph III.C. of the Decision and Order in the above-captioned matter ("the Decision and Order"), El Paso Energy Corporation ("El Paso") hereby requests approval of the sale of the U-T Offshore System, L.L.C. to Mid Louisiana Gas Transmission Company ("MLGT"), a wholly-owned subsidiary of Midcoast Energy Resources, Inc. ("Midcoast"). Capitalized terms not herein defined shall have the same meanings set forth in the Decision and Order. As discussed with Dolores Wood, I am enclosing an original and ten (10) copies of this Public version of the divestiture application and attachments.

Attachments to Request for Approval of Divestitures

A Partnership
Including
Professional
Corporations

New York
Washington
Los Angeles
London
Paris

A. The purchase agreement (with all exhibits and schedules). This agreement is confidential and is not included in the public submission.

B. A description of the divestiture transaction.

C. A description of the purchaser.

D. A market analysis that describes how the sale of this asset to Midcoast will accomplish the Commission's divestiture goals as set forth in the Decision and Order.

E. Midcoast's public documents, including the most recent 10-K filed for the fiscal year ended December 31, 1999; 10-Q filed for the quarterly period ended September 30, 2000; and Proxy Statement for the 2000 annual meeting of shareholders.

If you require further information concerning Midcoast's plans, please contact either I.J. "Chip" Berthelot, Chief Operating Officer, or Chris Kaitson, General Counsel. They can be reached at Midcoast's offices at 1100 Louisiana Street, Suite 3200, Houston, TX, 77002, or by phone at 713-650-8900.

Pursuant to the Order, El Paso is required to complete the divestiture by April 1, 2001. Accordingly, El Paso respectfully requests that this application receive expedited treatment.

Please call me if you have any questions regarding any of the above or need any additional information or documentation.[1]

Sincerely,

Linda Blumkin / JR

LINDA R. BLUMKIN

---

[1] With respect to an accounting of sales and other transactions during the previous year between El Paso and Midcoast, other than ordinary course contracts entered into in 2000 between the parties, the parties are not aware of any material sales or other transactions between the parties or their affiliates in 2000.

Attachment A

The Purchase Agreement

The Purchase Agreement is confidential and is not included in the public submission.

Attachment B

Description of the Divestiture Transaction

On December 22, 2000, Deepwater Holdings, L.L.C. ("Deepwater"), an affiliate of El Paso Energy Corporation ("El Paso"), and Mid Louisiana Gas Transmission Company ("MLGT"), a wholly-owned subsidiary of Midcoast Energy Resources, Inc. ("Midcoast"), executed a Purchase and Sale Agreement pursuant to which Deepwater will sell to MLGT all of Deepwater's right, title and interest in and to the outstanding membership interests in U-T Offshore System, L.L.C., a Delaware limited liability company ("UTOS"). Deepwater owns a 100% membership interest in UTOS, which is the owner of the UTOS Assets, required to be divested by the Decision and Order. The UTOS Assets include the UTOS Pipeline System and the Johnson Bayou Plant. By selling the Deepwater interest in UTOS, El Paso will have divested all of its interest in the UTOS Assets, as required by the Decision and Order.

MLGT also intends to enter into a Transition Services Agreement (included as part of Attachment A) with El Paso Energy Partners, L.P. ("Energy Partners"), an affiliate of Deepwater, to provide necessary administrative, operational and other similar services as appropriate to effect the orderly transfer of ownership of UTOS to MLGT.

MLGT also intends to enter into an Operating Services Agreement (also included as part of Attachment A) with El Paso Energy Partners Operating Company, L.L.C. ("EPEPOC"), an affiliate of Deepwater, pursuant to which EPEPOC will provide field operations, measurement and related services in support of the UTOS Pipeline. EPEPOC is an experienced pipeline operator and performed the same services while Deepwater owned the UTOS pipeline. The services provided by EPEPOC are operational in nature and will not affect the ability of MLGT to compete as an independent entity using the UTOS Pipeline.

The Agreement contains the usual and customary conditions to closing, including Commission approval of the transaction, which approval is also required by the Decision and Order. The parties have requested confidential treatment with respect to the terms and conditions of the Agreement.

Attachment C

Description of the Purchaser - Midcoast Energy Resources, Inc.

Midcoast, along with its subsidiaries and affiliated companies, is an experienced provider of natural gas transportation, gathering, processing and marketing services. It operates primarily in the Gulf Coast and Mid-Continent regions, and owns natural gas systems representing approximately 4,000 miles of pipeline with total throughput of approximately 3 Bcf per day. For the year ended December 31, 1999 it reported revenues of $391.6 million and total assets of $478.4 million.

Midcoast also has extensive experience integrating pipeline acquisitions, as it has closed deals involving 73 different pipelines with an aggregate value of approximately $369 million since the first quarter of 1996. The UTOS transaction offers Midcoast access to a new source of natural gas, as it does not presently own any assets in the West Central Gulf area.

Attachment D

Market Analysis

In its complaint, the Federal Trade Commission ("Commission") alleged that El Paso's acquisition of Coastal might substantially reduce competition in the transportation of natural gas out of the West Central Gulf, including producing areas known as the northern West Cameron Area, the northwestern West Cameron Area, Northern West Cameron West Addition Area, the West Cameron 167 Area, the West Cameron West Addition and South Addition Areas, and the west-central Gulf deepwater area, all in the Gulf of Mexico off the coast of the State of Louisiana. In particular, the Commission alleged that UTOS is a direct and substantial horizontal competitor of several additional pipelines owned by El Paso after the merger.

Without agreeing with the Commission that El Paso's acquisition of UTOS would have substantially lessened competition in the West Central Gulf, the sale of UTOS to Midcoast will add an effective competitor for the transportation of natural gas out of producing fields in the West Central Gulf. As noted above, Midcoast is an experienced operator in the natural gas gathering and transportation business and offers a range of related services.

Midcoast's acquisition of UTOS does not raise any competitive issues, as they are a new entrant in the West Central Gulf. Although Midcoast owns other natural gas pipelines in the Gulf of Mexico, none of those pipelines serve the areas identified by the Commission as part of the West Central Gulf. In view of the above, the parties believe that the sale of UTOS to Midcoast resolves the Commission's concerns as reflected in the Complaint and complies with the Decision and Order.

Attachment E

Midcoast Public Documents

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 FOR THE FISCAL YEAR ENDED DECEMBER 31, 1999

OR

[_] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM _____ TO _____

Commission File Number: 0-8898
MIDCOAST ENERGY RESOURCES, INC.
(Exact Name of Registrant as Specified in its Charter)

TEXAS (State or Other Jurisdiction of Incorporation or Organization)	76-0378638 (I.R.S. Employer Identification No.)
1100 Louisiana, Suite 2950 Houston, Texas (Address of Principal Executive Offices)	77002 (Zip Code)

Registrant's Telephone Number, Including Area Code: (713) 650-8900

Securities Registered Pursuant To Section 12(b) Of The Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, Par Value $.01 Per Share	American Stock Exchange

Securities Registered under Section 12(g) of the Act: none

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act during the preceding 12 months (or for such shorter period that registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [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. [_]

State The Aggregate Market Value of The Voting Stock Held By Non-Affiliates of The Registrant.

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of March 27, 2000, computed by reference to the closing sale price of the registrant's common stock on the American Stock Exchange on such date: $203,029,515.

Common Stock, par value $.01 per share. Shares outstanding on March 27, 2000 was 12,494,124.

DOCUMENTS INCORPORATED BY REFERENCE

List hereunder the following documents if incorporated by reference and the Part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: Portions of Midcoast Energy Resources, Inc. definitive Proxy Statement for the 1999 Annual Meeting of Shareholders, to be filed not later than 120 days after the end of the fiscal year covered by this report, are incorporated by reference into Part III.

MIDCOAST ENERGY RESOURCES, INC.

TABLE OF CONTENTS

CAPTION		PAGE
Glossary		3
	PART I	
Item 1.	Business	4
Item 2.	Properties	13
Item 3.	Legal Proceedings	13
Item 4.	Submission of Matters to a Vote of Security Holders	13
	PART II	
Item 5.	Market for the Registrant's Common Equity and Related Shareholder Matters	14
Item 6.	Selected Financial Data	15
Item 7.	Management's Discussion and Analysis of Financial Condition and Results	16
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	23
Item 8.	Financial Statements	25
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	52
	PART III	
Item 10.	Directors and Executive Officers of the Registrant	52
Item 11.	Executive Compensation	52
Item 12.	Security Ownership of Certain Beneficial Owners and Management	52
Item 13.	Certain Relationships and Related Transactions	52
	PART IV	
Item 14.	Exhibits, Financial Statement Schedules, and Reports on Form 8-K	52

GLOSSARY

The following abbreviations, acronyms or defined terms used in this Form 10-K are defined below:

Bbl	42 U.S. gallon barrel
Bcf	Billion cubic feet
Board	Board of Directors of Midcoast Energy Resources, Inc.
Btu	British thermal unit
Common Stock	Midcoast common stock, par value $.01 per share
Company	Midcoast Energy Resources, Inc., its subsidiaries and affiliated companies
CO2	Carbon dioxide
DPI	Dufour Petroleum, Inc., a wholly owned subsidiary of Midcoast Energy Resources, Inc.
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EPS	Diluted earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
KPC Acquisition	The November 1999 acquisition of Kansas Pipeline Company and MarGasCo
KPC System	A 1,120 mile interstate transmission pipeline
LDC	Local distribution company
LIBOR	London Inter Bank Offering Rate
Mcf/day	One Thousand cubic feet of gas per day
MCOC	Midcoast Canada Operating Corporation, a wholly owned subsidiary of Midcoast Energy Resources, Inc.
Midcoast	Midcoast Energy Resources, Inc.
MIDLA Acquisition	The October 1997 acquisition of the MLGC and MLGT Systems
MIT Acquisition	The May 1997 acquisition of the MIT and TRIGAS Systems
MIT System	A 288-mile interstate transmission pipeline
MGSI	Midcoast Gas Services, Inc.
MLGC	Mid Louisiana Gas Company
MLGC System	A 386-mile interstate transmission pipeline
MLGT	Mid Louisiana Gas Transmission Company
MLGT System	A Louisiana intrastate pipeline
MMBtu	Million British thermal units
MMcf/day	Million cubic feet of gas per day
MMI	Midcoast Marketing Inc.
NGL	Natural gas liquid
NOL	Net operating loss
NYMEX	New York Mercantile Exchange
Preferred Stock	Midcoast preferred stock, par value $.01 per share
Republic	Republic Gas Partners L.L.C.
SeaCrest	SeaCrest Company, L.L.C., a 70% owned subsidiary of Mid Louisiana Gas Transmission Company, which is a wholly owned subsidiary of Midcoast Energy Resources, Inc.
SIGCO	Southern Industrial Gas Corporation
SFAS	Statement of Financial Accounting Standards
TRIGAS System	Two end-user pipelines in northern Alabama

PART I

ITEM 1. BUSINESS.

GENERAL

The Company, along with its subsidiaries and its affiliated companies, is primarily engaged in the transportation, gathering, processing and marketing of natural gas and other petroleum products. As of December 31, 1999, the Company owned and operated three interstate transmission pipeline systems, one intrastate transmission system, 35 end-user systems and 42 gathering systems representing approximately 4,000 miles of pipeline with an aggregate daily throughput capacity of over 3 Bcf of natural gas per day. Operations also included gas processing and treating facilities and over 80 natural gas liquid and crude oil tanks and rail cars. The Company's principal business consists of providing transportation services to both end-users and natural gas producers, providing natural gas marketing services to these customers and processing natural gas. In connection with these services, the Company acquires and constructs pipelines to meet these customers' needs. The Company's principal assets are located in the Gulf Coast and Mid-Continent areas.

The Company originally was incorporated as a Nevada corporation in 1992 and subsequently reincorporated as a Texas corporation in 1999. The Company leases its principal executive offices at 1100 Louisiana, Suite 2950, Houston, Texas 77002, and its telephone number is (713) 650-8900. The Company also owns or leases other regional offices in Alabama, Kansas, Louisiana, Mississippi, Texas and Alberta, Canada.

BUSINESS GROWTH STRATEGY

The Company's principal business strategy is to increase its earnings and cash flow by focusing on accretive acquisitions, pursuing pipeline system and processing facility construction and expansion opportunities and improving the profitability of these systems through volume growth initiatives and cost savings opportunities. The Company implements this strategy through the following steps:

Accretive Acquisitions

The Company seeks to acquire natural gas or petroleum liquids transmission, end-user and gathering pipeline systems and processing plants that offer the opportunity for operational synergies and the potential for increased utilization and expansion of the system. The Company targets systems in its core geographic areas of operation in order to capitalize on existing infrastructure, personnel and customer relationships to maximize system profitability. The Company also seeks to acquire assets in other areas with growing demand for natural gas or increasing drilling activity. These acquisitions enable the Company to establish new core areas in which to build a regional presence. For example, the Company purchased the Anadarko gas gathering system located in Texas and Oklahoma in September 1998. The 696-mile natural gas gathering system and processing plant are located in a prolific natural gas producing region and established a new core geographic area for the Company. The Company quickly strengthened its position in this area in December 1998 with the acquisition of the 35-mile Mendota natural gas gathering system. This system, which included another processing facility, was interconnected with the Anadarko system, providing access to additional areas of natural gas production.

Construction and Expansion Opportunities

The Company leverages its existing infrastructure and customer relationships by constructing systems to meet new or increased demand for pipeline transportation services. These projects include expansion of existing systems and construction of new pipeline or processing facilities. For example, earlier this year the Company constructed new facilities near the southern end of the MIDLA system to provide approximately 55 MMcf per day of high pressure natural gas to two industrial customers. In November 1999, the Company agreed to construct additional facilities for one of these customers to supply up to 80 MMcf per day of natural gas to their natural gas processing plants near Baton Rouge, Louisiana.

Improving Existing System Profitability

After a system is acquired or constructed, the Company begins an aggressive effort to market directly to both producers and end-users in order to fully utilize the system's capacity. As part of this process, the Company focuses on providing quality service to its existing customers while identifying new customers. Many of the Company's existing pipeline and processing systems were designed with excess throughput capacity that provides the Company with opportunities to increase throughput with little incremental cost and to facilitate higher margin "swing" sales during periods of increased natural gas demand. For example, following the purchase of the MIT system in May 1997, the Company had increased firm transportation volumes 29% to 170 MMcf per day by the Spring of 1999 from 132 MMcf per day with

minimal additional capital outlays. In addition, the Company generally seeks to achieve administrative and operational efficiencies by capitalizing on the geographic proximity of many of its systems.

SIGNIFICANT ACQUISITIONS

Since the first quarter of 1996, the Company has acquired ownership of, or interests in, 73 pipelines including four natural gas processing plants for an aggregate cost of approximately $369 million. The following is a summary of the Company's significant acquisition activities:

The MIT Acquisition

In May 1997, the Company acquired the pipeline and energy services operations of Atrion Corporation for cash consideration of $38.2 million and up to $2 million in contingent deferred payments. These operations include (i) a 295-mile interstate transmission pipeline located in northern Alabama, Mississippi and southern Tennessee which transports natural gas to industrial and municipal customers, (ii) a 38-mile and a one-mile pipeline in northern Alabama which primarily serve two large industrial customers and (iii) a natural gas marketing company which was subsequently merged into MMI.

The MIDLA Acquisition

In October 1997, the Company completed its merger with Republic, which owned MLGC, MLGT, and Mid Louisiana Marketing Company that was subsequently merged into MMI. Consideration for the acquisition included $3.2 million in cash, the assumption of approximately $19.1 million in bank indebtedness, the issuance of 481,247 shares of the Company's common stock and warrants to acquire 171,880 shares of common stock. The assets acquired included (i) a 405-mile interstate natural gas pipeline which runs from the Monroe gas field in northern Louisiana, southward through Mississippi to Baton Rouge, Louisiana, (ii) three end-user natural gas pipelines with a collective length of 40 miles and (iii) two offshore lateral natural gas gathering pipelines with a collective length of 8.6 miles. These pipelines serve a number of large industrial and municipal customers.

The Anadarko Acquisition

In September 1998, the Company purchased the Anadarko gas gathering system from El Paso Energy Corporation. The pipeline system was purchased for cash consideration of $35 million.

Under the agreement, MGSI acquired ownership and operation of the Anadarko gas gathering system located in Beckham and Roger Mills counties, Oklahoma and Hemphill, Roberts and Wheeler counties, Texas. The system is comprised of over 696 miles of pipeline with an average throughput of 157 MMcf/day and a total capacity of 345 MMcf/day ("Anadarko System"). The system gathers gas from approximately 250 wells and includes a 40 MMcf/day natural gas processing facility ("Hobart Plant"), 11 compressor stations with a total of over 14,000 horsepower and interconnections with eight major interstate and intrastate pipeline systems.

The Company expanded the Anadarko System in December 1998 with the acquisition of the Mendota system from Seagull Energy Corporation for $3.75 million. The Mendota system, which was interconnected with the Anadarko System, included two processing facilities and 35 miles of natural gas gathering pipeline.

The Calmar Acquisition

In March 1999, the Company purchased the Calmar system in Alberta, Canada from Probe Exploration, Inc. ("Probe"). The total value of the transaction was approximately $13.2 million (U.S.). The assets purchased included a 30 MMcf/day amine sweetening plant, 30 miles of gas gathering pipeline and approximately 4,000 horsepower of compression located near Edmonton, Alberta. The Calmar system currently gathers and treats sour gas from wells operated by Probe and Courage Energy Inc. In conjunction with the purchase, Probe entered into a gas gathering and treating agreement with the Company, including the long-term commitment of Probe's reserves in the Leduc Field, a right of first refusal agreement on new or existing midstream assets within a defined 390-square mile area of interest, and an assignment to the Company of an existing third party gathering and treating agreement.

The Flare and DPI Acquisitions

In March 1999, the Company purchased two related companies, Flare and DPI. The total value of the transaction was approximately $11.1 million and could include future consideration should certain contingencies be met. The Flare and DPI shareholders received cash consideration of approximately $3.2 million, the Company assumed $5.5 million in debt and the DPI shareholders received 163,719 shares of

the Company's common stock. Flare is a natural gas processing and treating company whose principal assets include 27 mobile natural gas processing and treating plants from which it earns revenues based on treating and processing fees and/or a percentage of the NGL's produced. DPI is an NGL, crude oil and CO2 transportation and marketing company. DPI operates 43 NGL and crude oil trucks and trailers, a fleet of 40 pressurized railcars and in excess of 400,000 gallons of NGL storage facilities and product treating and handling equipment.

The Tinsley Acquisition

In March 1999, the Company purchased the Tinsley crude oil gathering pipeline for $5.2 million. The Tinsley system is located in Mississippi and consists of 60 miles of crude oil gathering pipeline, related truck and Mississippi River barge loading facilities and 170,000 barrels of crude oil storage. The system transports approximately 5,000 barrels of crude oil per day both directly from producing wells and from oil trucked to the pipeline.

The Kansas Pipeline Company Acquisition

In November 1999, the Company acquired KPC and other related entities for approximately $195.2 million. KPC owns and operates a 1,120 mile regulated interstate natural gas pipeline system. The system extends into two major segments from northwestern and northeastern Oklahoma through Wichita into the Kansas City metropolitan area. The system's two principal customers are divisions of ONEOK, Inc. and Southern Union Company, which are the local distribution companies for Wichita and Kansas City. KPC derives 97% of its gross margin from a series of long-term transportation contracts with these two principal customers. KPC is capable of delivering approximately 140 MMcf/day and 21 MMcf/day of natural gas into the Kansas City and Wichita marketplaces, respectively. KPC is one of only three pipeline systems currently capable of delivering gas into the Kansas City metropolitan market.

In conjunction with the acquisition of KPC, the Company opted to terminate a revenue sharing agreement with Management Resources Group, LLC by agreeing to pay approximately $10.8 million on or before January 31, 2000. The full amount was accrued as of December 31, 1999.

The Gloria Acquisition

In December 1999, the Company completed the acquisition of the Gloria system from Koch Industries for cash consideration of approximately $6.1 million. The Gloria system is comprised of approximately 133 miles of pipeline with a 1,650 horsepower compressor station and includes 51 miles of natural gas gathering pipeline and 82 miles of transmission pipeline. The system gathers gas from seven producing fields and also directly supplies natural gas to an industrial customer and an LDC. The pipeline was part of Koch's interstate system and FERC approval for the system's abandonment from interstate service was received in October of 1999, which, following the expiration of the required notice period, enabled us to proceed to close the Gloria system acquisition.

2000 Activity

In January 2000, the Company entered into a definitive purchase and sale agreement to acquire the Manyberries Pipeline System ("MBPL") in Canada from Triumph Energy Corporation for cash consideration of approximately $5.7 million (U.S.), plus certain future contingent payments based on the actual throughput volumes. MBPL consists of 90 miles of crude oil pipeline that originates at the Manyberries Oil Field and terminates at an interconnection with the Milk River Pipeline system in southeastern Alberta, Canada. Truck terminals, including the Legend terminal, and a significant amount of crude oil storage also contribute to the operations. The system has a design capacity of approximately 21,000 Bbl's/day and transports light sour crude oil from the Manyberries Oil Field, as well as additional crude oil volumes from the Legend truck terminal. The pipeline system is the only light gravity system in southern Alberta, and current volumes are approximately 6,500 Bbl's/day. Closing is anticipated in the second quarter of 2000, subject to receipt of the approvals, consents or other authorizations required by the Investment Canada Act.

In March 2000, the Company acquired the Provost natural gas plant and gathering system from NovaGas Canada LP, a division of TransCanada, for approximately $4.9 million (U.S.). The Provost acquisition includes 80 miles of natural gas gathering pipeline and a 15 MMcf/day sour gas processing plant and sour gas injection well. The system is located in east-central Alberta, Canada and is the only sour natural gas gathering and processing system in the area. The system is connected to 21 oil tank batteries and primarily gathers the associated sour natural gas production from approximately 900 wells in the Provost area.

SEGMENTS

Beginning in 1998, the Company segregated its business activities into three segments: Transmission Pipelines, End-User Pipelines, and Gathering Pipelines and Natural Gas Processing. These segments are analyzed independently by management and derive revenue from different sources. For financial information related to each segment, see Results of Operations in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," as well as "Note 16. Segment Data, in the Notes to the Consolidated Financial Statements." Set forth below is a description of the principal business activities conducted by each of the segments:

Transmission Pipelines

The Company's transmission pipelines primarily receive and deliver natural gas to and from other pipelines, and secondarily involve end-user or gathering functions. Transportation fees are received by the Company for transporting gas owned by other parties through the Company's pipeline systems. The Company seeks to further expand its activities in this area through the acquisition or construction of natural gas transmission pipelines in its core geographic areas of operation where operational synergies and market opportunities exist or in new geographic regions where there is increasing demand for natural gas by municipal and industrial users. As of December 31, 1999, the Company owned three interstate transmission pipelines and one intrastate transmission pipeline.

End-User Pipelines

The Company also contracts with industrial customers, municipalities or electric generating facilities to provide natural gas and natural gas transportation services to their facilities through interconnected gas pipelines constructed or acquired by the Company. These pipelines provide a direct supply of natural gas to new industrial facilities or to existing facilities as an alternative to the local distribution company. The Company intends to continue to pursue direct sales to these end-users who have the flexibility to negotiate their natural gas purchase and transportation contracts as a result of industry deregulation. Frequently, the Company is able to offer its end-user customer lower rates than the customer's current energy supplier. The Company's contracts with end-user customers typically provide for the payment of a transportation fee by the customer based on the volume of natural gas transported through the Company's pipeline. As of December 31, 1999, the Company owned 35 end-user transmission pipelines.

Gathering Pipelines and Natural Gas Processing

The Company's gathering systems typically consist of a network of pipelines which collect natural gas or crude oil from points near producing wells and transport it to larger pipelines for further transmission. Gathering systems may include meters, separators, dehydration facilities and other treating equipment owned by the Company or others. The Company derives revenues from gathering systems by transporting natural gas or crude oil owned by others through its pipelines for a transportation fee, by purchasing natural gas and utilizing its pipelines to transport the natural gas to a customer in another location where the natural gas is resold or, in certain instances, by purchasing natural gas and arranging for the delivery and resale of an equivalent quantity of natural gas to a customer not directly served by the Company's pipelines. Transactions with customers not directly served by the Company's pipelines are typically accomplished by entering into agreements whereby the Company exchanges natural gas in its pipelines for natural gas in the pipelines of other natural gas transmission companies. The Company intends to pursue the acquisition or construction of additional gas gathering systems in or near its core geographic operating areas and where drilling activity is expected to provide opportunities for the expansion of gathering or processing facilities. As of December 31, 1999, the Company owned an interest in and operated 42 gathering systems.

The Company's natural gas processing revenues are realized from the extraction and sale of NGL's as well as the sale of the residual natural gas. These revenues occur under processing contracts with producers of natural gas utilizing both a "percentage of proceeds" and "keep-whole" basis. The contracts based on percentage of proceeds provide that the Company receives a percentage of the NGL's and residual gas revenues as a fee for processing the producer's gas. The keep-whole contracts require that the Company reimburse the producers for the Btu energy equivalent of the NGL's and fuel removed from the natural gas as a result of processing and the Company retains all revenues from the sale of the NGL's. Once extracted, the NGL's are further fractionated in the Company's facilities into products such as ethane, propane, butanes, natural gasoline and condensate, then sold to various wholesalers along with raw sulfur from the Company's sulfur recovery plant. The Company's processing margins can be adversely affected by declines in NGL prices, declines in gas throughput, or increases in shrinkage or fuel costs, and in the case of "keep-whole" contracts, margins can be affected by rising natural gas prices. As of December 31, 1999, the Company owned four processing and treating plants with a capacity of 100 MMBtu/day.

The Company also owns and operates 43 NGL and crude oil trucks and trailers and a fleet of 40 pressurized railcars.

Gas Marketing Services On Segments

In addition, the Company provides natural gas marketing services to its customers within each of the three segments. The Company's natural gas marketing activities have been focused on the Company's systems with a strategic focus to provide quality and consistent service to customers connected to the Company's pipeline network. The Company's marketing activities include providing natural gas supply and sales services to some of its end-user customers by purchasing the natural gas supply from other marketers or pipeline affiliates and reselling the natural gas to the end-user. The Company also purchases natural gas directly from well operators on many of the Company's gathering systems and resells the natural gas to other marketers or pipeline affiliates. Many of the contracts pertaining to the Company's natural gas marketing activities are month-to-month spot market transactions with numerous gas suppliers or producers in the industry. The Company also offers other gas services to some of its customers including management of capacity release and gas balancing.

Typically, the Company purchases natural gas at a price determined by prevailing market conditions. Simultaneous with the purchase of natural gas by the Company, the Company generally resells natural gas at a higher price under a sales contract that is comparable in its terms to the purchase contract, including any price escalation provisions. In most instances, natural gas marketing is characterized by small margins since there are numerous companies of greatly varying size and financial capacity who compete with the Company in the marketing of natural gas. The profitability of the natural gas marketing operations of the Company depends in large part on the ability of the Company's management to assess and respond to changing market conditions in negotiating these natural gas purchase and sale agreements. As a consequence of the increase in competition in the industry and volatility of natural gas prices there has been a reluctance of end-users to enter into long-term purchase contracts. Moreover, consumers have shown an increased willingness to switch fuels between natural gas and alternate fuels in response to relative price fluctuations in the market. The inability of management to respond appropriately in changing market conditions could have a negative effect on the Company's profitability. Accordingly, historical operating income associated with this revenue stream has varied depending on market conditions. The Company's natural gas marketing activities, which utilize third party pipelines, also expose the Company to economic risk resulting from imbalances or nominated volume discrepancies, which can result either in penalties having a negative impact on earnings or a transaction gain, depending on how and when imbalances are corrected. The Company believes the marketing of natural gas is an important complement to its transportation services.

MAJOR CUSTOMERS

The Company's principal customers are industrial end-users, municipalities, resellers and producers of natural gas. The Company typically enters into three to ten year transportation agreements, which may also include provisions regarding guaranteed minimum volumes and price reductions after the customer meets certain transportation commitments. The Company also enters into marketing agreements with many of its customers related to natural gas supply and other services. For its FERC regulated entities, the Company enters into firm and interruptible transportation contracts using the tariff rates approved by FERC. In certain situations, the Company has offered discounts from its tariffs in response to specific market conditions.

For 1999 and 1998, there were no customers that represented greater than 10% of the Company's gross margin. For 1997, Champion International Corporation and Entergy Gulf States, Inc. each contributed in excess of 10% of the Company's gross margin.

COMPETITION

The Transmission Pipeline, End-user Pipeline, and Gathering Pipeline and Natural Gas Processing segments are highly competitive. In marketing natural gas, the Company has numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil companies and local and national natural gas gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Many of these competitors, particularly those affiliated with major integrated oil and interstate and intrastate pipeline companies, have financial resources substantially greater than those available to the Company. Local utilities and distributors of natural gas are, in some cases, engaged directly, and through affiliates, in marketing activities that compete with the Company. Some of the Company's contracts are month-to-month arrangements and as such, these agreements are affected by competitive factors at the time of the sale.

The Company competes against other companies for supplies of natural gas and for customers. Competition for natural gas supplies is primarily based on efficiency, reliability, availability of transportation and the ability to offer a competitive price for natural gas. Competition for customers is primarily based upon reliability and price of deliverable natural gas. For customers that have the capability of using alternative fuels, such as oil and coal, the Company also competes against companies capable of providing these alternative fuels at a competitive price.

NATURAL GAS SUPPLY

The Company's transmission and end-user pipelines have connections with major interstate and intrastate pipelines that management believes have supplies of natural gas in excess of the volumes required for these systems. However, these purchase contracts may be affected by factors beyond both the Company's and the gas suppliers' control, such as capacity constraints and temporary regional supply shortages. With regard to its gathering systems, supply risks include other parties having control over the drilling of new wells, the inability of wells to deliver natural gas at required pipeline quality and pressure, and depletion of reserves. The future performance of the Company will depend to a great extent on the throughput levels achieved by the Company with respect to its existing pipelines and the pipelines acquired or constructed by it in the future. In order to maintain the throughput on its gathering systems at current levels, the Company must access new natural gas supplies to offset the natural decline in reserves as such supplies are produced. In connection with the construction and acquisition of its gathering systems, evaluations were made of well and reservoir data furnished by producers to determine the availability of natural gas supply for the systems. Based on those evaluations, it is management's belief that there should be adequate natural gas supply for the Company to recoup its investment with an adequate rate of return. As such, management does not routinely obtain independent evaluation of reserves dedicated to its systems due to the cost of such evaluations. Accordingly, the Company does not have estimates of total reserves dedicated to its systems or the anticipated life of such producing reserves.

RATE AND REGULATORY MATTERS

Various aspects of the transportation of natural gas are subject to or affected by extensive federal regulation under the Natural Gas Act ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"), as well as various regulations promulgated by the FERC.

Interstate Pipeline Regulation

Our operations of the MIT, MIDLA and the KPC systems constitute the operations of a "natural gas company," as defined in the NGA. As such, these operations are subject to the jurisdiction of the FERC. The interstate pipeline operations of these systems are operated pursuant to certificates of public convenience and necessity and other authorizations issued under the NGA and pursuant to the NGPA. The FERC regulates the interstate transportation of and certain sales of natural gas, including, among other things, rates and charges allowed natural gas companies, extensions and abandonment of facilities and service, rates of depreciation and amortization and certain accounting methods.

Pipeline rates for the MIT, MIDLA and the KPC systems must be filed with and approved by the FERC. They are regulated by the FERC on a cost-of-service basis and must be deemed by the FERC to be "just and reasonable." The FERC may suspend for up to five months the effectiveness of rate changes filed by the pipeline, and/or permit a changed rate to go into effect subject to refund. The FERC may require the pipeline to refund, with interest, all or any portion of any increased amount collected under "subject to refund" rates that, in the FERC's final determination, is found not to be just and reasonable. The FERC may also investigate, either on its own motion or pursuant to protests by third parties, the lawfulness of pipeline rates that are on file.

In April 1993, jurisdictional rates for the MIT system were increased from rates that had been in effect since April 1990. This rate increase was agreed to in an uncontested settlement with the MIT system's customers that the FERC approved in December 1993. That agreement was amended in September 1996 to eliminate the requirement that a new rate case be filed in September 1996 or any year thereafter. As part of that agreement, rates on the MIT system were reduced 6% effective September 1996.

In June 1996, a decrease in the jurisdictional rates for the MIDLA system was proposed from rates that had been in effect since 1990. This rate decrease was agreed to in an uncontested settlement with MIDLA's customers and was certified to the FERC by the presiding Administrative Law Judge in November 1996. Accordingly, the FERC approved the settlement by letter order dated March 28, 1997. As part of that agreement, MIDLA is not required to file a new rate case.

The Kansas Pipeline Company Acquisition

The pipeline assets of KPC were held in three partnerships prior to May 11, 1998. KansOk Partnership owned intrastate pipelines whose rates were regulated by state agencies or the FERC. Kansas Pipeline Partnership owned an intrastate pipeline in Kansas whose rates were determined by the Kansas Corporation Commission. Riverside Pipeline Company, L.P., owned interstate assets in Kansas, Oklahoma and Missouri that connected the assets of the other two partnerships at the state lines of Missouri, Kansas, or Oklahoma.

Effective May 11, 1998, after more than two years of jurisdictional proceedings before the FERC, the FERC asserted jurisdiction over the assets of these three entities, which were combined into a single, FERC-regulated entity, KPC. The new company's initial rates, by order of FERC, were approximately equal to its then-existing rates. FERC also ordered the company to file a Section 4 Rate Case by September 10, 1999.

In accordance with the FERC's order, KPC filed a rate case pursuant to Section 4 of the NGA on August 27, 1999 (FERC Docket No. RP99-485-000). KPC's proposed rates reflect an annual revenue increase when compared to its initial FERC-approved rates. The rates have been protested by KPC's two principal customers and by the state public utility commissions that regulate them. On September 30, 1999, the FERC issued an order that set KPC's proposed rates for hearing and accepted and suspended the rates to be effective March 1, 2000, subject to possible refund. The Section 4 rate case proceeding will determine whether the rates proposed by KPC for interstate transportation of natural gas are just and reasonable, and the extent to which KPC must refund all or any part of the proposed rate increase that it charges to its customers prior to approval. A procedural schedule in the case has been adopted by the Presiding Administrative Law Judge. A hearing date is set for September 26, 2000.

Intrastate Pipeline Regulation

The Company's intrastate pipeline operations are generally not subject to regulation by the FERC, but they are subject to regulation by various agencies of the states in which we operate. The Magnolia and Gloria systems are subject to the jurisdiction of the FERC with respect to the transportation rates under NGPA Section 311. Under NGPA Section 311, an intrastate pipeline can provide transportation service "on behalf of" any interstate pipeline or LDC served by an interstate pipeline company without prior FERC authorization. Specifically, the FERC adopted a so-called "transport" or "title" standard requiring that, for purposes of interstate transportation under NGPA Section 311, the "on behalf of entity" must either (i) have physical custody of or (ii) hold title to the gas at some point during the transaction. NGPA Section 311 service must be provided without undue discrimination or preference and is subject to certain FERC filing and reporting requirements.

The end-user pipelines and the transmission pipelines not regulated by the FERC are subject to the regulations of the state agencies of the states in which they are located. Most states have agencies that possess the authority to review and authorize transactions, construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates and contract pricing to ensure their reasonableness.

Gathering Pipeline Regulation

The NGA exempts gas gathering facilities from the direct jurisdiction of the FERC. The Company believes that its gathering facilities and operations meet the current tests that the FERC uses to grant non-jurisdictional gathering facility status. Some of the recent cases applying these tests in a manner favorable to the determination of our non-jurisdictional status are still subject to rehearing and appeal. In addition, the FERC's articulation and application of the tests used to distinguish between jurisdictional pipelines and non-jurisdictional gathering facilities have varied over time. While we believe the current definitions create non-jurisdictional status for our gathering facilities, no assurance is available that such facilities will not, in the future, be classified as regulated transmission facilities. If such a classification were to occur, the rates, terms and conditions of the services rendered by those facilities would become subject to regulation by the FERC.

No state in which we operate currently regulates gathering fees. Although we are not aware that any state in which we operate a natural gas gathering system is likely to begin regulation of our natural gas gathering activities and fees, new or increased state regulation has been adopted or proposed in other natural gas producing states, and there can be no assurance that such regulation will not be proposed or adopted in states where we conduct gathering activities or that we will not expand into or acquire operations in a state where such regulations could be imposed.

Canadian Pipeline Regulation

MCOC owns the Calmar system located in central Alberta, Canada. Construction, operation and reclamation of the Calmar system are primarily regulated by the Alberta Energy and Utilities Board ("EUB") and Alberta Environmental Protection. Rates for gas processing and transportation through the Calmar system are presently determined by negotiated contracts. Pursuant to the Alberta Oil and Gas Conservation Act, R.S.A. 1980, c. O-5, an application may be made to the EUB for an order declaring the Calmar system to be a common processor, purchaser and/or carrier. In the event that (i) the EUB grants such an order (with the approval of the Alberta Lieutenant Governor in Council) and (ii) an agreement respecting rates and charges cannot be reached between the applicant and MCOC, a subsequent application may then be made to the EUB to set rates and charges for gas processing, purchase and/or transportation at the Calmar system. The EUB also has the general authority pursuant to the Oil and Gas Conservation Act and Alberta Pipeline Act, R.S.C. 1980, c. P-80, to conduct an investigation into

matters and questions involving gas plants and pipelines located within Alberta, such as the Calmar system.

Environmental and Safety Matters

The Company's activities in connection with the operation and construction of pipelines and other facilities for transporting, processing, treating or storing natural gas and other products are subject to environmental and safety regulation by numerous federal, state, local and Canadian authorities. This regulation can include ongoing oversight regulation as well as requirements for construction or other permits and clearances that must be granted in connection with new projects or expansions. Regulatory requirements can increase the cost of planning, designing, initial installation and operation of such facilities. Sanctions for violation of these requirements include a variety of civil and criminal enforcement measures, including assessment of monetary penalties, assessment and remediation requirements, and injunctions as to future compliance. The following is a discussion of certain environmental and safety concerns that relate to us. It is not intended to constitute a complete discussion of the various federal, state, local and Canadian statutes, rules, regulations or orders to which our operations may be subject.

In most instances, these regulatory requirements relate to the release of substances into the environment and include measures to control water and air pollution. Moreover, we could incur liability under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, or state counterparts, regardless of our fault, in connection with the disposal or other releases of hazardous substances, including those arising out of historical operations conducted by our predecessors. Further, the recent trend in environmental legislation and regulations is toward stricter standards, and this trend will likely continue in the future.

Environmental laws and regulations may also require us to acquire a permit before we may conduct certain activities. Further, these laws and regulations may limit or prohibit activities on certain lands lying within wilderness areas, wetlands, areas providing habitat for certain species that have been identified as "endangered" or "threatened" or other protected areas. We are also subject to other federal, state and local laws covering the handling, storage or discharge of materials, and we are subject to laws that otherwise relate to the protection of the environment, safety and health. As an employer, we are required to maintain a workplace free of recognized hazards likely to cause death or serious injury and to comply with specific safety standards.

We will make expenditures in connection with environmental matters as part of our normal operations and capital expenditures. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that might become necessary. We are subject to an inherent risk of incurring environmental costs and liabilities because of our handling of oil, natural gas and petroleum products, historical industry waste disposal practices and prior use of natural gas flow meters containing mercury. There can be no assurance that we will not incur material environmental costs and liabilities. Management believes, based on our current knowledge, that we have obtained and are in current compliance with all necessary and material permits and that we are in substantial compliance with applicable material environmental and safety regulations. Further, we maintain insurance coverages that we believe are customary in the industry; however, there can be no assurance that our environmental impairment insurance will provide sufficient coverage in the event an environmental claim is made against us. See "Business and Properties--Insurance." We are not aware of any existing environmental or safety claims that would have a material impact upon our financial position or results of operations.

PIPELINE SYSTEMS

As of December 31, 1999, the Company owned an interest in and operated 81 pipelines consisting of three interstate transmission pipelines, one intrastate transmission pipeline, 35 end-user pipelines and 42 gathering pipelines. The majority of these pipelines are situated strategically in the Company's core operating areas. Certain information concerning the Company's pipelines is summarized in the following table:

PIPELINE SYSTEM (a)	DATE OF ACQUISITION OR INITIAL OPERATIONS	LOCATION	LENGTH IN MILES	AVERAGE DAILY VOLUME (b) (MMBTU/DAY)	DAILY VOLUME CAPACITY (b) (MMBTU/DAY)
TRANSMISSION PIPELINES:					
MIDLA	10/97	Monroe, LA to Baton Rouge, LA	404.6	95,850	190,000
MIT	05/97	Selmer, TN to Huntsville, AL	295.3	78,648	200,000
Kansas Pipeline	11/99	OK, KS, and MO	1,120.0	52,570	160,000
Magnolia	09/95	Central, AL	111.0	17,721	120,000
Total Transmission (4 systems)			1,930.9	244,789	670,000
END-USER PIPELINES:					
Baton Rouge	10/97	E. Baton Rouge Parish, LA	33.2	32,181	80,000
Champion	05/97	Lawerence & Colbert Cos., AL	38.0	25,000	50,000
Farmlands	10/97	Grant Parish, LA	4.3	22,059	62,000
Creole	06/98	Orleans Parish, LA	44.0	16,363	115,000
Crown Vantage	10/97	E. Baton Rouge Parish, LA	2.5	7,653	32,800
All Other (30 Systems)		TX, KS, LA, NY, TN	86.2	36,571	301,622
Total End-User (35 Systems)			208.2	139,827	641,422
GATHERING PIPELINES AND NATURAL GAS PROCESSING:					
Anadarko/Mendota(d)	08/98	OK and TX Panhandle	731.0	157,755	345,000
Calmar (d)	03/99	Calgary, CA	30.0	16,930	26,000
T33	10/97	Offshore, LA	3.9	15,315	24,000
Cook Inlet -- Oil	07/94	Cook Inlet, AK	2.7	15,026	120,000
Gloria	12/99	South, LA	133.0	8,724	75,000
All Other Systems (27 systems)(e)		AK, TX, OK, AL, MS, LA, CA	905.7	154,519	1,393,500
Total Gathering (42 systems)			1,806.3	368,269	1,983,500
Total Pipelines (81 Systems)			3,945.4	752,885	3,294,922

(a) Unless otherwise indicated, all systems are 100% owned and operated by the Company. Inactive systems owned by the Company are not included.

(b) All volume and capacity information is approximate. Average daily volumes are based on total volumes transported during the twelve-month period ended December 31, 1999, except systems that were acquired during 1999. For these systems, the average daily volumes are based on total volumes transported from the date of acquisition or initial operation through December 31, 1999.

(c) This system is owned by SeaCrest Company L.L.C., in which the Company owns a 70% interest, and is operated by the Company.

(d) These gathering systems include natural gas processing and/or treating facilities.

(e) This includes systems owned by Texana Gas Pipeline Company, in which the Company owns a 50% interest and Pan Grande Pipeline LLC, in which the Company owns a 70% interest.

OIL AND GAS PROPERTIES

The Company owned several non-operated working interests in producing and non-producing oil and natural gas properties. For the year ended December 31, 1999, revenues from the Company's oil and natural gas properties were less than 1% of its total revenues, and for the same period the Company's oil and natural gas properties represented less than 1% of its total assets.

TITLE TO PROPERTIES

The Company, as part of its pipeline construction process, must obtain certain right-of-way agreements from landowners whose property the proposed pipeline will cross. The terms and cost of these agreements can vary greatly due to a number of factors. In addition, as

part of its acquisition process, the Company will typically evaluate the underlying right-of-way agreements for the particular pipeline to be acquired to determine that the pipeline owner has met all terms and conditions of the underlying right-of-way agreements and that the agreements are still in full force and effect. The Company typically relies upon outside service organizations to review the right-of-way agreements and to make suggestions to the seller as to any curative work required before closing. The Company typically does not receive a title opinion or title policy as to these right-of-way agreements due to the complexity of the records and expense.

Occasionally, the Company may seek to initiate condemnation proceedings where permitted under state law to obtain a right-of-way necessary for pipeline construction projects. The Company believes that this process is consistent with standards in the pipeline industry and that it holds good title to its pipeline systems, subject only to defects which the Company believes are not material to the ownership of its properties or results of operations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Capital Resources and Liquidity".

INSURANCE

The Company's operations are subject to many hazards inherent in the natural gas transmission industry. The Company maintains insurance coverage for its operations and properties considered to be customary in the industry. There can be no assurance, however that the Company's insurance coverage will be available or adequate for any particular risk or loss or that the Company will be able to maintain adequate insurance in the future at rates it considers reasonable. Although management believes that the Company's assets are adequately covered by insurance, a substantial uninsured loss could have a material adverse impact on the Company's financial position, results of operations or cash flows.

EMPLOYEES AND CONTRACT SERVICE ORGANIZATIONS

The Company had 223 full-time employees on December 31, 1999. The Company also had arrangements with other unaffiliated independent pipeline operating companies to service and operate the Company's extensive field operations and provide for emergency response measures. The Company is not a party to any collective bargaining agreements. There have been no significant labor disputes in the past.

FORWARD LOOKING STATEMENTS

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Disclosure Regarding Forward Looking Statements" for a discussion of forward looking statements contained above and elsewhere in this Report.

ITEM 2. PROPERTIES.

See "Item 1. Business" for a discussion of properties and locations.

ITEM 3. LEGAL PROCEEDINGS.

The Company is currently involved in certain litigation that arose in the ordinary course of business. Except as otherwise disclosed in the KPC acquisition discussion in the "Rate and Regulatory Matters" section, management believes that all costs of settlements or judgments arising from such suits will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

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

The Company did not submit any matters during the fourth quarter to a vote of security holders.

PART II

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

MARKET INFORMATION AND DIVIDEND POLICY

The Company's Common Stock began trading August 9, 1996 on the American Stock Exchange ("AMEX") under the symbol "MRS". The following table sets forth the high and low sales prices for the Company's Common Stock for the period from January 1, 1998 to December 31, 1999.

All prices and dividends per share below, and included elsewhere in this 10-K, have been adjusted to reflect the 10% stock dividend declared on February 3, 1998 and paid on March 2, 1998 to stockholders of record on February 13, 1998, as well as the five-for-four stock split declared on February 1, 1999, and paid on March 1, 1999, to stockholders of record on February 11, 1999.

	High	Low	Dividends Paid per Share
1998			
First Quarter	$19.00	$14.72	$.058
Second Quarter	18.70	15.09	.064
Third Quarter	18.95	13.30	.064
Fourth Quarter	17.41	13.41	.064
1999			
First Quarter	$18.70	$15.50	$.064
Second Quarter	17.63	15.00	.070
Third Quarter	21.00	16.00	.070
Fourth Quarter	20.31	15.75	.070

On March 27, 2000, the closing price for the Common Stock, as reported by the AMEX, was $16.25 per share. As of March 27, 2000, there were 319 holders of record of common stock. The Company believes that there are substantially more beneficial holders of Common Stock.

On February 3, 1998, the Board declared a 10% stock dividend to be paid March 2, 1998 to stockholders of record at the close of business on February 13, 1998. No fractional shares were issued and stockholders entitled to a fractional share received a cash payment equal to the market value of the fractional share at the close of the market on the stock dividend record date.

On February 1, 1999, the Board declared a five-for-four stock split to be paid March 1, 1999 to stockholders of record at the close of business on February 11, 1999. No fractional shares were issued, and stockholders entitled to a fractional share received a cash payment equal to the market value of the fractional share at the close of the market on the stock split record date.

Holders of Common Stock are entitled to receive cash dividends out of Company funds legally available subject to the qualification that dividends need not be declared or paid by the Board if to do so would be in violation of laws or restrictions under contractual arrangements (including credit agreements) to which the Company is or may hereafter become a party.

It is the Company's current policy to continue to pay a quarterly dividend; however, the amount of future cash dividends, if any, will depend upon future earnings, results of operations, capital requirements, covenants contained in various financing agreements of the Company and its subsidiaries, the financial condition of the Company and certain other factors. Accordingly, there can be no assurances that dividends will be paid by the Company in the future. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity".

ITEM 6. SELECTED FINANCIAL DATA.

The following table sets forth, for the periods and at the dates indicated, selected historical consolidated financial data for Midcoast. This financial data has been derived from and should be read in conjunction with the consolidated financial statements of Midcoast and notes thereto included in Part II, Item 8.

	YEAR ENDED DECEMBER 31,				
	1999	1998	1997	1996	1995
	(In thousands, except per share amounts)				
STATEMENT OF OPERATIONS DATA:					
Operating revenues	$391,571	$234,069	$112,744	$29,415	$15,622
Operating income (1)	20,903	13,553	7,291	2,573	2,569
Interest expense	6,533	3,247	1,067	413	339
Income before income taxes	14,190	10,422	5,914	1,914	2,193
Net income	11,439	9,113	5,764	1,914	2,193
Net income applicable to common shareholders	11,439	9,113	5,764	1,891	2,134
PER SHARE DATA:					
Net income per share applicable to common shareholders					
Basic	$ 1.25	$ 1.29	$ 1.13	$ .73	$ 1.08
Diluted	$ 1.22	$ 1.25	$ 1.10	$ .73	$ 1.08
Weighted average number of common shares outstanding					
Basic	9,176	7,074	5,115	2,593	1,980
Diluted	9,401	7,298	5,251	2,598	1,980
Cash dividends declared per common share	$ .27	$ .25	$ .24	$ .06	$ -
OTHER DATA:					
Depreciation, depletion and amortization	$ 7,545	$ 3,197	$ 1,592	$ 818	$ 452
General and administrative	8,431	6,317	3,526	1,223	785
Cash flow from operating activities	16,699	17,169	3,856	2,564	2,361

	DECEMBER 31,				
	1999	1998	1997	1996	1995
	(In thousands)				
BALANCE SHEET DATA:					
Working capital (deficit)	$ (1,539)	$ 989	$ 1,888	$ 1,135	$ (99)
Property, plant and equipment, net	392,969	154,247	97,552	16,965	8,206
Total assets	478,372	191,342	128,038	27,303	11,089
Long-term debt, net of current portion	240,000	78,082	28,923	4,015	3,961
Shareholders' equity	160,677	66,284	61,451	13,593	4,157

(1) Operating revenues less operating expenses.

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

The following discussion of the historical financial condition and results of operations of Midcoast should be read in conjunction with "Selected Financial Data" contained in Part I, Item 6 and with the consolidated financial statements and related notes thereto contained in Part II, Item 8.

GENERAL

Since its formation, the Company has grown significantly as a result of the construction and acquisition of new pipeline facilities. For the four year period ended 1999, the Company acquired or constructed 73 pipelines for an aggregate cost of approximately $369 million. The Company believes the historical results of operations do not fully reflect the operating efficiencies and improvements that are expected to be achieved by integrating the acquired and newly constructed pipeline systems. As the Company pursues its growth strategy in the future, its financial position and results of operations may fluctuate significantly from period to period.

The Company's results of operations are determined primarily by the volumes of natural gas transported, purchased and sold through its pipeline systems or processed at its processing facilities. With the exception of the Company's natural gas processing activities, which represent a small component of the Company's overall earnings, the Company's revenues are derived from fee based sources. As a result, the Company's earnings have little sensitivity to changes in commodity prices. In addition, most of the Company's operating costs do not vary directly with volume on existing systems, thus, increases or decreases in transportation volumes generally have a direct effect on net income. The Company derives its revenues from three primary sources: (i) the marketing of natural gas and other petroleum products, (ii) transportation fees from pipeline systems owned by the Company the processing and treating of natural gas and (iii) the processing and treating of natural gas.

The Company's marketing revenues are realized through the purchase and resale of natural gas and other petroleum products to the Company's customers. Generally, gas marketing activities will generate higher revenues and correspondingly higher expenses than revenues and expenses associated with transportation activities, given the same volumes of natural gas. This relationship exists because, unlike revenues derived from transportation activities, gas marketing revenues and associated expenses include the full commodity price of the natural gas acquired. The operating income the Company recognizes from its gas marketing efforts is the difference between the price at which the natural gas was purchased and the price at which it was resold to the Company's customers. The Company's strategy is to focus its marketing activities on Company owned pipelines. The Company's marketing activities have historically varied greatly in response to market fluctuations.

Transportation fees are received by the Company for transporting natural gas or crude oil owned by other parties through the Company's pipeline systems, transport trucks and railcars. Typically, the Company incurs very little incremental operating or administrative overhead cost to transport natural gas through its pipeline assets, thereby recognizing a substantial portion of incremental transportation revenues as operating income.

The Company's natural gas processing revenues are realized from the extraction and sale of NGL's as well as the sale of the residual natural gas. These revenues occur under processing contracts with producers of natural gas utilizing both a "percentage of proceeds" and "keep-whole" basis. The contracts based on percentage of proceeds provide that the Company receives a percentage of the NGL's and residual natural gas revenues as a fee for processing the producer's gas. The keep-whole contracts require that the Company reimburse the producers for the Btu energy equivalent of the NGL's and fuel removed from the natural gas as a result of processing and the Company retains all revenues from the sale of the NGL's. The Company's processing margins can be adversely affected by declines in NGL's prices, declines in natural gas throughput, or increases in shrinkage or fuel costs, and in the case of keep-whole contracts, margins can be adversely affected affected by increases in natural gas prices.

The Company has had quarter-to-quarter fluctuations in its financial results in the past due to the fact that the Company's natural gas sales and pipeline throughputs can be affected by changes in demand for natural gas primarily because of the weather. In particular, demand on the Magnolia, MIT and MIDLA systems fluctuate due to weather variations because of the large municipal and other seasonal customers which are served by the respective systems. As a result, the winter months have historically generated more income than summer months on these systems. There can be no assurances that the Company's efforts to minimize such effects will have any impact on future quarter-to-quarter fluctuations due to changes in demand resulting from variations in weather conditions. Furthermore, future results could differ materially from historical results due to a number of factors including but not limited to interruption or cancellation of existing contracts, the impact of competitive products and services, pricing of and demand for such products and services and the presence of competitors with greater financial resources.

RESULTS OF OPERATIONS

The Company has acquired or constructed numerous pipelines in the four-year period ended December 31, 1999. The purchased assets were acquired from numerous sellers, at different periods throughout the year and all were accounted for under the purchase method of accounting

for business combinations and accordingly, the results of operations for such acquisitions are included in the Company's financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

The Company adopted the provisions of SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information, effective January 1, 1998. Accordingly, the Company has segregated its business activities into three segments: Transmission Pipelines, End-User Pipelines, and Gathering Pipelines and Natural Gas Processing.

Consolidated gross margin for the year ended December 31, 1999, increased 66% to $37.6 million compared to $22.6 million in 1998. Consolidated gross margin for the year ended December 31, 1998, was $10.6 million higher than for the same period in 1997. Variations for each segment are discussed in the segment results below.

SEGMENT RESULTS

The following tables present certain data for each of the three operating segments of the Company for the three years in the period ended December 31, 1999. As previously discussed, the Company provides marketing services to its customers. For analysis purposes, the Company accounts for the marketing services by recording the marketing activity on the operating segment where it occurs. Therefore, the gross margin for each segment includes a transportation component and a marketing component. The Company evaluates each of its segments on a gross margin basis, which is defined as the revenues of the segment less related direct costs and expenses of the segment and does not include depreciation, interest or allocated corporate overhead. For further analysis on each segment regarding identifiable assets, depreciation and corporate administrative expenses, see Note 16 - Segment Data in the Notes to Consolidated Financial Statements.

TRANSMISSION PIPELINES

	For the Year Ended December 31,		
	1999	1998	1997
	(in thousands, except amounts per MMBtu)		
OPERATING REVENUES:			
Marketing Revenue	$113,423	$111,924	$ 61,274
Transportation Fees	11,366	6,387	3,513
TOTAL OPERATING REVENUES	124,789	118,311	64,787
OPERATING EXPENSES:			
Marketing Costs	99,726	100,889	57,333
Operating Expenses	5,975	4,383	1,592
TOTAL OPERATING EXPENSES	105,701	105,272	58,925
GROSS MARGIN	$ 19,088	$ 13,039	$ 5,862
VOLUME (in MMBtu)			
Marketing	47,900	47,649	22,454
Transportation	64,503	49,506	30,752
TOTAL VOLUME	112,403	97,155	53,206
GROSS MARGIN per MMBtu	$ .17	$ .13	$ .11

Year Ended December 31, 1999 compared to Year Ended December 31, 1998

Increases in transmission segment revenues were primarily due to increased throughput volumes, increased transportation fees and the Company's acquisition of KPC in November 1999. The increase in throughput volumes was primarily from increased volumes on the MIT system and the additional volumes provided from the KPC acquisition. Increased margins per MMBtu in marketing related activities also contributed to the increase in segment earnings.

Year Ended December 31, 1998 compared to Year Ended December 31, 1997

The Company's entrance into the regulated interstate pipeline business began with the acquisition of the MIT system in June 1997 and the MIDLA system in November 1997 which significantly enhanced the Company's transmission pipeline operations in 1998. A complete year of operations in 1998 provided a 83% increase in revenues, an 83% increase in total volumes and a 122% increase in gross margin when compared to the same period in 1997. In addition to a complete year of operations, average daily demand transportation volume ("Average Demand") increased on both systems in 1998. The MIT system's Average Demand increased 19% to 158,000 MMBtu in 1998 while the MIDLA system's Average Demand increased 13% to 166,000 MMBtu in 1998

END-USER PIPELINES

	For the Year Ended December 31,		
	1999	1998	1997
	(in thousands, except amounts per MMBtu)		
OPERATING REVENUES:			
Marketing Revenue	$122,189	$96,433	$33,862
Transportation Fees	3,252	3,287	2,487
TOTAL OPERATING REVENUES	125,441	99,720	36,349
OPERATING EXPENSES:			
Marketing Costs	117,242	94,263	32,673
Operating Expenses	345	224	208
TOTAL OPERATING EXPENSES	117,587	94,487	32,881
GROSS MARGIN	$ 7,854	$ 5,233	$ 3,468
VOLUME (in MMBtu)			
Marketing	49,513	41,336	11,867
Transportation	21,151	20,415	12,415
TOTAL VOLUME	70,664	61,751	24,282
GROSS MARGIN per MMBtu	$ .11	$ .08	$ .14

Year Ended December 31, 1999 compared to Year Ended December 31, 1998

The Company's end-user segment experienced significant increases in revenues and gross margin in 1999 compared to 1998. These increases were primarily due to the addition of a high-pressure pipeline system servicing a new cogeneration facility near Baton Rouge, Louisiana and the additional earnings that were achieved through the acquisition of SIGCO in June 1999. The high pressure pipeline system was not fully optimized until the second half of 1999.

Year Ended December 31, 1998 compared to Year Ended December 31, 1997

The Company's end-user segment experienced significant increases in revenues and gross margin in 1998 compared to 1997, primarily due to 1998 having the benefit of a complete year of operations of the Champion and Monsanto systems (acquired in the MIT Acquisition in June 1997) and Crown Vantage and Farmlands systems (acquired in the MIDLA Acquisition in November 1997). A new marketing services contract to provide 25 MMcf/day of marketing services beginning January 1, 1998 to an industrial facility near Port Hudson, Louisiana also contributed to the increase in 1998 over 1997.

The Company's gross margin per MMBtu declined in 1998 as compared to 1997. The decrease was attributable to an increase in marketing activities, which are characterized by lower margins and higher volumes.

GATHERING PIPELINES AND NATURAL GAS PROCESSING

	For the Year Ended December 31,		
	1999	1998	1997
	(in thousands, except amounts per MMBtu)		
OPERATING REVENUES:			
Marketing Revenue	$110,064	$ 6,761	$ 5,597
Transportation Fees	12,039	3,732	693
Processing and Treating Revenue	16,844	5,107	4,956
TOTAL OPERATING REVENUES	138,947	15,600	11,246
OPERATING EXPENSES:			
Marketing Costs	104,528	4,781	4,548
Operating Expenses	11,263	2,410	415
Processing and Treating Costs	12,450	4,052	3,566
TOTAL OPERATING EXPENSES	128,241	11,243	8,529
GROSS MARGIN	$ 10,706	$ 4,357	$ 2,717
VOLUME (in MMBtu)			
Marketing	30,918	4,326	2,170
Transportation	96,567	48,136	13,603
Processing and Treating	11,552	2,544	1,850
TOTAL VOLUME	139,037	55,006	17,623
GROSS MARGIN per MMBtu	$ .08	$ .08	$ .15

Year Ended December 31, 1999 compared to Year Ended December 31, 1998

The Company's gathering and processing segment experienced significant increases in revenues and gross margins in 1999 compared to 1998. These increases were mostly attributable to a full year of Anadarko system earnings and the Seacrest, Calmar and DPI/Flare acquisitions in March 1999. Although marketing revenues increased over 1,500%, overall marketing margins increased approximately 180% due to DPI's higher volume but lower margin marketing business.

Year Ended December 31, 1998 compared to Year Ended December 31, 1997

Revenues, gross margins and volumes increased substantially in 1998 compared to 1997 in the Gathering Pipelines and Natural Gas Processing business segment.

The significant increase in gathering activity in 1998 was attributable to the Anadarko Acquisition that was effective in August 1998. Although the Company's 1998 operations only included five months of activity from the Anadarko system, it was responsible for 50% of the volumes gathered and approximately $1 million of the gross margin earned in 1998.

Despite a 38% increase in the volume of natural gas processed through its processing facilities, the Company's gross margin from processing activities declined significantly in 1998 as compared to 1997. This decline was due to lower processing spreads realized in 1998 as NGL commodity prices continued to deteriorate throughout the year. The increase in processing volumes in 1998 was attributable to the acquisition of the Hobart processing plant in the Anadarko Acquisition in August 1998.

Marketing volumes increased 99% in 1998 over 1997. These volumetric increases were the result of various acquisitions. Collectively, two acquisitions accounted for 90% of the increase.

OTHER INCOME, COSTS AND EXPENSES

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Other revenues for the year ended December 31, 1999 increased to $2.4 million from $0.4 million in 1998. The increase was primarily attributable to income earned by Flare on processing and treating plant construction projects.

Depreciation, depletion and amortization for the year ended December 31, 1999 increased to $7.5 million from $3.2 million in 1998. This increase was primarily due to increased depreciation on assets acquired in the KPC, Anadarko, DPI/Flare and Calmar acquisitions.

General and administrative expenses for the year ended December 31, 1999 increased to $8.4 million from $6.3 million in 1998. The increase was due to increased costs associated with the management of the assets acquired in the KPC, Anadarko, DPI/Flare and Calmar acquisitions. General and administrative expenses, as a percentage of gross margin, decreased 6% from 28% in 1998 to 22% in 1999.

Interest expense for the year ended December 31, 1999 increased to $6.5 million, from $3.2 million in 1998. The Company was servicing an average of $110.5 million in debt for the year ended December 31, 1999 as compared to $45.6 million in debt for the year ended December 31, 1998. The increased debt level in 1999 was primarily associated with the debt used to finance the Company's KPC acquisition in November 1999 as well as its DPI/Flare and Calmar acquisitions in March 1999. The additional expense related to increased debt levels was mitigated by a reduction in the Company's weighted average interest rate. The Company's weighted average interest rate was 6.37% and 7.11% for the years ended December 31, 1999 and 1998, respectively.

During the fourth quarter of fiscal 1999, the Company recorded a pre-tax unusual charge totaling $2.7 million ($2.2 million after tax) related to the streamlining efforts announced in November 1999. The charge primarily relates to the severance and benefits of approximately 50 employees who were involuntary terminated. The Company anticipates savings from reduced employee cost and more streamlined operating and business processes. At December 31, 1999, an accrued liability of $1.8 million related to the severance charges was included in "Accounts payable and accrued liabilities" on the consolidated balance sheet. Thirty-three of these employees were still employed with the Company at December 31, 1999. The final severance will be paid in April 2002.

The Company had an extraordinary charge of $0.6 million for the year ended December 31, 1999 incurred in connection with the write-down of deferred financing charges as a result of amending the Company's credit facility.

Operating income, excluding the unusual charge, for the year ended December 31, 1999 increased to $23.6 million from $13.6 million in 1998.

Year Ended December 31, 1998 Compared to Year Ended December 31, 1997

In 1998, the Company received revenues of $0.4 million from its oil and natural gas properties as compared to $0.3 million over the same period in 1997. The increase was primarily attributable to a one-time settlement received by the Company on its Vealmoor Field properties.

In 1998, the Company's depreciation, depletion and amortization increased when compared to 1997 primarily due to increased depreciation on assets acquired in the MIT, MIDLA and Anadarko Acquisitions. Collectively, these acquisitions accounted for 105% of the increase of $1.6 million.

The Company's general and administrative expenses in 1998 increased $2.8 million when compared to 1997 primarily due to the numerous acquisitions the Company made during 1997 and 1998. In addition, the increase was attributed to the Company's expansion of its infrastructure to allow for continued growth.

Interest expense for the year ended December 31, 1998 increased to $3.2 million, from $1.1 million in 1997. The Company was servicing an average of $45.6 million in debt for the year ended December 31, 1998 as compared to $13.6 million in debt for the year ended December 31, 1997. The increased debt load in 1998 was primarily associated with the debt used to finance the MIDLA Acquisition being outstanding for a full year as compared to only two months in 1997. In addition, $35 million of additional debt associated with the Anadarko Acquisition was outstanding for four months in 1998. The additional expense related to increased debt levels was mitigated by a reduction in

the Company's weighted average interest rate. The Company's weighted average interest rate was 7.11% and 7.83% for the years ended December 31, 1998 and 1997, respectively.

The Company recognized annual operating income and net income in 1998 of $13.6 million and $9.1 million, respectively, as compared to $7.3 million in operating income and $5.8 million in net income for the year ended 1997. EPS increased 14% from $1.10 in 1997 to $1.25 in 1998. The significant improvement in EPS is primarily attributable to the positive impact of accretive acquisitions consummated during 1998 and 1997.

INCOME TAXES

As of December 31, 1999, the Company has NOL carryforwards of approximately $10.3 million, expiring in various amounts from 2003 through 2018. These loss carryforwards were generated by companies acquired by Midcoast. The ability of the Company to utilize the carryforwards is dependent upon the Company generating sufficient taxable income and will be affected by annual limitations (currently estimated at $5.2 million) on the use of such carryforwards due to a change in shareholder control under section 382 of the Internal Revenue Code triggered by the Company's July 1997 Common Stock offering and the change of ownership created by the acquisition of Republic and DPI.

The valuation allowance declined $2.1 million during the year ended December 31, 1999. The decline was the net result of current year utilization of net operating losses to offset taxable income and the removal of $581,000 of valuation allowance related to net operating losses that are more likely than not to be utilized in the future.

CAPITAL RESOURCES AND LIQUIDITY

Since 1996, the Company has acquired approximately $368.9 million of pipeline systems. Capital requirements have been funded through equity infusions from common stock offerings, borrowings from various commercial banks and cash flow from operations.

The Company has raised net proceeds of approximately $128 million in four common stock offerings since being listed on the American Stock Exchange in August 1996. These capital infusions and the stability of our cash flow has allowed the Company the financial flexibility to utilize lower cost conventional bank debt financing to fund a large part of its growth. The Company's long-term debt to total capitalization ratio increased from 54% at December 31, 1998 to 60% at December 31, 1999.

In November 1999 and again in March 2000, the Company amended and restated its bank financing agreement under the certain Amended and Restated Credit Agreement dated August 31, 1998. The amendments added additional banks to the syndicate, increased our borrowing availability, modified our letter of credit facility, extended the maturity five years to November 2004, modified financial covenants, established waiver and amendment approvals and changed the method to determine the interest rate to be charged.

The amendments to the credit agreement increased our borrowing availability from $125 million to $335 million, with a provision to increase up to $400 million. The amended credit agreement provides borrowing availability as follows: (i) up to a $25 million sublimit for the issuance of standby and commercial letters of credit and (ii) the difference between the $335 million and the used sublimit available as a revolving credit facility. At the option of the Company, borrowings under the amended credit agreement accrue interest at LIBOR plus an applicable margin or the higher of the Bank of America prime rate or the Federal Funds rate plus an applicable margin.

The applicable margin percentage to be added to the interest rate is based on the Company's debt to total capitalization ratio at the end of each fiscal quarter. The Company is charged a margin between 1.0% and 2.0% as the Company's total debt to total capitalization ratio ranges from under 40% and over 65%, respectively. The Company's borrowings are currently being charged at the margin of 1.75%. The Company was also subject to an arrangement fee, agency fee, underwriting fee, unused fee and commitment fee totaling $1.2 million. Additionally, the Company is subject to an annual administrative agency fee of $35,000.

The credit agreement is secured by all accounts receivable, contracts, and the pledge of all of our subsidiaries' stock and a first lien security interest in our pipeline systems. It also contains a number of customary covenants that require us to maintain certain financial ratios and limit our ability to incur additional indebtedness, transfer or sell assets, create liens, or enter into a merger or consolidation. The Company is required to comply with more stringent debt to capitalization and EBITDA to interest ratios by June 30, 2000. Subsequent to the amendment in March 2000, the Company has approximately $73 million of available capacity under its credit agreement.

For the year ended December 31, 1999, the Company generated cash flow from operating activities of approximately $16.7 million.

Currently, the Company has committed to making approximately $4.9 million in construction related expenditures in 2000. The Company believes that its credit agreement and funds provided by operations will be sufficient to meet its operating cash needs for the foreseeable future and its projected capital expenditures, other than acquisitions.

If sufficient funds under the credit agreement are not available to fund acquisition and construction projects, the Company would seek to obtain such financing from the sale of equity securities or other debt financing. There can be no assurances that any such financing will be available on terms acceptable to the Company. Should sufficient capital not be available, the Company will not be able to implement its growth strategy in as aggressive a manner as currently planned.

RECENT ACCOUNTING PRONOUNCEMENT

The FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". This Statement establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, (collectively referred to as derivatives) and for hedging activities. SFAS No. 133 will require the Company to record all derivatives on the balance sheet at fair value. Changes in derivative fair values will either be recognized in earnings as offsets to the changes in fair value of related hedged assets, liabilities and firm commitments or, for forecasted transactions, deferred and recorded as a component of other shareholders' equity until the hedged transactions occur and are recognized in earnings. The ineffective portion of a hedging derivative's change in fair value will be immediately recognized in earnings. The impact of SFAS No. 133 on the Company's financial statements will depend on a variety of factors, including future interpretative guidance from the FASB, the extent of the Company's hedging activities, the types of hedging instruments used and the effectiveness of such instruments. The standard was amended by SFAS No. 137 in June 1999. The amendment defers the effective date of SFAS No. 133 to fiscal years beginning after June 15, 2000. The Company is currently evaluating the effects of this pronouncement.

ENVIRONMENTAL AND SAFETY MATTERS

Our activities in connection with the operation and construction of pipelines and other facilities for transporting, processing, treating, or storing natural gas and other products are subject to environmental and safety regulation by numerous federal, state, local and Canadian authorities. This regulation can include ongoing oversight regulation as well as requirements for construction or other permits and clearances that must be granted in connection with new projects or expansions. Regulatory requirements can increase the cost of planning, designing, initial installation and operation of such facilities. Sanctions for violation of these requirements include a variety of civil and criminal enforcement measures, including assessment of monetary penalties, assessment and remediation requirements and injunctions as to future compliance. The following is a discussion of certain environmental and safety concerns that relate to us. It is not intended to constitute a complete discussion of the various federal, state, local and Canadian statutes, rules, regulations, or orders to which our operations may be subject.

In most instances, these regulatory requirements relate to the release of substances into the environment and include measures to control water and air pollution. Moreover, we could incur liability under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, or state counterparts, regardless of our fault, in connection with the disposal or other releases of hazardous substances, including those arising out of historical operations conducted by our predecessors. Further, the recent trend in environmental legislation and regulations is toward stricter standards, and this trend will likely continue in the future.

Environmental laws and regulations may also require us to acquire a permit before we may conduct certain activities. Further, these laws and regulations may limit or prohibit activities on certain lands lying within wilderness areas, wetlands, areas providing habitat for certain species that have been identified as "endangered" or "threatened" or other protected areas. We are also subject to other federal, state and local laws covering the handling, storage or discharge of materials, and we are subject to laws that otherwise relate to the protection of the environment, safety and health. As an employer, we are required to maintain a workplace free of recognized hazards likely to cause death or serious injury and to comply with specific safety standards.

We will make expenditures in connection with environmental matters as part of our normal operations and capital expenditures. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that might become necessary. We are subject to an inherent risk of incurring environmental costs and liabilities because of our handling of oil, gas and petroleum products, historical industry waste disposal practices and prior use of gas flow meters containing mercury. There can be no assurance that we will not incur material environmental costs and liabilities. Management believes, based on our current knowledge, that we have obtained and are in current compliance with all necessary and material permits and that we are in substantial compliance with applicable material environmental and safety regulations. Further, we maintain insurance coverages that we

believe are customary in the industry; however, there can be no assurance that our environmental impairment insurance will provide sufficient coverage in the event an environmental claim is made against us. See "Business and Properties--Insurance." We are not aware of any existing environmental or safety claims that would have a material impact upon our financial position or results of operations.

YEAR 2000

The Company completed all phases of the Year 2000 Program relative to computer systems and technology infrastructure considered essential to the Company's business prior to the event. The year 2000 event passed without significant incident. The Company's contingency plans are designed to minimize any disruptions or other adverse effects resulting from unexpected incompatibilities regarding core systems and business applications and to facilitate the early identification and remediation of system problems that manifest themselves after December 31, 1999. To date, no significant items have been identified. The Company continues to assess, test and remediate business application and technology infrastructure that were previously determined to be other than essential to core business operations. The extent of these activities is very insignificant to the Company's overall business. Aggregate costs expended for the Year 2000 Project totaled approximately $1.0 million.

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

This Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in and incorporated by reference into this Form 10-K are forward-looking statements. These forward looking statements include, without limitation, statements under "Management's Discussion and Analysis of Financial Condition and Results of Operations--Capital Resources and Liquidity" regarding the Company's estimate of the sufficiency of existing capital resources, whether funds provided by operations will be insufficient to meet its operational needs in the foreseeable future, and its ability to use NOL carryforwards prior to their expiration. Although, we believe that the expectations reflected in these forward looking statements are reasonable, we can not give any assurance that such expectations reflected in these forward looking statements will prove to have been correct.

When used in this Form 10-K, the words "expect", "anticipate", "intend", "plan", "believe", "seek", "estimate", and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations", and elsewhere in this Form 10-K.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. Before you invest in our common stock, you should be aware that the occurrence of any of the events described in "Risk Factors" in the Prospectus Supplement, dated December 6, 1999 and elsewhere in this Form 10-K could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common stock could decline, and you could lose all or part of your investment.

We cannot guarantee any future results, levels of activity, performance or achievements. Except as required by law, we undertake no obligation to update any of the forward-looking statements in this Form 10-K after the date of this Form 10-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

The Company utilizes derivative financial instruments to manage market risks associated with certain energy commodities and interest rates. According to guidelines provided by the Board, the Company enters into exchange-traded commodity futures, options and swap contracts to reduce the exposure to market fluctuations in the price of energy commodities and fluctuations in interest rates. The Company does not engage in speculative trading. Approvals are required from senior management prior to the execution of any financial derivative.

COMMODITY PRICE RISK

The Company's commodity price risk exposure arises from inventory balances and fixed price purchase and sale commitments. The Company uses exchange-traded commodity futures contracts, options and swap contracts to manage and hedge price risk related to these market exposures. These futures and options contracts have pricing terms indexed to the NYMEX.

Gas futures involve the buying and selling of natural gas at a fixed price. Over-the-counter swap agreements require the Company to receive or make payments based on the difference between a specified price and the actual price of natural gas. The Company uses futures and swaps to manage margins on offsetting fixed-price purchase or sales commitments for physical quantities of natural gas. Options provide the right, but not the obligation, to buy or sell energy commodities at a fixed price. The Company utilizes options to manage margins and to limit overall price risk exposure. (See Note 11 - Financial Instruments and Price Risk Management Activities in the Notes to Consolidated Financial Statements). As of December 31, 1999 and 1998, the Company had net unrealized losses on its various open commodity futures, swaps and option contracts of $1,139,000 and $896,000, respectively. The tabular presentation related to the Company's commodity price risk is illustrated below (in thousands, except for price per MMBtu amounts):

	As of December 31, 1999 Expected Fiscal Year of Maturity	
	2000	Fair Value
Swap Contracts:		
Contract Volumes (MMBtu)	5,045	-
Weighted Average Price (Per MMBtu)	$ 2.11	$ -
Contract Amount	$10,635	$9,608
Futures Contracts:		
Contract Volumes (MMBtu)	930	-
Weighted Average Price (Per MMBtu)	$ 2.47	$ -
Contract Amount	$ 2,295	$2,183

INTEREST RATE RISK

The Company's debt financial instruments are sensitive to market fluctuations in interest rates. The interest rate swap agreements entered into by the Company effectively convert $65 million of floating-rate debt to fixed-rate debt (see Note 11 - Financial Instruments and Price Risk Management Activities in the Notes to Consolidated Financial Statements). The Company makes payments to counterparties at fixed rates and in return receives payments at floating rates. The first swap agreement, which has a notional amount of $25 million, was entered into in December 1997. It was subsequently transferred to another bank in November 1998 and replaced with a new swap agreement which has an initial term of two years through December 2000 but is extendible, at the bank's option, for an additional three years. The second swap agreement, with a notional amount of $40 million, was entered into in October 1998 and has an initial term of three years through November 2001 but is extendible, at the bank's option, for an additional two years. Both transactions are recorded using accrual accounting. The table below presents notional amounts and weighted average interest rates by expected or contractual maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. The tabular presentation related to the Company's interest rate risk is illustrated below (in thousands, except for interest rates):

	As of December 31, 1999 Expected Fiscal Year of Maturity						
	2000	2001	2002	2003	2004	Total	Fair Value
Liabilities:							
Long-term debt, including current portion - variable interest rate of 8.17% at December 31, 1999	$ 71	-	-	-	$240,000	$240,071	$240,071
Interest Rate Derivatives:							
Interest rate swaps, variable to fixed rate - notional amounts	$25,000	$40,000	-	-	-	$ 65,000	$ 976
Average interest rate	4.71%	4.48%					
Average received rate	6.58%	6.99%					
Net cash flow effect	$ 1,211	$ 1,007					

ITEM 8. FINANCIAL STATEMENTS.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders
of Midcoast Energy Resources, Inc.:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, comprehensive income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Midcoast Energy Resources, Inc. and its subsidiaries at December 31, 1999 and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for the opinion expressed above.

PRICEWATERHOUSECOOPERS LLP

Houston, Texas
March 10, 2000

INDEPENDENT AUDITOR'S REPORT

Board of Directors and Shareholders
Midcoast Energy Resources, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheet of Midcoast Energy Resources, Inc. and subsidiaries as of December 31, 1998, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the two year period ended December 31, 1998. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Midcoast Energy Resources, Inc., and subsidiaries as of December 31, 1998, and the results of their operations and their cash flows for each of the years in the two year period ended December 31, 1998, in conformity with generally accepted accounting principles.

HEIN + ASSOCIATES LLP

Houston, Texas
March 18, 1999

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 1999	December 31, 1998
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,345	$ 200
Accounts and notes receivable, net of allowance of $1,484 and $92, respectively	55,189	33,020
Other current assets	4,905	1,363
Total Current Assets	62,439	34,583
Property, Plant and Equipment, net	392,969	154,247
Other Assets	22,964	2,512
Total Assets	$478,372	$191,342
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 63,901	$ 32,540
Current portion of long-term debt	71	930
Other current liabilities	6	124
Total Current Liabilities	63,978	33,594
Long-term Debt	240,000	78,082
Other Liabilities	2,147	2,024
Deferred Income Taxes	11,034	10,808
Commitments and Contingencies	-	-
Minority Interest in Consolidated Subsidiaries	536	550
Shareholders' Equity:		
Common stock, par value $.01 per share; authorized 31,250,000 shares; issued 12,721,980 and 7,149,513 shares, respectively	127	71
Paid-in capital	165,964	80,955
Accumulated deficit	(2,915)	(11,947)
Unearned compensation	-	(4)
Accumulated other comprehensive income	71	-
Treasury stock (at cost), 161,156 and 181,125 treasury shares, respectively	(2,570)	(2,791)
Total Shareholders' Equity	160,677	66,284
Total Liabilities and Shareholders' Equity	$478,372	$191,342

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

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share and share data)

	For the Year Ended December 31,		
	1999	1998	1997
Operating Revenues:			
Energy marketing revenue	$ 345,676	$ 215,118	$ 100,733
Transportation fees	26,657	13,406	6,693
Natural gas processing and treating revenue	16,844	5,107	4,956
Other	2,394	438	362
Total operating revenues	391,571	234,069	112,744
Operating Expenses:			
Energy marketing expenses	339,079	206,950	96,769
Natural gas processing and treating costs	12,450	4,052	3,566
Other operating expenses	478	-	-
Depreciation, depletion and amortization	7,545	3,197	1,592
General and administrative	8,431	6,317	3,526
Unusual charge	2,685	-	-
Total operating expenses	370,668	220,516	105,453
Operating income	20,903	13,553	7,291
Non-Operating Items:			
Interest expense	(6,533)	(3,247)	(1,067)
Minority interest in consolidated subsidiaries	(43)	(58)	(222)
Other income (expense), net	(137)	174	(88)
Total non-operating items	(6,713)	(3,131)	(1,377)
Income before income taxes and extraordinary item	14,190	10,422	5,914
Provision for income taxes:			
Current	(1,833)	(114)	(150)
Deferred	(336)	(1,195)	-
Income before extraordinary item	12,021	9,113	5,764
Extraordinary item, net of income tax provision of $300	(582)	-	-
Net Income	$ 11,439	$ 9,113	$ 5,764
Earnings per common share:			
Basic			
Income before extraordinary item	$ 1.31	$1.29	$ 1.13
Extraordinary Item	(.06)	-	-
Net Income	$ 1.25	$1.29	$ 1.13
Diluted			
Income before extraordinary item	$ 1.28	$1.25	$ 1.10
Extraordinary Item	(.06)	-	-
Net Income	$ 1.22	$1.25	$ 1.10
Weighted Average Number of Common Shares Outstanding:			
Basic	9,176,201	7,074,372	5,115,169
Diluted	9,400,754	7,298,345	5,251,456

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

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Year Ended December 31,		
	1999	1998	1997
Net income	$11,439	$9,113	$5,764
Foreign currency translation adjustment	71	-	-
Comprehensive income	$11,510	$9,113	$5,764

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

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In thousands, except per share data)

	Common Stock		Paid-in Capital	Accumulated Deficit	Unearned Compensation	Accumulated Other Comprehensive Income	Treasury Stock		Total Shareholders' Equity
	Shares	Amount					Shares	Amount	
BALANCE, DECEMBER 31, 1996	3,130	$ 32	$ 26,935	$(13,284)	$(90)	$ -	-	$ -	$ 13,593
Net Income	-	-	-	5,764	-	-	-	-	5,764
Shares issued or vested under various stock-based compensation arrangements	-	-	-	-	72	-	-	-	72
10% Stock Dividend (645 shares)	645	6	10,555	(10,565)	-	-	-	-	(4)
Sale of 2,894 shares of common stock	2,894	29	34,024	-	-	-	-	-	34,053
Common stock warrants issued in conjunction with the MIDLA Acquisition	481	4	9,167	-	-	-	-	-	9,171
Common Stock Dividends, $.24 per share	-	-	-	(1,198)	-	-	-	-	(1,198)
BALANCE, DECEMBER 31, 1997	7,150	$ 71	$ 80,681	$(19,283)	$(18)	$ -	-	$ -	$ 61,451
Net Income	-	-	-	9,113	-	-	-	-	9,113
Shares issued or vested under various stock-based compensation arrangements	-	-	-	-	14	-	-	-	14
Warrants Exercised	-	-	274	-	-	-	-	-	274
Treasury Stock Purchased (181 shares)	-	-	-	-	-	-	(181)	(2,791)	(2,791)
Common Stock Dividends, $.25 per share	-	-	-	(1,777)	-	-	-	-	(1,777)
BALANCE, DECEMBER 31, 1998	7,150	$ 71	$ 80,955	$(11,947)	$ (4)	$ -	(181)	$(2,791)	$ 66,284
Net Income	-	-	-	11,439	-	-	-	-	11,439
Shares issued or vested under various stock-based compensation arrangements	-	-	-	-	4	-	-	-	4
Stock options exercised	-	-	42	-	-	-	-	-	42
Sale of 3,572 shares of common stock	3,572	36	54,547	-	-	-	-	-	54,583
Sale of 2,000 shares of common stock	2,000	20	30,225	-	-	-	-	-	30,245
Treasury Stock Purchased (144 shares)	-	-	-	-	-	-	(144)	(2,406)	(2,406)
Treasury Stock issued in connection with the DPI Acquisition (164 shares)	-	-	195	-	-	-	164	2,627	2,822
Foreign currency translation adjustment	-	-	-	-	-	71	-	-	71
Common Stock Dividends, $.27 per share	-	-	-	(2,407)	-	-	-	-	(2,407)
BALANCE, DECEMBER 31, 1999	12,722	$127	$165,964	$ (2,915)	$ -	$71	(161)	$(2,570)	$160,677

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

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Year Ended December 31,		
	1999	1998	1997
Cash Flows from Operating Activities:			
Net income	$ 11,439	$ 9,113	$ 5,764
Adjustments to arrive at net cash provided by operating activities -			
Depreciation, depletion and amortization	7,545	3,197	1,592
Deferred income taxes	336	1,195	-
Recognition of deferred income	(76)	(83)	(83)
Minority interest in consolidated subsidiaries	43	58	222
Extraordinary charge, net of tax	582	-	-
Other	(96)	-	69
Changes in working capital accounts:			
Increase in accounts receivable	(11,396)	(4,498)	(12,022)
Increase in other current assets	186	(138)	(933)
Increase in accounts payable and accrued liabilities	8,136	8,325	9,247
Net cash provided by operating activities	16,699	17,169	3,856
Cash Flows from Investing Activities:			
Acquisitions, net of cash acquired	(238,104)	(52,076)	(60,778)
Capital expenditures	(16,562)	(7,816)	(1,410)
Net receipts from (advances to) equity investee	368	(724)	-
Other	-	(695)	(309)
Net cash used by investing activities	(254,298)	(61,311)	(62,497)
Cash Flows from Financing Activities:			
Bank debt borrowings	194,658	89,159	65,321
Bank debt repayments	(33,599)	(39,969)	(39,891)
Net proceeds from equity offerings	84,870	-	34,053
Financing costs	(1,372)	(588)	(504)
Treasury stock purchases	(2,406)	(2,791)	-
Dividends on common stock	(2,407)	(1,777)	(1,198)
Net cash provided by financing activities	239,744	44,034	57,781
Net Increase (Decrease) in Cash and Cash Equivalents	2,145	(108)	(860)
Cash and Cash Equivalents, beginning of year	200	308	1,168
Cash and Cash Equivalents, end of year	$ 2,345	$ 200	$ 308
Supplemental Disclosures:			
Cash Paid for Interest	$ 7,357	$ 2,135	$ 706
Cash Paid for Income Taxes	$ 460	$ 311	$ 241

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

1. ORGANIZATION AND BUSINESS:

The Company was formed on May 11, 1992, as a Nevada corporation and in September 1992, through a merger accounted for as a pooling of interest, became the successor to Nugget Oil Corporation. The Company was reincorporated as a Texas corporation in 1999.

The Company is primarily engaged in the transportation, gathering, processing and marketing of natural gas and other petroleum products. As of December 31, 1999, the Company owned and operated three interstate transmission pipeline systems, one intrastate transmission system, 35 end-user systems and 42 gathering systems representing approximately 4,000 miles of pipeline with an aggregate daily throughput capacity of over 3.0 Bcf of natural gas per day. Operations also included natural gas processing and treating facilities and over 80 natural gas liquid and crude oil tanks and rail cars. The Company's principal business consisted of providing transportation services to both end-users and natural gas producers, providing natural gas marketing services to these customers and processing natural gas. In connection with these services, the Company acquires and constructs pipelines to meet customer needs. The Company's principal assets are located in the Gulf Coast and Mid-Continent areas.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries of the Company after the elimination of all significant intercompany accounts and transactions. The equity method of accounting is used for investments in affiliates where the Company owns fifty percent or less and is not deemed to have significant control. The financial statements for previous periods include certain reclassifications that were made to conform to the current year presentation. Such reclassifications have no impact on reported net income or shareholders' equity.

Use of Estimates

The preparation of the Company's consolidated financial statements in conformity with generally accepted accounting principles requires the Company's management to make estimates and assumptions that effect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Actual results could differ from those estimates.

Cash and Cash Equivalents

The Company considers short-term, highly liquid investments that have an original maturity of three months or less at the time of purchase to be cash equivalents.

Gas Imbalances

In the course of providing services to customers, natural gas pipelines may receive different quantities of gas from shippers than the quantities delivered on behalf of those shippers. These transactions result in natural gas imbalance receivables and payables that are settled through cash-out procedures specified in each tariff or recovered or repaid through the receipt or delivery of gas in the future. Such imbalances are recorded as current assets or current liabilities on the balance sheet using the posted index prices of the applicable FERC-approved tariffs, which approximate market rates. Natural gas imbalances were not material as of December 31, 1999 and 1998.

Inventories

Inventories consist primarily of materials and supplies, natural gas and liquid petroleum products. Inventories of materials and supplies utilized for ongoing replacements and expansions are carried at average cost and are reviewed regularly and adjusted to their net realizable value. The natural gas and liquid petroleum products are carried at fair value, which approximates average cost. Inventories are included in "Other Current Assets" on the consolidated balance sheets.

Regulated Pipelines

MIT, MLGC and KPC are subject to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation."

Regulatory assets represent probable future revenue to MIT, MLGC and KPC associated with certain costs which will be recovered from customers through the regulatory, or the rate making process. Regulatory assets are included in "Other Assets" on the consolidated balances sheets.

The FERC regulates the interstate transportation and certain sales of natural gas, including among other things, rates and charges allowed natural gas companies, extensions and abandonment of facilities and service, rates of depreciation and amortization and certain accounting methods utilized by MIT, MLGC and KPC.

Property, Plant and Equipment

Interstate and intrastate natural gas transmission, distribution and processing facilities and other equipment are stated at cost and depreciated by the straight-line method at rates based on the following estimated useful lives of the assets:

Interstate natural gas transmission facilities	15 - 66	Years
Intrastate natural gas transmission facilities	15 - 60	Years
Pipeline right-of-ways	17	Years
Natural gas processing facilities	30	Years
Other property and equipment	3 - 10	Years

For regulated interstate natural gas transmission facilities, the cost of additions to property, plant and equipment includes direct labor and material, allocable overheads and an allowance for the estimated cost of funds used during construction ("AFUDC"). Such provisions for AFUDC are not reflected separately in the accompanying consolidated statements of operations due to the amounts not being material. Maintenance and repairs, including the cost of renewals of minor items of property, are charged principally to expense as incurred. Major additions, replacements and improvements of property (exclusive of minor items or property) are charged to the appropriate property accounts. Upon retirement of a pipeline plant asset, its cost is charged to accumulated depreciation together with the cost of removal, less salvage value.

For all other non-regulated assets, repairs and maintenance are charged to expense as incurred; renewals and betterments are capitalized including any direct labor.

The Company accounts for its oil and gas production activities using the full cost method of accounting. Under this method of accounting, all costs, including indirect costs related to exploration and development activities, are capitalized as oil and gas property costs. No gains or losses are recognized on the sale or disposition of oil and gas reserves, except for sales that include a significant portion of the total remaining reserves.

Impairment of Long-Lived Assets

In accordance with FASB Statement No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," the Company recognizes impairment losses for long-lived assets used in operations when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. During the first quarter of 1999, the Company wrote down, by approximately $145,000, a certain pipeline system to salvage value. The amount is included in "Depreciation, depletion and amortization" in the Consolidated Statement of Operations.

Goodwill

Goodwill, representing the excess cost of purchased subsidiaries over the fair value of net assets acquired, is amortized using the straight-line method over 20 years.

Treasury Stock

Treasury stock is accounted for using the cost method and is shown as a reduction to shareholders' equity in the consolidated balance sheets. Treasury stock sold or issued is valued on a weighted average basis.

Employee Stock Based Compensation

In 1997, the Company adopted FASB Statement No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123"). Under SFAS 123, the Company is permitted to either record expenses for stock options and other stock-based employee compensation plans

based on their fair value at the date of grant or to continue to apply Accounting Principles Board Opinion No. 25 ("APB 25") and recognize compensation expense, if any, based on the intrinsic value of the equity instrument at the measurement date. The Company elected to continue following APB 25; therefore, no compensation expense has been recognized because the exercise price of employee stock options equals the market price of the underlying stock on the date of grant.

Revenue Recognition

Customers are invoiced and the related revenue is recorded as natural gas and other petroleum products are delivered. Oil and natural gas revenue from the Company's interests in producing wells is recognized as oil and natural gas is produced from those wells. Revenue from renovated and manufactured equipment sales is recognized at the time of sale.

Income Taxes

Income taxes are based on income reported for tax return purposes along with a provision for deferred income taxes. Deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax bases of assets and liabilities at each year-end. Tax credits are accounted for under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. Deferred tax assets are reduced by a valuation allowance when, based upon management's estimates, it is more likely than not that a portion of the deferred tax asset will not be realized in a future period. The estimates utilized in the recognition of deferred tax assets are subject to revision in future periods based on new facts or circumstances.

Hedging Activities

It is the Company's policy to maintain as nearly as practicable a fully hedged position on its net natural gas purchase and sales commitments using back-to-back physical transactions. When a back-to-back physical transaction cannot be completed, the Company will periodically enter into financial instruments to reduce its exposure to commodity price risk. The Company uses futures and options with maturities of eighteen months or less to hedge against the volatility of the price of natural gas purchases and sales. The financial derivatives have pricing terms indexed to the NYMEX futures contract. Gains or losses on hedging activities are deferred until the physical transaction occurs. Gains or losses relating to financial derivatives terminated prior to maturity are recognized currently in income. See "Note 11. Financial Instruments and Price Risk Management Activities" for information on unrealized losses, notional amounts and notional contracts at December 31, 1999.

Recent Accounting Pronouncement

The FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". This Statement establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, (collectively referred to as derivatives) and for hedging activities. SFAS No. 133 will require the Company to record all derivatives on the balance sheet at fair value. Changes in derivative fair values will either be recognized in earnings as offsets to the changes in fair value of related hedged assets, liabilities and firm commitments or, for forecasted transactions, deferred and recorded as a component of other shareholders' equity until the hedged transactions occur and are recognized in earnings. The ineffective portion of a hedging derivative's change in fair value will be immediately recognized in earnings. The impact of SFAS 133 on the Company's financial statements will depend on a variety of factors, including future interpretative guidance from the FASB, the extent of the Company's hedging activities, the types of hedging instruments used and the effectiveness of such instruments. The standard was amended by SFAS No. 137 in June 1999. The amendment defers the effective date of SFAS No. 133 to fiscal years beginning after June 15, 2000. The Company is currently evaluating the effects of this pronouncement.

3. ACQUISITIONS

The MIT Acquisition

In May 1997, the Company acquired the pipeline and energy services operations from Atrion Corporation for cash consideration of $38.2 million and up to $2 million in contingent deferred payments. The MIT operations include (i) a 295-mile interstate transmission pipeline located in northern Alabama, Mississippi and southern Tennessee which transports natural gas to industrial and municipal customers, (ii) a 38-mile and a one mile pipeline in northern Alabama which primarily serve two large industrial customers and (iii) a natural gas marketing company which was subsequently merged into MMI. The acquisition was funded through the Company's existing credit facility.

The MIDLA Acquisition

In October 1997, the Company completed its merger with Republic, which owned MLGC, MLGT, and Mid Louisiana Marketing Company that was subsequently merged into MMI. Consideration for the acquisition included $3.2 million in cash, the assumption of approximately $19.1 million in bank indebtedness, the issuance of 481,247 shares of the Company's common stock and the issuance of warrants to acquire 171,880 shares of common stock. The assets acquired included (i) a 405-mile interstate natural gas pipeline which runs from the Monroe gas field in northern Louisiana, southward through Mississippi to Baton Rouge, Louisiana, (ii) three end-user natural gas pipelines with a collective length of 40 miles and (iii) two offshore lateral natural gas gathering pipelines with a collective length of 8.6 miles. These pipelines serve a number of large industrial and municipal customers. The acquisition was funded through the Company's existing Credit Facility.

The Anadarko Acquisition

In September 1998, MGSI purchased the Anadarko gas gathering system from El Paso Field Services Company, a business unit of El Paso Energy Corporation. The pipeline system was purchased for cash consideration of $35 million. The acquisition was financed through the Company's existing credit facility.

Under the agreement, MGSI acquired ownership and operation of the Anadarko gas gathering system located in Beckham and Roger Mills counties, Oklahoma and Hemphill, Roberts and Wheeler counties, Texas. The system was comprised of over 696 miles of pipeline with an average throughput of 157 MMcf/day and a total capacity of 345 MMcf/day. The system gathers natural gas from approximately 250 wells and includes a 40 MMcf/day natural gas processing facility, 11 compressor stations and interconnections with eight major interstate and intrastate pipeline systems.

The Company expanded the Anadarko system in December 1998 with the acquisition of the Mendota system from Seagull Energy Corporation for $3.75 million. The Mendota system, which was interconnected with the Anadarko System, includes two processing facilities and 35 miles of gathering pipeline.

The Calmar Acquisition

In March 1999, the Company purchased the Calmar system in Alberta, Canada from Probe. The total value of the transaction was approximately $13.2 million (U.S.). The assets purchased include a 30 MMcf per day amine sweetening plant, 30 miles of gas gathering pipeline and approximately 4,000 horsepower of compression located near Edmonton, Alberta. The Calmar system currently gathers and treats sour natural gas from wells operated by Probe and Courage Energy Inc. In conjunction with the purchase, Probe entered into a natural gas gathering and treating agreement with the Company, including the long-term commitment of Probe's reserves in the Leduc Field, a right of first refusal agreement on new or existing midstream assets within a defined 390-square mile area of interest, and an assignment to the Company of an existing third party gathering and treating agreement. The acquisition was funded through the Company's existing credit facility.

The Flare and DPI Acquisitions

In March 1999, the Company purchased two related companies, Flare and DPI. The total value of the transaction was approximately $11.1 million and could include future consideration should certain contingencies be met. The Flare and DPI shareholders received cash consideration of approximately $3.2 million, the Company assumed $5.5 million in debt and the DPI shareholders received 163,719 shares of the Company's common stock. Flare is a natural gas processing and treating company whose principal assets include 27 mobile natural gas processing and treating plants from which it earns revenues based on treating and processing fees and/or a percentage of the NGL's produced. DPI is an NGL, crude oil and CO2 transportation and marketing company. DPI operates 43 NGL and crude oil trucks and trailers, a fleet of 40 pressurized railcars and in excess of 400,000 gallons of NGL storage facilities and product treating and handling equipment. The acquisition was funded through the Company's existing Credit Facility.

The Tinsley Acquisition

In March 1999, the Company purchased the Tinsley crude oil gathering pipeline for $5.2 million. The Tinsley system is located in Mississippi and consists of 60 miles of crude oil gathering pipeline, related truck and Mississippi River barge loading facilities and 170,000 barrels of crude oil storage. The system transports approximately 5,000 barrels of crude oil per day both directly from producing wells and from oil trucked to the pipeline. The acquisition was funded through the Company's existing credit facility.

The Kansas Pipeline Company Acquisition

In November 1999, the Company acquired KPC and other related entities for approximately $195.2 million. KPC owns and operates a 1,120 mile regulated interstate natural gas pipeline system. The system extends into two major segments from northwestern and

northeastern Oklahoma through Wichita and into the Kansas City metropolitan area. The system's two principal customers are divisions of ONEOK, Inc. and Southern Union Company, which are the local distribution companies for Wichita and Kansas City. KPC derives 97% of its gross margin from a series of long-term transportation contracts with these two principal customers. KPC is capable of delivering approximately 140 MMcf per day and 21 MMcf per day of natural gas into the Kansas City and Wichita marketplaces, respectively. KPC is one of only three pipeline systems currently capable of delivering gas into the Kansas City metropolitan market. The acquisition was funded through the Company's existing credit facility.

In conjunction with the acquisition of KPC, the Company opted to terminate a revenue sharing agreement with Management Resources Group, LLC by agreeing to pay approximately $10.8 million on or before January 31, 2000. The full amount was accrued as of December 31, 1999.

The Gloria Acquisition

In December 1999, the Company acquired the Gloria system from Koch Industries for a total price of approximately $6.1 million. The Gloria system is comprised of approximately 133 miles of pipeline with a 1,650 horsepower compressor station, and includes 51 miles of gathering pipeline and 82 miles of transmission pipeline. The system gathers gas from seven producing fields and also directly supplies natural gas to an industrial customer and an LDC in the area. The pipeline was part of Koch's interstate system and FERC approval for the system's abandonment from interstate service was received in October of 1999, which, following the expiration of the required notice period, enabled us to proceed to close the Gloria system acquisition. The acquisition was funded by a common stock offering in December 1999.

Pro Forma Information

The following summarized unaudited Pro Forma Consolidated Income Statement information for the twelve months ended December 31, 1999 and 1998 assumes the Company's acquisition of DPI/Flare, Calmar, SeaCrest, SIGCO, KPC and Gloria had occurred as of January 1, 1998. The unaudited Pro Forma financial results have been prepared for comparative purposes only and may not be indicative of results that would have occurred if the Company had acquired these assets on January 1, 1998 or results which will be attained in the future. Amounts presented below are in thousands, except for per share amounts:

Income Statement	Pro Forma Twelve Months Ended December 31, 1999	1998
	(Unaudited)	
Revenues	$471,794	$425,841
Operating Income	32,779	39,129
Net Income before Extraordinary charge	12,865	17,357
Net Income	12,283	17,357
Net Income per share before extraordinary charge, diluted	$ 1.37	$ 2.38
Net Income per share, diluted	$ 1.31	$ 2.38

The Company utilized the purchase method of accounting to record all of its acquisitions. At the acquisition date, the respective assets and liabilities acquired were recorded at their estimated fair values. Any excess of the purchase price over fair value was allocated to goodwill. With the exception of the DPI/Flare acquisition, no goodwill arose from these transactions.

In connection with its current year acquisition activity, the Company acquired certain assets and liabilities to include approximately $229.8 million in property, plant and equipment, $35.4 million in other noncash assets and $24.3 million in assumed liabilities. Furthermore, the Company issued approximately $2.8 million of treasury stock as consideration.

4. PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following (in thousands):

	December 31, 1999	1998
Property, Plant, and Equipment:		
Transmission	$291,422	$ 75,537
End-user	24,206	18,862
Gathering and processing	77,109	53,401
Corporate & other	1,948	4,255
Construction in progress	12,200	8,500
	406,885	160,555
Less accumulated depreciation	13,916	6,308
Total property, plant, and equipment, net	$392,969	$154,247

Included in construction in progress is an allocation of interest incurred during the period related to the Baton Rouge expansion. Interest capitalized for the years ended December 31, 1999 and 1998 totaled $0.2 million and $0.1 million, respectively. No interest was capitalized in 1997.

5. OTHER ASSETS

Other assets are summarized as follows (in thousands):

	December 31, 1999	December 31, 1998
Regulatory assets, net of accumulated amortization of $6,670 and $585	$16,455	$ 307
Goodwill, net of accumulated amortization of $109	4,031	-
Deferred financing costs, net of accumulated amortization of $46 and $156	1,326	1,049
Other	1,152	1,156
	$22,964	$2,512

6. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES:

Accounts payable and accrued liabilities are summarized as follows (in thousands):

	December 31, 1999	December 31, 1998
Trade accounts payable	$28,068	$28,321
Accrued gas purchases payable	15,835	-
Accrued termination fee	10,750	-
Accrued interest	809	3,963
Accrued other	8,439	256
	$63,901	$32,540

7. LONG-TERM DEBT:

At December 31, 1999 and 1998, the Company had outstanding long-term debt as follows (in thousands):

		December 31, 1999	December 31, 1998
(a)	Note payable by Pan Grande to a bank under a term loan bearing interest at the prime rate plus 1% (9.5% and 8.75% at December 31, 1999 and 1998, respectively), principal and accrued interest are payable in 59 installments of $16,754 with a final payment of the remaining unpaid principal and interest due in May 2000.	$ 71	$ 258
(b)	Revolving credit line with a bank under a $100 million promissory note bearing interest at 7.5% at December 31, 1998 (see following discussion).	-	78,000
	Revolving credit line with a bank for working capital needs under a $100 million promissory note bearing interest at 7.5% at December 31, 1998	-	754
(c)	Revolving credit line with a bank under a $265 million promissory note bearing interest at 8.17% at December 31, 1999 (see following discussion).	240,000	-
	Total debt	240,071	79,012
	Less current portion	(71)	(930)
	Total long-term debt	$240,000	$78,082

(a) In March 1996, Pan Grande, a joint venture owned 70% by the Company, obtained $800,000 from a bank to partially finance the acquisition of six pipelines. The loan is secured by the pipelines and related contracts. Furthermore, members of Pan Grande have guaranteed the loan in an amount equal to their respective ownership interest.

(b) In August 1998, the Company amended and restated its bank financing agreement (the "Credit Agreement") with Bank One. The Credit Agreement increased the Company's borrowing availability, modified the Letter of Credit facility, extended the maturity two years to August 2002, modified financial covenants, established waiver and amendment approvals and changed the fee structure to include a decrease on the interest rate on borrowings.

The Credit Agreement increased the Company's borrowing availability from $80 million to $150 million (with an initial committed amount of $100 million).

Under the Credit Agreement, the credit facility was provided by Bank One, CIBC Oppenheimer, Texas N.A. and Bank of America, collectively the "Lenders." The Company was subject to an initial facility fee of $495,000 which represented all fees due on borrowings up to $100 million. As funds in excess of $100 million are borrowed, a .15% fee will be imposed. The Company's commitment fee remained at .375%. Additionally, the Company was subject to an annual administrative agency fee of $35,000.

In March 1999, the Company further amended the credit agreement to increase the committed amount of borrowing availability from $100 million to $125 million.

(c) In November 1999 and again in March 2000, the Company amended and restated the Credit Agreement. The amendment to the Credit Agreement added additional banks to the syndicate, increased our borrowing availability, modified our letter of credit facility, extended the maturity five years to November 2004, modified financial covenants, established waiver and amendment approvals and changed the method to determine the interest rate to be charged. The unamortized portion of previously capitalized financing costs were written off and recorded as an extraordinary loss totaling $582,000, net of taxes of $300,000, in the fourth quarter of 1999.

The amendment to the Credit Agreement increased the Company's borrowing availability from $125 million to $335 million, with a provision to increase up to $400 million. The amended Credit Agreement provides borrowing availability as follows: (i) up to a $25 million sublimit for the issuance of standby and commercial letters of credit and (ii) the difference between the $335 million and the used sublimit available as a revolving credit facility. At the option of the Company, borrowings under the amended Credit Agreement accrue interest at LIBOR plus an applicable margin or the higher of the Bank of America prime rate or the Federal Funds rate plus an applicable margin.

The applicable margin percentage to be added to the interest rate is based on the Company's debt to total capitalization ratio at the end of each fiscal quarter. The Company is charged a margin between 1.0% and 2.0% as the Company's total debt to total capitalization ratio ranges from under 40% and over 65%, respectively. The Company's borrowings are currently being charged at the margin of 1.75%. In addition, the Company was subject to an arrangement fee, agency fee, underwriting fee, unused fee and commitment fee totaling $1.2 million. Additionally, the Company is subject to an annual administrative agency fee of $35,000.

The credit agreement is collateralized by all accounts receivable, contracts, and the pledge of all of our subsidiaries' stock and a first lien security interest in our pipeline systems. It also contains a number of customary covenants that require the Company to maintain certain financial ratios and limit our ability to incur additional indebtedness, transfer or sell assets, create liens, or enter into a merger or consolidation.

The Company will be required to comply with more stringent debt to capitalization and EBITDA to interest ratios by June 30, 2000. At March 29, 2000, the Company had approximately $94 million of available capacity under its credit agreement.

In an effort to mitigate interest rate fluctuations exposure, the Company has entered into interest rate swaps, under two separate swap agreements, with a combined notional amount of $65 million (See Note 11 - Financial Instruments and Price Risk Management Activities).

The aggregate maturities of long-term debt at December 31, 1999 are as follows (in thousands):

2000	$ 71
2001	-
2002	-
2003	-
2004	240,000
Total	$240,071

8. CAPITAL STOCK:

Common and Preferred Stock

In July 1997, approximately 3.2 million shares of the Company's common stock were issued in a public offering registered under the Securities Act of 1933, as amended, at an offering price of $11.64. Proceeds of $34.6 million, net of issuance costs, were used to repay borrowings on indebtedness incurred on the MIT Acquisition.

In May 1998, the Board and the Company's shareholders approved a resolution to amend the Articles of Incorporation to increase the number of authorized shares of common stock, par value $.01 per share from 10 million to 25 million shares and to authorize 5 million shares of preferred stock.

In connection with the five-for-four stock split discussed below, the Company increased the authorized shares of common stock to 31.25 million shares.

In May 1999, the Company sold 3.57 million shares of its common stock at an offering price of $16.31 per share. Proceeds of $54.5 million, net of issuance costs, were used to pay down existing long-term debt.

In December 1999, the Company sold 2 million shares of its common stock at an offering price of $16.06 per share. Proceeds of $30.2 million, net of issuance costs, were used to repay existing long-term debt, complete the Gloria system acquisition and provide working capital for general corporate purposes.

The Company has five million shares of preferred stock authorized, none of which are outstanding as of December 31, 1999. The preferred stock may be issued in multiple series with various terms, as authorized by the Board. The Company has 12,721,980 shares of common stock issued and 12,560,824 shares of common stock outstanding as of December 31, 1999.

Treasury Stock

From time to time, the Board has authorized the repurchase of the Company's outstanding shares of common stock to be used for specific corporate purposes. During 1999 and 1998, the Company repurchased 143,750 and 181,125 common shares, respectively, at a weighted-average price of $17.71 and $15.41 per share. As of December 31, 1999, and 1998, the Company held 161,156 and 181,125 shares of treasury stock, respectively. In March and June 1999, the Company issued 140,574 and 23,145 shares of treasury stock, respectively, in connection with the DPI/Flare acquisition.

Stock Dividends and Stock Splits

On February 3, 1998, the Board declared a ten percent stock dividend to be paid to shareholders of record at the close of business on February 13, 1998 ("Stock Dividend Record Date") on March 2, 1998. Shareholders of record received one additional share for each ten shares held. No fractional shares were issued and shareholders entitled to a fractional share received a cash payment equal to the market value of the fractional share at the close of the market on the Stock Dividend Record Date.

On February 1, 1999, the Board declared a five-for-four stock split to be paid to shareholders of record at the close of business on February 11, 1999 ("Stock Split Record Date") on March 1, 1999. No fractional shares were issued and shareholders entitled to a fractional share received a cash payment equal to the market value of the fractional share at the close of the market on the Stock Split Record Date.

Warrants

In connection with the Company's August 1996 common stock offering, the Company issued warrants in February 1996 to purchase 47,231 shares of the Company's common stock at $5.71 per share. All of these warrants were exercised in 1998.

Also in connection with the Company's August 1996 common stock offering, the underwriters received warrants to acquire 137,500 shares at 142% of the initial offering price per share. The securities underlying these warrants are subject to piggyback registration rights and expire August 13, 2001. As of December 31, 1999, none of these warrants had been exercised.

In connection with the MIDLA Acquisition, the Company issued warrants to acquire 171,880 shares of Common Stock at $15.82 per share. The securities underlying these warrants are subject to demand and piggyback registration rights and expire in October 2000. As of December 31, 1999, none of these warrants had been exercised.

9. EMPLOYEE BENEFITS:

In December 1996, the Company established a defined contribution 401(k) Profit Sharing Plan for its employees. The plan provides participants a mechanism for making contributions for retirement savings. Each participant may contribute certain amounts of eligible compensation. The Company made a matching contribution to the plan, which was recognized as compensation expense in the year incurred, of approximately $305,000, $83,000 and $81,000 for the years ended December 31, 1999, 1998 and 1997, respectively.

In October 1998, the Board approved an Employee Stock Purchase Plan ("ESPP"), which was subsequently approved by the Company's shareholders in May 1999. The purpose of the ESPP, as amended, is to permit Company employees to purchase the Company's common stock on a monthly basis at a 15% discount from the market price in order to attract and retain dedicated and reliable employees. The maximum number of shares of the Company's common stock which shall be reserved for sale under the ESPP, not including treasury shares or shares purchased in the open market, shall be 100,000 shares. Through December 31, 1999, all shares purchased under the plan have been acquired on the open market. The Company recognized $22,000 and $3,000 of compensation expense during the years ended December 31, 1999 and 1998 related to the ESPP.

10. STOCK OPTION PLANS:

The Company has two stock option plans: the 1996 Incentive Stock Plan (the "Incentive Plan") and the 1997 Non-Employee Director Stock Option Plan (the "Director's Plan").

In May 1996, the Board adopted the Incentive Plan, which was subsequently approved by the Company's shareholders in May 1997. All employees, including officers (whether or not directors) and consultants of the Company and its subsidiaries are currently eligible to participate in the Incentive Plan. Persons who are not in an employment or consulting relationship with the Company or any of its subsidiaries, including non-employee directors, are not eligible to participate in the Incentive Plan. Under the Incentive Plan, 531,250 shares of the Company's common stock are reserved for issuance. In February 2000, the Compensation Committee approved an amendment to the Incentive Plan which increased the shares reserved for issuance from 531,250 to 1,000,000, subject to shareholder approval at the Company's 2000 annual shareholders meeting.

The Incentive Plan provides for the grant of (i) incentive stock options, (ii) shares of restricted stock, (iii) performance awards payable in cash or common stock, (iv) shares of phantom stock, and (v) stock bonuses. In addition, the Incentive Plan provides for the grant of cash bonuses payable when a participant is required to recognize income for federal income tax purposes in connection with the vesting of shares of restricted stock or the issuance of shares of common stock upon the grant of a performance award or a stock bonus, provided that such cash bonus may not exceed the fair market value (as defined) of the shares of Common Stock received on the grant or exercise, as the case may be, of an Incentive Award.

With respect to incentive stock options, no option may be granted more than ten years after the effective date of the stock option plan or exercised more than ten years after the date of the grant (five years if the optionee owns more than 10% of the common stock of the Company at the date of the grant). Additionally, with regard to incentive stock options, the exercise price of the options may not be less than the fair market value of the common stock at the date of the grant (110% if the optionee owns more than 10% of the common stock of the Company). Subject to certain limited exceptions, options may not be exercised unless, at the time of the exercise, the optionee is in the service of the Company. In general, options granted under the incentive plan vest at a rate of one-fifth each year.

Transactions with regard to incentive stock options issued pursuant to the Incentive Plan are as follows:

	Stock Options					
	1999		1998		1997	
	Number of Shares Underlying Options	Weighted Average Exercise Price	Number of Shares Underlying Options	Weighted Average Exercise Price	Number of Shares Underlying Options	Weighted Average Exercise Price
Outstanding at beginning of the year	441,814	$11.32	295,627	$ 8.65	-	$ -
Granted	64,375	16.68	148,125	16.66	295,627	8.65
Exercised	(2,500)	16.80	(688)	7.64	-	-
Forfeited/Repurchased	(39,000)	17.14	(1,250)	16.80	-	-
Outstanding at end of year	464,689	$11.55	441,814	$11.32	295,627	$8.65
Exercisable at end of year	152,289	$ 9.92	86,351	$ 9.24	-	$8.65

The following table summarizes information about incentive stock options outstanding as of December 31, 1999:

	Options Outstanding			Options Exercisable	
Exercise Prices	Number Outstanding	Weighted Average Remaining Years of Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 7.64	140,939	7.10	$ 7.64	56,376	$ 7.64
8.40	78,375	2.10	8.40	31,350	8.40
10.50	72,875	7.42	10.50	41,938	10.50
15.40	14,375	8.74	15.40	2,875	15.40
16.56	59,375	9.60	16.56	-	16.56
16.60	3,125	8.92	16.60	625	16.60
16.80	95,625	8.29	16.80	19,125	16.80
	464,689	6.93	$11.55	152,289	$ 9.92

In April 1997, the Board adopted the Director's Plan, which was subsequently approved by the Company's shareholders in May 1997. The Director's Plan is for the benefit of Directors of the Company, who at the time of their service, are not employees of the Company or any of its subsidiaries. Under the Director's Plan, 150,000 shares of the Company's common stock are reserved for issuance.

The Director's Plan provides for the granting of non-qualified stock options ("NQO"), the provisions of which do not qualify as "incentive stock options" under the Internal Revenue Code. Options granted under the Director's Plan must have an exercise price at least equal to the fair market value of the Company's common stock on the date of the grant. Pursuant to the Director's Plan, options to purchase 15,000 shares of common stock are granted to each non-employee director upon their election to the Board. In addition, all non-employee Directors are eligible to receive a NQO to purchase 5,000 shares of common stock at the time of the Directors re-election to the Board, subject to share availability. Options granted under the Director's Plan are fully vested upon issue and expire ten years after the date of the grant. As of December 31, 1999, 50,000 non-qualified stock options have been issued at option prices ranging from $11.00 to $18.40 per share and all of these options were exercisable as of that date at a weighted average price of $14.34 per share.

The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

ASSUMPTION:	1999	1998	1997
Expected Term in Years	6.35	6.60	6.57
Expected Volatility	33.04%	36.29%	36.29%
Expected Dividends	0.4%	0.4%	0.4%
Risk-Free Interest Rate	5.95%	5.59%	6.38%

The Black-Scholes weighted average fair value of all options granted under both plans during 1999, 1998 and 1997 was $7.10, $7.54 and $4.09, respectively.

The Company applies APB Opinion No, 25, Accounting for Stock Issued to Employees, and related Interpretations in accounting for its plans. Accordingly, no compensation cost has been recognized for its stock option plans. Had compensation expense for the Company's stock-based compensation plans been determined applying the provisions of SFAS No. 123, The Company's net income and net income per common share for 1999, 1998 and 1997 would approximate the pro forma amounts below (in thousands, except per share data):

	December 31, 1999		December 31, 1998		December 31, 1997	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
Net income	$11,439	$11,121	$9,113	$8,317	$5,764	$5,686
Basic earnings per share	$ 1.25	$ 1.21	$ 1.29	$ 1.18	$ 1.13	$ 1.11
Diluted earnings per share	$ 1.22	$ 1.18	$ 1.25	$ 1.14	$ 1.10	$ 1.08

11. FINANCIAL INSTRUMENTS AND PRICE RISK MANAGEMENT ACTIVITIES:

FAIR VALUE OF FINANCIAL INSTRUMENTS

As of December 31, 1999 and 1998, the carrying amounts of certain financial instruments held by the Company, including cash, cash equivalents, trade receivables and payables and short-term borrowings are representative of fair value because of the short-term maturity of these instruments. The fair value of long-term debt with variable interest rates approximates the carrying value because of the variable nature of the debt's interest rate. The fair value of all derivative financial instruments is the estimated amount at which management believes the instruments could be liquidated over a reasonable period of time, based on quoted market prices, current market conditions or other estimates obtained from third-party brokers or dealers.

PRICE RISK MANAGEMENT ACTIVITIES

The Company utilizes derivative financial instruments to manage market risks associated with certain energy commodities and interest rates. According to guidelines provided by the Board, the Company enters into exchange-traded commodity futures, options and swap contracts to reduce the exposure to market fluctuations in price and transportation costs of energy commodities and fluctuations in interest rates. The Company does not engage in speculative trading. Approvals are required from senior management prior to the execution of any derivative transactions.

Commodity Price Risk:

The Company's commodity price risk exposure arises from inventory balances and fixed price purchase and sale commitments. The Company uses exchange-traded commodity futures contracts, options and swap contracts to manage and hedge price risk related to these market exposures. These futures and options contracts have pricing terms indexed to the NYMEX.

Gas futures involve the buying and selling of natural gas at a fixed price. Over-the-counter swap agreements require the Company to receive or make payments based on the difference between a specified price and the actual price of natural gas. The Company uses futures and swaps to manage margins on offsetting fixed-price purchase or sales commitments for physical quantities of natural gas. Options held provide the right, but not the obligation, to buy or sell energy commodities at a fixed price. The Company utilizes options to manage margins and to limit overall price risk exposure.

The gains, losses and related costs of the financial instruments that qualify as a hedge are not recognized until the underlying physical transaction occurs. At December 31, 1999 and 1998, the Company had unrealized losses from such hedging contracts of $1,139,000 and $896,000, respectively. The market value, notional amount and notional contract quantity of open commodity futures, options and swaps contracts used for hedging purposes were as follows (in thousands):

	As of December 31,	
	1999	1998
Market Value - Unrealized Loss:		
Swap contracts	$(1,027)	$ (695)
Futures contracts	(112)	(178)
Options contracts	-	(23)
Notional Contract Amount:		
Swap contracts	$10,635	$11,729
Futures contracts	2,295	683
Options contracts	-	23
Notional Contract Quantity (MMBtu):		
Swap contracts	5,045	5,606
Futures contracts	930	270
Options contracts	-	120

Interest Rate Risk:

The Company's Credit Facility provides an option for the Company to borrow funds at a variable interest rate of LIBOR plus an applicable margin based on the Company's debt to total capitalization ratio. In an effort to mitigate interest rate fluctuation exposure, the Company entered into interest rate swaps under two separate swap agreements with a combined notional amount of $65 million dollars. The interest rate swap agreements entered into by the Company effectively convert $65 million of floating-rate debt to fixed-rate debt.

The first interest rate swap agreement was entered into with Bank One in December 1997. The swap agreement effectively established a fixed three-month LIBOR interest rate setting of 6.02% for a two-year period on a notional amount of $25 million. This swap agreement was subsequently transferred to Bank of America in November 1998 and replaced with a new swap agreement. The new swap agreement provides a fixed 5.09% three-month LIBOR interest rate to the Company with a new two year termination date of December 2000 which may, however, be extended through December 2003 at Bank of America's option on the last day of the initial term. The variable three-month LIBOR rate is reset quarterly based on the prevailing market rate and the Company is obligated to reimburse Bank of America when the three-month LIBOR rate is reset below 5.09%. Conversely, Bank of America is obligated to reimburse the Company when the three-month LIBOR rate is reset above 5.09%. At December 31, 1999 and 1998, the fair value of this interest rate swap through the initial termination date was a net asset of approximately $303,000 and a net liability of approximately $20,000, respectively.

The second interest rate swap agreement was entered into with CIBC in October 1998. The swap agreement effectively established a fixed three-month LIBOR interest rate setting of 4.475% for a three-year period on a notional amount of $40 million. The agreement, however, may be extended an additional two years through November 2003 at CIBC's option on the last day of the initial term. The variable three-month LIBOR rate is reset quarterly based on the prevailing market rate and the Company is obligated to reimburse CIBC when the three-month LIBOR rate is reset below 4.475%. Conversely, CIBC is obligated to reimburse the Company when the three-month LIBOR rate is reset above 4.475%. At December 31, 1999 and 1998, the fair value of this interest rate swap through the initial termination date was a net asset of approximately $1,279,000 and $481,000, respectively.

The effect of these swap agreements was to lower interest expense by $377,000 and $37,000 in 1999 and 1998, respectively, and increase interest expense by $2,000 in 1997.

12. CONCENTRATION OF CREDIT RISK:

The Company derives revenue from commercial companies located in the United States and Canada. Four of the Company's largest customers account for 11% or approximately $6.0 million of the outstanding accounts receivable at December 31, 1999. The Company performs ongoing evaluations of its customers and generally does not require collateral. The Company assesses its credit risk and provides an allowance for doubtful accounts for any accounts that it deems doubtful of collection. At December 31, 1999 and 1998, $1,484,000 and $92,000, respectively, was reserved as a provision for doubtful accounts.

The change in market value of futures and option contracts requires daily cash settlement in margin accounts with brokers. At December 31, 1999 and 1998, the Company had $893,000 and $181,000, respectively, in margin cash accounts to service these derivative financial instruments. Swap contracts and most other over-the-counter instruments are generally settled at the expiration of the contract term. The Company is exposed to credit risk in the event of nonperformance by a counterparty. For each counterparty, the Company analyzes its financial condition prior to entering into the agreement, establishes credit limits and monitors the appropriateness of these limits on an ongoing basis.

13. INCOME TAXES:

The Company has NOL carryforwards of approximately $10.3 million, expiring in various amounts from 2003 through 2018. These loss carryforwards were generated by the companies acquired by Midcoast. The ability of the Company to utilize the carryforwards is dependent upon the Company generating sufficient taxable income and will be affected by annual limitations (currently estimated at $5.2 million) on the use of such carryforwards due to a change in shareholder control under section 382 of the Internal Revenue Code triggered by the Company's July 1997 Common Stock offering and the change of ownership created by the MIDLA acquisition and DPI/Flare acquisition.

The tax effects of significant temporary differences representing deferred tax assets and liabilities at December 31, 1999 and 1998, are as follows (in thousands):

	December 31,	
	1999	1998
NOL carryforwards	$ 3,510	$ 5,644
Alternative minimum tax credit	2,104	420
Valuation allowance	(2,464)	(4,554)
Financial net book value of assets in excess of tax net book value of assets	(14,184)	(12,318)
Net deferred tax liabilities	$(11,034)	$(10,808)

The valuation allowance declined $2.1 million during the year ended December 31, 1999. The decline was the net result of current year utilization of net operating losses to offset taxable income and the removal of $581,000 of valuation allowance related to net operating losses that are more likely than not to be utilized in the future.

A reconciliation of the provision for income taxes to the statutory United States tax rate is as follows (in thousands):

	For The Year Ended December 31,		
	1999	1998	1997
Federal tax computed at statutory rate	$ 4,832	$ 3,543	$ 1,960
Utilization of net operating loss carryforwards	(1,989)	(1,145)	(1,810)
Reduction in valuation allowance	(581)	(1,089)	-
Foreign jurisdiction tax rate difference	(146)	-	-
Other	53	-	-
Actual provision	$ 2,169	$ 1,309	$ 150

United States income taxes have not been provided on the cumulative undistributed earnings, which totaled approximately $589,000 at December 31, 1999, of the Company's Canadian subsidiaries since it is the Company's intention to reinvest such earnings indefinitely.

14. COMMITMENTS AND CONTINGENCIES:

Employment Contracts

Certain executive officers of the Company have entered into employment contracts which, through amendments, provide for employment terms of varying lengths, the longest of which expires in December 2002. These agreements may be terminated by mutual consent or at the option of the Company for cause, death or disability. In the event termination is due to death, disability or defined changes

in the ownership of the Company, the full amount of compensation remaining to be paid during the term of the agreement will be paid to the employee or their estate, after discounting at 12% to reflect the current value of unpaid amounts.

Leases

The Company incurred net lease expenses of $1.0 million, $0.2 million and $0.1 million during the years ended 1999, 1998 and 1997. As of December 31, 1999, future minimum lease payments due under these leases are approximately $1.1 million, $0.5 million, $0.1 million and $0.1 million for the years ended December 31, 2000, 2001, 2002 and 2003, respectively.

MIT Acquisition Contingency

As part of the MIT acquisition, the Company has agreed to pay additional contingent annual payments to Atrion, not to exceed $250,000 per year, which will be treated as deferred purchase price adjustments. The amount each year is dependent upon revenues received by the Company from certain gas transportation contracts. The contingency is due over an eight-year period commencing April 1, 1998 and payable at the end of each anniversary date. The Company is obligated to pay the lesser of 50% of the gross revenues received under these contracts or $250,000. As of December 31, 1999, the Company has made one payment of $250,000 and has accrued an additional $187,500 under the contingency.

MIDLA Acquisition Contingency

As part of the MIDLA acquisition, the Company agreed that if a specific contract with a third party was executed prior to October 2, 1999, which included specific provisions regarding price and throughputs, the Company would be obligated to issue 137,500 warrants to Republic to acquire common stock at an exercise price of $15.82 per share. In addition, concurrent with initial expenditures on the project, the Company would incur a $1.2 million cash obligation to Republic. At December 31, 1999, none of the provisions of this contingency were met and the obligation expired.

DPI Acquisition Contingency

As part of the DPI acquisition, the Company agreed that in the event that the Company approves long-term DPI or Flare projects and these projects are placed under contract and in service, the Company would be obligated to pay the DPI shareholders an additional consideration of up to $2.5 million. This contingency expires on March 11, 2002.

15. EARNINGS PER SHARE:

Basic and diluted earnings per share amounts calculated in accordance with SFAS No. 128, "Earnings Per Share," are presented below for the years ended December 31 (in thousands, except per share amounts):

	1999			1998			1997		
	Net Income	Average Shares Outstanding	Earnings Per Share	Net Income	Average Shares Outstanding	Earnings Per Share	Net Income	Average Shares Outstanding	Earnings Per Share
Basic	$11,439	9,176	$1.25	$9,113	[illegible]	$1.29	$5,764	5,115	$1.13
Effect of dilutive securities:									
Stock options	-	159	(.02)	-	151	(.03)	-	56	(.02)
Warrants	-	66	(.01)	-	73	(.01)	-	50	(.01)
Diluted	$11,439	9,401	$1.22	$9,113	[illegible]	$1.25	$5,764	5,251	$1.10

16. SEGMENT DATA:

The Company conducts its business of transporting, gathering, processing and marketing of natural gas and other petroleum products through three reportable segments. The Company's operations are segregated into reportable segments based on the type of business activity and type of customer served. The Company's transmission pipelines primarily receive and deliver natural gas to and from other pipelines, and secondarily, provide end-user or gathering functions. Transportation fees are received by the Company for transporting gas owned by other parties through the Company's pipeline systems. The Company's end-user pipelines provide natural gas and natural gas transportation services to industrial customers, municipalities or electrical generating facilities through interconnect gas pipelines constructed or acquired by the Company. These pipelines provide a direct supply of natural gas to new industrial facilities or to existing facilities as an alternative to the local distribution company. The Company's gathering systems typically consist of a network of pipelines

which collect natural gas or crude oil from points near producing wells, process the natural gas, and transport oil and natural gas to larger pipelines for further transmission. The Company's natural gas processing revenues are realized from the extraction and sale of NGL's as well as the sale of the residual natural gas. All of the Company's segments have significant revenues from gas marketing activities.

The Company evaluates performance based on profit or loss from operations before income taxes and other income and expense items incidental to core operations. Operating income for each segment includes total revenues less operating expenses (including depreciation) and excludes corporate administrative expenses, interest expense, interest income and income taxes. For the year ended December 31, 1999, no customer represented in excess of 10% of the total revenue of the Company. For the years ended December 31, 1998 and 1997, the Company derived 12% of total revenue from a transmission segment customer. The accounting policies of the segments are the same as those described in the summary of significant accounting policies (see Note 2).

	AS OF OR FOR THE YEAR ENDED DECEMBER 31, 1999				
	TRANSMISSION PIPELINES	END-USER PIPELINES	GATHERING AND PROCESSING	OTHER	TOTAL
	(IN THOUSANDS)				
Revenues					
Domestic	$124,789	$125,441	$136,805	$ 2,394	$389,429
Foreign	-	-	2,142	-	2,142
Total Revenues	124,789	125,441	138,947	2,394	391,571
Gross Margin	19,088	7,854	10,706	1,916	39,564
Depreciation and Amortization	(2,417)	(899)	(3,621)	(608)	(7,545)
General & Administrative	-	-	-	(8,431)	(8,431)
Interest Expense	-	-	-	(6,533)	(6,533)
Other, net	-	-	-	(2,865)	(2,865)
Income before income taxes and extraordinary charge	$ 16,671	$ 6,955	$ 7,085	$(16,521)	$ 14,190
Assets					
Domestic	$336,555	$ 29,949	$ 88,679	$ 9,821	$465,004
Foreign	-	-	13,368	-	13,368
Total Assets	$336,555	$ 29,949	$102,047	$ 9,821	$478,372
Capital Expenditures	2,524	5,858	4,579	3,601	16,562

	AS OF OR FOR THE YEAR ENDED DECEMBER 31, 1998				
	TRANSMISSION PIPELINES	END-USER PIPELINES	GATHERING AND PROCESSING	OTHER	TOTAL
	(IN THOUSANDS)				
Total Revenues (all from domestic sources)	$118,311	$99,720	$15,600	$ 438	$234,069
Gross Margin	13,039	5,233	4,357	438	23,067
Depreciation and Amortization	(1,554)	(532)	(841)	(270)	(3,197)
General & Administrative	-	-	-	(6,317)	(6,317)
Interest Expense	-	-	-	(3,247)	(3,247)
Other, net	-	-	-	116	116
Income before income taxes and extraordinary charge	$ 11,485	$ 4,701	$ 3,516	$(9,280)	$ 10,422
Total Assets (all from domestic sources)	$121,498	$ 8,055	$53,246	$ 8,543	$191,342
Capital Expenditures	1,648	6,168	-	-	7,816

	AS OF OR FOR THE YEAR ENDED DECEMBER 31, 1997				
	TRANSMISSION PIPELINES	END-USER PIPELINES	GATHERING AND PROCESSING	OTHER	TOTAL
	(IN THOUSANDS)				
Total Revenues (all from domestic sources)	$ 64,787	$36,349	$11,246	$ 362	$112,744
Gross Margin	5,862	3,468	2,717	362	12,409
Depreciation and Amortization	(553)	(421)	(341)	(277)	(1,592)
General & Administrative	-	-	-	(3,526)	(3,526)
Interest Expense	-	-	-	(1,067)	(1,067)
Other, net	-	-	-	(310)	(310)
Income before income taxes and extraordinary charge	$ 5,309	$ 3,047	$ 2,376	$(4,818)	$ 5,914
Total Assets (all from domestic sources)	$104,479	$ 6,452	$ 9,863	$ 7,244	$128,038
Capital Expenditures	163	414	833	-	1,410

17. SUPPLEMENTAL SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
1999				
Operating revenues	$82,064	$83,457	$101,844	$124,206
Operating income	5,473	4,566	3,891	6,973
Net income before extraordinary item	3,255	2,576	2,758	3,432
Net income	3,255	2,576	2,758	2,850
Basic earnings per share before extraordinary item	0.47	0.31	0.26	0.31
Diluted earnings per share before extraordinary item	0.46	0.31	0.26	0.31
Basic earnings per share	0.47	0.31	0.26	0.26
Diluted earnings per share	0.46	0.31	0.26	0.26
1998				
Operating revenues	$67,339	$49,545	$ 50,301	$ 66,884
Operating income	4,134	2,551	2,589	4,279
Net income	2,761	1,728	1,580	3,044
Basic earnings per share	0.39	0.24	0.22	0.44
Diluted earnings per share	0.38	0.23	0.22	0.43

18. UNUSUAL CHARGE

During the fourth quarter of fiscal 1999, the Company recorded a pre-tax unusual charge totaling $2.7 million ($2.2 million after tax) related to streamlining efforts announced in November 1999. The charge primarily relates to the severance and benefits of approximately 50 employees who were involuntary terminated. The Company anticipates savings from reduced employee cost and more streamlined operating and business processes. At December 31, 1999, an accrued liability of $1.8 million related to the severance charge was included in "Accounts payable and accrued liabilities" on the consolidated balance sheet. Thirty-three of these employees were still employed with the Company at December 31, 1999. The final severance charge will be paid in April 2002.

19. SUBSEQUENT EVENTS (UNAUDITED):

In January 2000, the Company entered into a definitive purchase and sale agreement to acquire MBPL from Triumph Energy Corporation for cash consideration of approximately $5.7 million (U.S.), plus certain future contingent payments based on the actual throughput volumes. MBPL consists of 90 miles of crude oil pipeline that originates at the Manyberries Oil Field and terminates at an interconnection with the Milk River Pipeline system in southeast Alberta, Canada. Truck terminals, including the Legend terminal, and a significant amount of crude oil storage also contribute to the operations. The system has a design capacity of approximately 21,000 BBLs/day and transports light sour crude oil from the Manyberries oil field, as well as additional crude oil volumes from the Legend truck terminal. The pipeline system is the only light gravity system in southern Alberta and current volumes are

approximately 6,500 Bbls/day. Closing is anticipated in the second quarter of 2000, subject to receipt of the approvals, consents or other authorizations required by the Investment Canada Act.

In March 2000, the Company acquired the Provost natural gas plant and gathering system from NovaGas Canada LP, a division of TransCanada, for approximately $4.9 million (U.S.). The Provost acquisition includes 80 miles of natural gas gathering pipeline and a 15 MMcf/day sour gas processing plant and sour gas injection well. The system is located in east-central Alberta, Canada and is the only sour gas gathering and processing system in the area. The system is connected to 21 oil tank batteries and primarily gathers the associated sour gas production from approximately 900 wells in the Provost area. The acquisition was funded through the Company's existing credit facility.

In March 2000, the Company amended the existing credit agreement to increase the committed amount of borrowing availability from $265 million to $335 million.

REPORT OF INDEPENDENT ACCOUNTANTS
ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Shareholders
of Midcoast Energy Resources, Inc.:

Our audit of the consolidated financial statements of Midcoast Energy Resources, Inc. and its subsidiaries as of December 31, 1999 and for the year then ended also included an audit of the financial statement schedule for the year ended December 31, 1999, listed in Item 14(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein for the year ended December 31, 1999, when read in conjunction with the related consolidated financial statements.

PRICEWATERHOUSECOOPERS LLP

Houston, Texas
March 10, 2000

INDEPENDENT AUDITOR'S REPORT ON SCHEDULE

Stockholders and Board of Directors
Midcoast Energy Resources, Inc.
Houston, Texas

We have audited the consolidated financial statements Midcoast Energy Resources, Inc. and subsidiaries as of December 31, 1998, and for each of the years in the two-year period ended December 31, 1998. Our audits for such years also included the financial statement schedule of Midcoast Energy Resources, Inc. and subsidiaries, listed in Item 14-2, for each of the years in the two-year period ended December 31, 1998. This financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth herein.

HEIN + ASSOCIATES LLP
Houston, Texas
March 18, 1999

SCHEDULE II

MIDCOAST ENERGY RESOURCES, INC.
VALUATION AND QUALIFYING ACCOUNTS

YEARS ENDED DECEMBER 31, 1999, 1998, AND 1997
(IN THOUSANDS)

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
1999					
Allowance for doubtful accounts.....	$ 92	$ 12	$1,380 (h)	$ -	$1,484
Valuation allowance on deferred tax assets....	$4,554	$ (581)(c)	$ 480 (g)	$(1,989)(f)	$2,464
1998					
Allowance for doubtful accounts.....	$ 494	$ -	$ (309)(a)	$ (93)(b)	$ 92
Valuation allowance on deferred tax assets....	$4,581	$(1,089)(c)	$2,207 (d)(e)	$(1,145)(f)	$4,554
1997					
Allowance for doubtful account.....	$ -	$ -	$ 494 (a)	$ -	$ 494
Valuation allowance on deferred tax assets....	$3,727	$ -	$2,664 (d)	$(1,810)(f)	$4,581

(a) Due to MIDLA Acquisition.
(b) Represents uncollectible accounts written off.
(c) Removal of valuation allowance on deferred tax assets that are more likely than not to be utilized in the future.
(d) Adjustment of federal net operating loss carryforwards and related valuation allowance to reconcile to federal income tax return.
(e) Valuation allowance on federal net operating loss carryforwards acquired in connection with the MIDLA Acquisition.
(f) Represents utilization of federal net operating loss carryforwards.
(g) Valuation allowance on federal net operating loss carryforwards and alternative minimum tax credits acquired in connection with the DPI Acquisition.
(h) Due to KPC acquisition.

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

On October 11, 1999, PricewaterhouseCoopers LLP was engaged as independent accountant to audit the financial statements of the Company for the year ended December 31, 1999. In connection therewith, on October 11, 1999, the Company and Hein & Associates LLP, the Company's prior principal independent accountant, mutually agreed that Hein + Associates LLP would be replaced by PricewaterhouseCoopers LLP as the Company's principal independent accountant. The decision to replace Hein + Associates LLP and engage PricewaterhouseCoopers LLP was approved by the Board of Directors of the Company.

The accounting firm of Hein + Associates LLP served as the independent accountant for the Company from March 17, 1994 until dismissed by the Company on October 11, 1999. Midcoast and Hein have not, in connection with the audit of Midcoast's financial statements for each of the prior two years ended December 31, 1998 and December 31, 1997 or for any subsequent interim period prior to and including October 11, 1999, had any disagreement on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreement, if not resolved to Hein's satisfaction, would have caused Hein to make reference to the subject matter of the disagreement in connection with its reports.

The reports of Hein on the Midcoast financial statements for the past two fiscal years did not contain an adverse opinion or a disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principles. Midcoast had no relationship with PricewaterhouseCoopers LLP required to be reported pursuant to Regulation S-K item 304 (a) (2) during the two fiscal periods ended December 31, 1998 and December 31, 1997 or for any subsequent interim period prior to and including October 11, 1999.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

ITEM 11. EXECUTIVE COMPENSATION.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Pursuant to instruction G (3) to Form 10-K, Items 10, 11, 12 and 13 are omitted because the Company will file with the SEC a definitive proxy statement (the "Proxy Statement") pursuant to regulation 14A under the Securities Exchange Act of 1934 not later than 120 days after the close of the fiscal year. The information required by such Items will be included in the Proxy Statement to be filed in connection with the Company's annual meeting of shareholders scheduled for May 16, 1999 and is hereby incorporated by reference.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FROM 8-K.

The following documents are filed as part of this report:

1. Financial Statements

The following consolidated financial statements of Midcoast Energy Resources, Inc. and subsidiaries are included in Part II, Item 8 of this Form 10-K.

	Page
Reports of Independent Accountants.....	25
Consolidated Balance Sheets.....	27
Consolidated Statements of Operations.....	28
Consolidated Statements of Comprehensive Income....	29
Consolidated Statements of Shareholders' Equity....	30
Consolidated Statements of Cash Flows.....	31
Notes to Consolidated Financial Statements.....	32

2. Financial statement schedules and supplementary information required to be submitted.

	Page
Schedule II - Valuation and qualifying accounts....	57
Schedules other than that listed above are omitted because they are not applicable	

3. An exhibit list is included on page 54 of this Form 10-K.

(B) REPORTS ON FORM 8-K:

An 8-K was filed on October 15, 1999 to report the change of independent accountant from Hein + Associates LLP to PricewaterhouseCoopers LLP.

A report on Form 8-K was filed on November 19, 1999 to report the KPC acquisition and the amendment to the existing credit agreement. A report on Form 8-KA was filed on December 3, 1999 as an amendment to the Form 8-K filed on November 19, 1999. The amendment was filed to include the required audited historical summary of revenue and direct operating expenses of Kansas Pipeline Company for the nine months ended September 30, 1999. In addition, the unaudited Midcoast Pro Forma Statement of Operations for the nine months ended September 30, 1999 and for the year ended December 31, 1998 and unaudited Pro Forma Balance Sheet at September 30, 1999 were included.

A report on Form 8-K/A was filed on December 2, 1999 as an amendment to the report on Form 8-K filed September 29, 1999 relating the Company's reincorporation in Texas. The amendment was filed to include specific language adopting the pre-reincorporation company's registration statement and under the Securities Exchange Act of 1934 (1934 Act) such that the common stock of the Company after the reincorporation would be deemed to be registered under the 1934 Act.

A report on Form 8-K was filed on December 10, 1999 to report the terms of the Underwriting Agreement that the Company entered in connection with its public offering of common stock, in which the agreement was included as an exhibit to the report.

A report on Form 8-K was filed on December 14, 1999 to report the streamlining of its operations.

MIDCOAST ENERGY RESOURCES, INC.
EXHIBIT LIST
December 31, 1999

Each exhibit identified below is filed as a part of this report. An asterisk designates exhibits not incorporated by reference to a prior filing; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	DESCRIPTION OF EXHIBITS
2.1	Agreement for Sale and Purchase of Harmony Gas Processing Plant and Related Gathering System dated October 3, 1996, by and between Koch Hydrocarbon Company, a division of Koch Industries, Inc. and Midcoast Holdings No. One, Inc. (Incorporated by reference from Midcoast Form 8-K dated October 21, 1996, as Exhibit 2.1).
2.2	Stock Purchase Agreement dated March 18, 1997, by and between Midcoast Energy Resources, Inc. and Atrion Corporation. (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1996, as Exhibit 2.7).
2.3	Agreement and Plan of Merger dated October 31, 1997 by and between Republic Gas Partners, LLC. And Midcoast Energy Resources, Inc. (Incorporated by reference from Midcoast Form 8-K dated November 13, 1997 as Exhibit 2.2)
2.4	Purchase and Sale Agreement dated September 9, 1998, by and between El Paso Field Services Company, a Delaware corporation, and Midcoast Gas Services, Inc., a Delaware corporation. (Incorporated by reference from Midcoast Form 10-Q for the nine month period ended September 30, 1998, as Exhibit 2.8).
2.5	Agreement and Plan of Merger dated March 11, 1999, by and between Dufour Petroleum, Inc., Flare L.L.C. Partners and Midcoast Energy Resources, Inc. (Incorporated by reference from Midcoast Form 10-K for the fiscal year ended December 31, 1998).
2.6	Purchase and Sale Agreement dated March 23, 1999, by and between Probe Exploration Inc. and Midcoast Canada Operating Corporation. (Incorporated by reference from Midcoast Form 10-K for the fiscal year ended December 31, 1998).
2.7	Asset Purchase Agreement dated November 9, 1999 by and between K-Pipe Merger Corporation, Midcoast Energy Resources, Inc., Midcoast Kansas Pipeline, Inc., and Midcoast Kansas General Partner, Inc. (Incorporated by reference from Midcoast Form 8-K dated November 9, 1999 as Exhibit 2.4)
3.1	Articles of Incorporation of Midcoast Energy Resources, Inc. (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1992).
3.2	Certificate of Amendment of Articles of Incorporation of Midcoast Energy Resources, Inc. (Incorporated by reference from Midcoast Registration Statement on Form SB-2 (No. 333-4643) dated August 8, 1996).
3.3	Certificate of Amendment of Articles of Incorporation of Midcoast Energy Resources, Inc. dated May 15, 1998 (Incorporated by reference from Midcoast Form 10-Q for the six month period ended June 30, 1998 as Exhibit 3.4).
3.4	Certificate of Stock Split of Midcoast Energy Resources, Inc. dated February 24, 1999. (Incorporated by reference from Midcoast Form 10-K for the fiscal year ended December 31, 1998).
3.5	Bylaws of Midcoast Energy Resources, Inc. (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1992)
3.6	Plan of Agreement of Merger between the Company and the Corporation dated September 22, 1999. (Incorporated by reference from Midcoast Form 8-K dated September 29, 1999, as Exhibit 2.1).
3.7	Amended and Restated Articles of Incorporation dated September 23, 1999. (Incorporated by reference from Midcoast Form 8-K dated September 29, 1999, as Exhibit 3.1).
3.8	Bylaws of the Texas Corporation dated September 22, 1999. (Incorporated by reference from Midcoast Form 8-K dated September 29, 1999, as Exhibit 3.2).
4.1	Specimen Certificate for Shares of Common Stock, par value $.01 per share. (Incorporated by reference from Midcoast Registration Statement on Form SB-2 (No. 333-4643) dated August 8, 1996).
4.2	Representative's Warrants. (Incorporated by reference from Midcoast Registration Statement on Form SB-2 (No. 333-4643) dated August 8, 1996).

4.3 Voting Proxy Agreement dated August 5, 1996, by and between Midcoast Energy Resources, Inc., Stevens G. Herbst, Kenneth B. Holmes, Jr., Rainbow Investments Company and Texas Commerce Bank National Association. (Incorporated by reference from Midcoast Registration Statement on Form SB-2 (No. 333-4643) dated August 8, 1996).

4.4 Registration Rights Agreement dated August 5, 1996, by and between Midcoast Energy Resources, Inc. and Stevens G. Herbst. (Incorporated by reference from Midcoast Registration Statement on Form SB-2 (No. 333-4643) dated August 8, 1996).

4.5 Registration Rights Agreement dated August 5, 1996, by and between Midcoast Energy Resources, Inc. and Kenneth B. Holmes, Jr. (Incorporated by reference from Midcoast Registration Statement on Form SB-2 (No. 333-4643) dated August 8, 1996).

4.6 Registration Rights Agreement dated August 5, 1996, by and between Midcoast Energy Resources, Inc. and Rainbow Investments Company. (Incorporated by reference from Midcoast Registration Statement on Form SB-2 (No. 333-4643) dated August 8, 1996).

4.7 Executive Severance Agreement by and between Midcoast Energy Resources, Inc. and Dan Tutcher, dated August 15, 1997. (Incorporated by reference from Form 10-K for the year ended December 31, 1997 as Exhibit 4.11)

4.8 Executive Severance Agreement by and between Midcoast Energy Resources, Inc. and I.J. Berthelot, II, dated August 15, 1997. (Incorporated by reference from Form 10-K for the year ended December 31, 1997 as Exhibit 4.12)

4.9 Executive Severance Agreement by and between Midcoast Energy Resources, Inc. and Richard Robert, dated August 15, 1997. (Incorporated by reference from Form 10-K for the year ended December 31, 1997 as Exhibit 4.13)

4.10 Executive Severance Agreement by and between Midcoast Energy Resources, Inc. and Duane Herbst, dated August 15, 1997. (Incorporated by reference from Form 10-K for the year ended December 31, 1997 as Exhibit 4.14)

4.11 First Amendment to Voting/Proxy Agreement dated April 29, 1998 by and between Midcoast Energy Resources, Inc. and Steven G. Herbst, June Herbst, Kenneth Holmes, Jr., Dorothy C. Holmes and Rainbow Investments Company and Chase Bank of Texas. (Incorporated by reference from Form 10-Q for the three months ended March 31, 1998 as Exhibit 4.14)

10.1 Employment Agreement dated January 1, 1993, by and between Midcoast Energy Resources, Inc. and Dan C. Tutcher (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1992).

10.2 Amendment to the Employment Agreement dated April 1, 1993, by and between Midcoast Energy Resources, Inc. and Dan C. Tutcher (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1993).

10.3 Amendment to Employment Agreement dated April 14, 1997, by and between Midcoast Energy Resources, Inc. and Dan Tutcher (Incorporated by reference from Midcoast Form 10-QSB for the three-month period ended March 31, 1997).

10.4 Employment Agreement dated April 30, 1994, by and between Midcoast Energy Resources, Inc. and Richard A. Robert (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1994).

10.5 Amendment to the Employment Agreement dated April 8, 1996, by and between Midcoast Energy Resources, Inc. and Richard A. Robert (Incorporated by reference from Midcoast Form 10-QSB for the three-month period ended March 31, 1996).

10.6 Employment Agreement dated April 25, 1995, by and between Midcoast Energy Resources, Inc. and I.J. Berthelot, II (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1995).

10.7 Amendment to Employment Agreement dated April 14, 1997, by and between Midcoast Energy Resources, Inc. and I.J. Berthelot, II (Incorporated by reference from Midcoast Form 10-QSB for the three-month period ended March 31, 1997).

10.8 Amendment to Employment Agreement dated December 8, 1995, by and between Midcoast Energy Resources, Inc. and I.J. Berthelot, II (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1995).

10.9 Assignment of Net Revenue Interest dated July 1, 1994, by and between Texline Gas Company and Midcoast Energy Resources, Inc. (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1994).

10.10 Assignment of Net Revenue Interest dated July 1, 1994, by and between Rainbow Investments Co. and Midcoast Energy Resources, Inc. (Incorporated by reference from Midcoast Form 10-KSB for the fiscal year ended December 31, 1994).

10.11 Midcoast Energy Resources, Inc. 1996 Incentive Stock Plan, as amended on May 15, 1998. (Incorporated by reference from Midcoast Form 10-K for the fiscal year ended December 31, 1998).

10.12 Credit Agreement dated August 22, 1996, by and between Bank One, Texas N.A. and Midcoast Energy Resources, Inc., Magnolia Pipeline Corporation and H&W Pipeline Corporation. (Incorporated by reference from Midcoast Form 10-QSB for the nine-month period ended September 30, 1996).

10.13 Midcoast Energy Resources, Inc. 1997 Non-Employee Director Stock Option Plan (Incorporated by reference from Midcoast Form 10-QSB for the three-month period ended March 31, 1997).

10.14 Indemnity Agreement dated April 23, 1997 between Midcoast Energy Resources, Inc. and Richard A. Robert (Incorporated by reference from Midcoast Registration Statement on Form S-1 (No. 333-27885) dated June 26, 1997).

10.15 Indemnity Agreement dated April 23, 1997 between Midcoast Energy Resources, Inc. and I.J. Berthelot, II. (Incorporated by reference from Midcoast Registration Statement on Form S-1 (No. 333-27885) dated June 26, 1997).

10.16 Indemnity Agreement dated April 23, 1997 between Midcoast Energy Resources, Inc. and Richard N. Richards. (Incorporated by reference from Midcoast Registration Statement on Form S-1 (No. 333-27885) dated June 26, 1997)

10.17 Indemnity Agreement dated April 23, 1997 between Midcoast Energy Resources, Inc. and Duane S. Herbst. (Incorporated by reference from Midcoast Registration Statement on Form S-1 (No. 333-27885) dated June 26, 1997)

10.18 Indemnity Agreement dated April 23, 1997 between Midcoast Energy Resources, Inc. and Dan C. Tutcher. (Incorporated by reference from Midcoast Registration Statement on Form S-1 (No. 333-27885) dated June 26, 1997)

10.19 First Amendment to Credit Agreement dated May 30, 1997 by and between Bank One, Texas N.A. and Midcoast Energy Resources, Inc. , Magnolia Pipeline Corporation, H&W Pipeline Corporation, Magnolia Resources, Inc., Magnolia Gathering Inc., Midcoast Holdings No. One, Inc., Midcoast Gas Pipeline, Inc., Nugget Drilling Corporation, Midcoast Marketing, Inc., AlaTenn Energy Marketing Company, and Tennessee River Intrastate Gas Co. (Incorporated by reference from Midcoast Registration Statement on Form S-1 (No. 333-27885) dated June 26, 1997)

10.20 Second Amendment to Credit Agreement dated October 31, 1997 by and between Bank One, Texas N.A. and Midcoast Energy Resources, Inc. , Magnolia Pipeline Corporation, H&W Pipeline Corporation, Magnolia Resources, Inc., Magnolia Gathering Inc., Midcoast Holdings No. One, Inc., Midcoast Gas Pipeline, Inc., Nugget Drilling Corporation, Midcoast Marketing, Inc., AlaTenn Energy Marketing Company, Tennessee river Intrastate Gas Co., Mid Louisiana Gas Company, Mid Louisiana Gas Transmission Company and MIDLA Energy Services Company. (Incorporated by reference from Midcoast Form 8-K dated October 13, 1997).

10.21 First Amendment to Credit Agreement dated October 31, 1997 by and between Bank One, Texas N.A. and Midcoast Interstate Transmission, Inc. (f/k/a/ Alabama Tennessee Natural Gas Company). (Incorporated by reference from Midcoast Form 8-K dated October 13, 1997).

10.22 Third Amendment to Employment Agreement dated March 2, 1998 by and between Midcoast Energy Resources, Inc. and Dan Tutcher. (Incorporated by reference from Form 10-K/A dated February 2, 1999, for the fiscal year ended December 31, 1997).

10.23 Third Amendment to Employment Agreement dated March 18, 1998 by and between Midcoast Energy Resources, Inc. and I.J. Berthelot, II. (Incorporated by reference from Form 10-K/A dated February 2, 1999, for the fiscal year ended December 31, 1997).

10.24 Second Amendment to Employment Agreement dated March 18, 1998 by and between Midcoast Energy Resources, Inc. and Richard Robert. (Incorporated by reference from Form 10-K/A dated February 2, 1999, for the fiscal year ended December 31, 1997).

10.25 Amended and Restated Credit Agreement dated August 31, 1998, by and among Midcoast Energy Resources, Inc., and, Bank One Texas, N.A., CIBC Inc., and Nationsbank, N.A. (Incorporated by reference from Midcoast Form 10-Q for the nine month period ended September 30, 1998, as Exhibit 10.30).

10.26 First Amendment to the Amended and Restated Credit Agreement dated March 12, 1999, by and among Midcoast Energy Resources, Inc., and, Bank One Texas, N.A., CIBC Inc., and Nationsbank, N.A. (Incorporated by reference from Midcoast Form 10-K for the fiscal year ended December 31, 1998).

10.27 Amended and Restated Credit Agreement dated November 8, 1999, by and between Midcoast Energy Resources, Inc., Bank of America, N.A., individually and as administrative agent, Bank One, N.A., individually and as syndication agent, CIBC, Inc., individually and as documentation agent, Banc of America Securities LLC, as lead arranger and book manager, and certain other Lenders. (Incorporated by reference from Midcoast Form 8-K dated November 9, 1999 as Exhibit 10.4)

*10.28 First Amendment to the Amended and Restated Credit Agreement dated March 1, 2000, by and between Midcoast Energy Resources, Inc., Bank of America, N.A., individually and as administrative agent, Bank One, N.A., individually and as syndication agent, CIBC, Inc., individually and as documentation agent, Banc of America Securities LLC, as lead arranger and book manager, and certain other Lenders.

*21.1 Schedule listing subsidiaries of Midcoast Energy Resources, Inc.

*23.1 Consent of independent accountants, PricewaterhouseCoopers LLP

*23.2 Consent of independent accountants, Hein + Associates LLP

*27.1 Financial Data Schedule for the year ended December 31, 1999.

SIGNATURES

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

MIDCOAST ENERGY RESOURCES, INC.
(Registrant)

BY: /s/ DAN C. TUTCHER
Dan C. Tutcher
Chief Executive Officer

Date: March 31, 2000

In accordance with the Securities and Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

SIGNATURES	CAPACITY IN WHICH SIGNED
/s/ DAN C. TUTCHER (Dan C. Tutcher) Date: March 30, 2000	Chairman of the Board Chief Executive Officer and President
/s/ I. J. BERTHELOT, II (I. J. Berthelot, II) Date: March 30, 2000	Executive Vice President, Chief Operating Officer and Director
/s/ TED COLLINS, JR. (Ted Collins, Jr.) Date: March 30, 2000	Director
/s/ CURTIS J. DUFOUR III. (Curtis J. Dufour, III.) Date: March 30, 2000	Director
/s/ RICHARD N. RICHARDS (Richard N. Richards) Date: March 30, 2000	Director
/s/ RICHARD A. ROBERT (Richard A. Robert) Date: March 30, 2000	Treasurer, Principal Financial Officer Principal Accounting Officer
/s/ BRUCE WITHERS (Bruce Withers) Date: March 30, 2000	Director

EXHIBIT "A"
TO
FIRST AMENDMENT

CONSENT AND AGREEMENT

Each of Creole Gas Pipeline Corporation, a Delaware corporation, Dufour Petroleum, Inc. f/k/a DPI/Midcoast, Inc., a Mississippi corporation, H&W Pipeline Corporation, an Alabama corporation, Kansas Pipeline Company, a Kansas general partnership, Magnolia Gathering, Inc., an Alabama corporation, Magnolia Pipeline Corporation, an Alabama corporation, Magnolia Resources, Inc., a Mississippi corporation, MarGasCo Partnership, an Oklahoma general partnership, Midcoast Energy Marketing, Inc., a Delaware corporation, Midcoast Gas Services, Inc., a Delaware corporation, Midcoast Gas Pipeline, Inc., a Delaware corporation, Midcoast Gas Pipeline, Inc., a Texas corporation, Midcoast Holdings No. One, Inc., a Delaware corporation, Midcoast Interstate Transmission, Inc., an Alabama corporation, f/k/a Alabama Tennessee Natural Gas Co., Midcoast Kansas General Partner, Inc., a Delaware corporation, Midcoast Kansas Pipeline, Inc., a Delaware corporation, Midcoast Marketing, Inc., a Texas corporation, Mid Kansas Partnership, a Kansas general partnership, Mid Louisiana Gas Company, a Delaware corporation, Mid Louisiana Gas Transmission Company, a Delaware corporation, Nugget Drilling Corporation, a Minnesota corporation, Riverside Pipeline Company, L.P., a Kansas limited partnership, Southern Industrial Gas Corporation, a Louisiana corporation, and Tennessee River Intrastate Gas Company, Inc., an Alabama corporation, hereby consents to the provisions of this Amendment and the transactions contemplated herein, and hereby ratifies and confirms the Guaranty dated as of November 8, 1999 made by it for the benefit of Lenders, and agrees that its obligations and covenants thereunder are unimpaired hereby and shall remain in full force and effect.

IN WITNESS WHEREOF, each Guarantor has executed and delivered this Consent and Agreement.

GUARANTORS:

MAGNOLIA PIPELINE CORPORATION
H&W PIPELINE CORPORATION
MAGNOLIA RESOURCES, INC.
MAGNOLIA GATHERING, INC.
MIDCOAST HOLDINGS NO. ONE, INC.
TENNESSEE RIVER INTRASTATE
GAS COMPANY, INC.
NUGGET DRILLING CORPORATION
MIDCOAST MARKETING, INC.
MID LOUISIANA GAS COMPANY
CREOLE GAS PIPELINE CORPORATION
MID LOUISIANA GAS TRANSMISSION
COMPANY

MIDCOAST INTERSTATE
TRANSMISSION, INC.
MIDCOAST GAS SERVICES, INC.,
MIDCOAST ENERGY MARKETING,
INC.
DUFOUR PETROLEUM, INC. fka
DPI/MIDCOAST, INC.
MIDCOAST GAS PIPELINE, INC.,
a Texas corporation
MIDCOAST GAS PIPELINE, INC.,
a Delaware corporation
SOUTHERN INDUSTRIAL GAS
CORPORATION
MIDCOAST KANSAS PIPELINE, INC.
MIDCOAST KANSAS GENERAL
PARTNER, INC.

By: _____
Richard A. Robert
Treasurer

MID-KANSAS PARTNERSHIP
MARGASCO PARTNERSHIP
RIVERSIDE PIPELINE COMPANY, L.P.
KANSAS PIPELINE COMPANY

By: Midcoast Kansas General Partner, Inc.,
General Partner

By: _____
Richard A. Robert
Treasurer

EXHIBIT "B"
TO
FIRST AMENDMENT

ASSIGNMENT AND ACCEPTANCE

Reference is made to the Credit Agreement dated as of November 8, 1999 (the "Credit Agreement") among MIDCOAST ENERGY RESOURCES, INC., a Texas corporation (the "Borrower"), the Lenders (as defined in the Credit Agreement), Bank One, NA, as Syndication Agent, CIBC, Inc., as Documentation Agent, and Bank of America, N.A., as Administrative Agent for the Lenders (the "Administrative Agent"). Terms defined in the Credit Agreement are used herein with the same meaning.

The "Assignor" and the "Assignee" referred to on Schedule 1 agree as follows:

1. The Assignor hereby sells and assigns to the Assignee, without recourse and without representation or warranty except as expressly set forth herein, and the Assignee hereby purchases and assumes from the Assignor, an interest in and to the Assignor's rights and obligations under the Credit Agreement and the other Loan Documents as of the date hereof equal to the percentage interest specified on Schedule 1 of all outstanding rights and obligations under the Credit Agreement and the other Loan Documents. After giving effect to such sale and assignment, the Assignee's Commitment, Commitment Percentage, Percentage Share and the amount of the Loans owing to the Assignee will be as set forth on Schedule 1.

2. The Assignor: represents and warrants that it is the legal and beneficial owner of the interest being assigned by it hereunder and that such interest is free and clear of any adverse claim; makes no representation or warranty and assumes no responsibility with respect to any statements, warranties or representations made in or in connection with the Loan Documents or the execution, legality, validity, enforceability, genuineness, sufficiency or value of the Loan Documents or any other instrument or document furnished pursuant thereto; makes no representation or warranty and assumes no responsibility with respect to the financial condition of any Restricted Person or the performance or observance by any Restricted Person of any of its obligations under the Loan Documents or any other instrument or document furnished pursuant thereto; and attaches the Note held by the Assignor and requests that Administrative Agent exchange such Note for new Notes payable to the order of the Assignee in an amount equal to the Commitment assumed by the Assignee pursuant hereto and to the Assignor in an amount equal to the Commitment retained by the Assignor, if any, as specified on Schedule 1.

3. The Assignee confirms that it has received a copy of the Credit Agreement, together with copies of the financial statements referred to in Section 6.2 thereof and such other documents and information as it has deemed appropriate to make its own credit analysis and decision to enter into this Assignment and Acceptance; agrees that it will, independently and

without reliance upon Administrative Agent, the Assignor or any other Lender and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Credit Agreement; confirms that it is an Eligible Transferee; appoints and authorizes Administrative Agent to take such action as agent on its behalf and to exercise such powers and discretion under the Credit Agreement as are delegated to Administrative Agent by the terms thereof, together with such powers and discretion as are reasonably incidental thereto; agrees that it will perform in accordance with their terms all of the obligations that by the terms of the Credit Agreement are required to be performed by it as a Lender; and attaches any U.S. Internal Revenue Service or other forms required under Section 3.10(d).

4. Following the execution of this Assignment and Acceptance, it will be delivered to Administrative Agent for acceptance and recording by Administrative Agent. The effective date for this Assignment and Acceptance (the "Effective Date") shall be the date of acceptance hereof by Administrative Agent, unless otherwise specified on Schedule 1.

5. Upon such acceptance and recording by Administrative Agent, as of the Effective Date, the Assignee shall be a party to the Credit Agreement and, to the extent provided in this Assignment and Acceptance, have the rights and obligations of a Lender thereunder and the Assignor shall, to the extent provided in this Assignment and Acceptance, relinquish its rights and be released from its obligations under the Credit Agreement.

6. Upon such acceptance and recording by Administrative Agent, from and after the Effective Date, Administrative Agent shall make all payments under the Credit Agreement and the Notes in respect of the interest assigned hereby (including, without limitation, all payments of principal, interest and Unused Fees with respect thereto) to the Assignee. The Assignor and Assignee shall make all appropriate adjustments in payments under the Credit Agreement and the Notes for periods prior to the Effective Date directly between themselves.

7. This Assignment and Acceptance shall be governed by, and construed in accordance with, the Laws of the State of Texas.

8. This Assignment and Acceptance may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed shall be deemed to be an original and all of which taken together shall constitute one and the same agreement. Delivery of an executed counterpart of Schedule 1 to this Assignment and Acceptance by telecopier shall be effective as delivery of a manually executed counterpart of this Assignment and Acceptance.

IN WITNESS WHEREOF, the Assignor and the Assignee have caused Schedule 1 to this Assignment and Acceptance to be executed by their officers thereunto duly authorized as of the date specified thereon.

BANK OF AMERICA, N.A.,
Assignor

By: _____
Patrick M. Delaney
Managing Director

NEW LENDER,
Assignee

By: _____
Name:
Title:

SCHEDULE 1
to
ASSIGNMENT AND ACCEPTANCE

Commitment Percentage interest assigned: _____%

Assignee's Commitment: $_____

Aggregate outstanding principal amount of Loans assigned: $_____

Principal amount of Note payable to Assignee: $_____

Principal amount of Note payable to Assignor: $_____

Effective Date (if other than date of acceptance by Administrative Agent): *_____, 2000

BANK OF AMERICA, N.A.,
Assignor

By:_____
Patrick M. Delaney
Managing Director

Dated: _____, 19__

NEW LENDER, as Assignee

By: _____
Name:
Title:

Domestic Lending Office:

Eurodollar Lending Office:

* This date should be no earlier than five Business Days after the delivery of this Assignment and Acceptance to Administrative Agent.

Accepted and Approved **
this ___ day of _____, 2000

BANK OF AMERICA, N.A.,
as Administrative Agent

By: _____
Patrick M. Delaney
Managing Director

Accepted and Approved **
this ___ day of _____, 2000

BANK OF AMERICA, N.A.,
as LC Issuer

By: _____
Patrick M. Delaney
Managing Director

Approved this ____ day
of _____, 2000

MIDCOAST ENERGY RESOURCES, INC.

By: _____ **
Name:
Title:

** Required if the Assignee is an Eligible Transferee solely by reason of subsection (b) of the definition of "Eligible Transferee".

EXHIBIT 10.28

FIRST AMENDMENT TO AMENDED AND RESTATED CREDIT AGREEMENT

THIS FIRST AMENDMENT TO AMENDED AND RESTATED CREDIT AGREEMENT (herein called the "Amendment") made as of March 1, 2000 by and among MIDCOAST ENERGY RESOURCES, INC., a Texas corporation (herein called "Borrower"), BANK OF AMERICA, N.A., individually and as administrative agent (in its agency capacity herein called "Administrative Agent"), BANK ONE, NA, individually and as syndication agent (in its agency capacity herein called "Syndication Agent"), CIBC, INC., individually and as documentation agent (in its agency capacity herein called "Documentation Agent"), the Lenders party to the Original Agreement defined below ("Original Lenders"), and certain additional lenders as new Lenders ("New Lenders"; the New Lenders and the Original Lenders collectively called "Lenders"),

W I T N E S S E T H:

WHEREAS, Borrower, Administrative Agent, Syndication Agent, Documentation Agent and Original Lenders entered into that certain Amended and Restated Credit Agreement dated as of November 8, 1999 (as amended, supplemented, or restated prior to the date hereof, the "Original Agreement"), for the purpose and consideration therein expressed, whereby Original Lenders became obligated to make loans to Borrower as therein provided; and

WHEREAS, Borrower, Administrative Agent, Syndication Agent, Documentation Agent, Original Lenders and New Lenders desire to amend the Original Agreement to (i) increase the Facility Amount to , (ii) provide for certain additional lenders to become new Lenders, (iii) increase the LC Sublimit to $50,000,000, (iv) eliminate the C$50,000,000 limit on Canadian Dollar advances, and (v) amend various other provisions of the Original Agreement;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements contained herein and in the Original Agreement, in consideration of the loans which may hereafter be made by Lenders to Borrower, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto do hereby agree as follows:

ARTICLE I - Definitions and References

Section 1.1 Terms Defined in the Original Agreement. Unless the context otherwise requires or unless otherwise expressly defined herein, the terms defined in the Original Agreement shall have the same meanings whenever used in this Amendment.

Section 1.2 Other Defined Terms. Unless the context otherwise requires, the following terms when used in this Amendment shall have the meanings assigned to them in this Section 1.2.

"Amendment" means this First Amendment to Amended and Restated Credit Agreement.

"Amendment Documents" means this Amendment and the Consent and Agreement.

"Assignment and Acceptance" means the Assignment and Acceptance appended hereto as Exhibit "B".

"Consent and Agreement" means the Consent and Agreement appended hereto as Exhibit "A".

"Credit Agreement" means the Original Agreement as amended hereby.

"Revised Schedule of Commitments and Commitment Percentages" means the Revised Schedule of Commitments and Commitment Percentages appended hereto as Schedule 1.

ARTICLE II - Amendments to Original Agreement

Section 2.1 Cover Page. The figure "$265,000,000" on the cover page of the Original Agreement is hereby deleted and the figure "$335,000,000" is substituted therefore and the phrase "(including up to $50,000,000 Canadian Dollar Revolving Loan)" is hereby deleted.

Section 2.2 Defined Terms. (a) The definition of "Commitment" in Section 1.1 of the Original Agreement is hereby amended in its entirety to read as follows:

""Commitment" means initially the Dollar amount set forth opposite such Lender's name on its signature page hereto, and on and after the first and each successive assignment pursuant to Section 10.6(a), the Dollar amount set forth opposite such Lender's name on the Revised Schedule of Commitments and Commitment Percentages and as of the First Amendment Effective Date, the Revised Schedule of Commitments and Commitment Percentages appended as Schedule 1 to the First Amendment, as such Commitment may be reduced pursuant to Section 2.1, increased (as determined by such Lender in its sole and absolute discretion) pursuant to Section 2.14, or reduced or increased pursuant to Section 10.6."

(b) The definition of "Canadian Subsidiaries" in Section 1.1 of the Original Agreement is hereby amended in its entirety to read as follows:

""Canadian Subsidiaries" means collectively MCCI, MCOC and any other Subsidiary organized under the laws of Canada or any Province of Canada, acquired or formed by a Restricted Person in compliance with the terms and provisions of this Agreement, giving effect to such acquisition or formation, and "Canadian Subsidiary" individually means any of the foregoing."

(c) The definition of "Commitment Percentage" in Section 1.1 of the Original Agreement is hereby amended in its entirety to read as follows:

""Commitment Percentage" means initially the Commitment Percentage set forth opposite such Lender's name on its signature page hereto, and on and after the first and each successive assignment pursuant to Section 10.6(a), the Commitment Percentage set forth opposite such Lender's name on the Revised Schedule of Commitments and Commitment Percentages and on and after the First Amendment Effective Date, the Commitment Percentage set forth opposite such Lender's name on the Revised Schedule of Commitments and Commitment Percentages appended as Schedule 1 to the First Amendment, as such Commitment Percentage may be reduced pursuant to Section 2.1, increased (as determined by such Lender in its sole and absolute discretion) pursuant to Section 2.14, or reduced or increased pursuant to Section 10.6."

(d) The definition of "Facility Amount" in Section 1.1 of the Original Agreement is hereby amended in its entirety to read as follows:

""Facility Amount" means $335,000,000, subject to increase to $400,000,000 pursuant to Section 2.14 and subject to reduction pursuant to Section 2.1."

(e) The definition of "Indebtedness" in Section 1.1 of the Original Agreement is hereby amended by deleting section (c) thereof and substituting the following therefor:

"(c) Liabilities evidenced by a bond, debenture, note or similar instrument and Liabilities arising in connection with the Permitted Canadian Acquisition Indebtedness;"

(f) The definition of "LC Sublimit" in Section 1.1 of the Original Agreement is hereby amended in its entirety to read as follows:

""LC Sublimit" means a Dollar Equivalent amount equal to $50,000,000.

(g) The definition of "Permitted Canadian Investments" in Section 1.1 of the Original Agreement is hereby amended in its entirety to read as follows:

""Permitted Canadian Investments" means (without duplication) (a) equity Investments by Restricted Persons in Canadian Subsidiaries; provided that, after giving effect to the making by any Restricted Person of any equity Investment in a Canadian Subsidiary, the sum of (i) the Dollar Equivalent of the aggregate outstanding principal amount of all loans and advances made by all Restricted Persons to the Canadian Subsidiaries, plus (ii) the Dollar Equivalent of the aggregate amount of all equity Investments made by all Restricted Persons in the Canadian Subsidiaries, plus (iii) the Dollar Equivalent of the outstanding principal amount of the Permitted Canadian Acquisition Indebtedness, would not exceed forty percent (40%) of Borrower's Consolidated total assets, and (b) equity Investments by Restricted Persons in an aggregate amount not to exceed the Dollar Equivalent of $5,000,000 at any one time in non-Affiliate, non-Subsidiary Canadian companies or

partnerships engaged in the same or similar lines of business as Restricted Persons are engaged in or other businesses reasonably related thereto."

(h) The definition of "Permitted Liens" in Section 1.1 of the Original Agreement is hereby amended by amending subsection (h) of such definition in its entirety to read as follows:

"(h) Liens securing the KPC Notes and Liens securing (or an agreement to secure by Lien in the future) the Permitted Canadian Acquisition Indebtedness, but in the case of the Permitted Canadian Acquisition Indebtedness, such Liens can only encumber the specific assets acquired by MCOC or the MCOC Acquisition Subsidiary with proceeds of that specific Permitted Canadian Acquisition Indebtedness,"

(i) The definition of "Total Funded Debt" in Section 1.1 of the Original Agreement is hereby amended by amending the first sentence of such definition in its entirety to read as follows:

""Total Funded Debt" means, without duplication, all Indebtedness for money borrowed including any subordinated indebtedness, the KPC Notes, the Permitted Canadian Acquisition Indebtedness, purchase money mortgages, lease obligations capitalized in accordance with GAAP, amounts outstanding in respect of asset securitization vehicles, conditional sales contracts and similar title retention debt instruments, including any current maturities of such Indebtedness, plus the net present value of future operating lease payments calculated using standard S&P methodology, plus the redemption amount with respect to any redeemable preferred stock of Borrower or any Subsidiary required to be redeemed within the next twelve (12) months."

(j) The following definition of "Canadian Finance Subsidiary" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "Canadian Eurodollar Rate":

""Canadian Finance Subsidiary" means one or more wholly-owned Subsidiaries of Borrower, which Subsidiaries shall be corporations organized under the Business Corporation Act of the Province of Alberta or another Canadian Province and which Subsidiaries will purchase Permitted Canadian Acquisition Indebtedness from a Permitted Canadian Lender pursuant to the corresponding Put/Call Agreement."

(k) The following definition of "Canadian Side Letter Agreement" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "Canadian Finance Subsidiary":

""Canadian Side Letter" means a letter agreement to be entered into between the Administrative Agent and the Permitted Canadian Lender funding any Permitted Canadian Acquisition Indebtedness providing that while such Permitted Canadian

Acquisition Indebtedness remains outstanding (i) the Permitted Canadian Lender will not terminate the Put/Call Agreement without the prior written consent of Administrative Agent, (ii) the Permitted Canadian Lender will not amend, waive, modify or otherwise alter the terms of the Put/Call Agreement, and (iii) the Permitted Canadian Lender will agree to perform its contractual obligation under the "call" to sell such Permitted Canadian Acquisition Indebtedness to Borrower upon Borrower's exercise of its "call rights" even if for any reason the Put/Call Agreement had been breached or might otherwise not have been enforceable."

(l) The following definition of "First Amendment" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "Federal Funds Rate":

"First Amendment" means the First Amendment to this Agreement."

(m) The following definition of "First Amendment Effective Date" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "First Amendment":

"First Amendment Effective Date" means the first date on which all of the conditions precedent to the effectiveness of the First Amendment have been satisfied or waived."

(n) The following definition of "MCCI" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "Maximum Drawing Amount":

"MCCI" means Midcoast Canada Capital, Inc., a corporation organized under the Business Corporation Act of the Province of Alberta and wholly-owned Subsidiary of Borrower, which Subsidiary may acquire Permitted Canadian Acquisition Indebtedness from a Permitted Canadian Lender pursuant to the corresponding Put/Call Agreement."

(o) The following definition of "MCOC" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "MCCI":

"MCOC" means Midcoast Canada Operating Corporation, a corporation organized under the Business Corporation Act of the Province of Alberta and wholly-owned Subsidiary of Borrower, which Subsidiary may acquire certain Canadian assets and finance or refinance such acquisition by incurring Permitted Canadian Acquisition Indebtedness."

(p) The following definition of "MCOC Acquisition Subsidiary" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "MCOC":

"MCOC Acquisition Subsidiary" means one or more wholly-owned Subsidiaries of Midcoast Canada Operating Corporation, which Subsidiaries shall be corporations organized under the Business Corporation Act of the Province of

Alberta or another Canadian Province and which Subsidiaries will acquire certain Canadian assets and finance or refinance such acquisition by incurring Permitted Canadian Acquisition Indebtedness."

(q) The following definition of "1999 Canadian Financing Transaction" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "Net Worth":

""1999 Canadian Financing Transaction" means the C$15,187,500 term loan from First Chicago NBD Bank, Canada to MCOC dated March 24, 1999 to finance MCOC's acquisition of certain Canadian assets, which term loan was repaid and is no longer outstanding."

(r) The following definition of "Permitted Canadian Acquisition Indebtedness" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "Percentage Share":

""Permitted Canadian Acquisition Indebtedness" means, at any time, Indebtedness in Canadian Dollars for borrowed money:

(a) incurred by MCOC or an MCOC Acquisition Subsidiary;

(b) for the purpose of financing or refinancing MCOC's or such MCOC Acquisition Subsidiary's acquisition of assets located in Canada;

(c) payable to one or more Permitted Canadian Lenders; and

(d) in an amount which does not exceed the lesser of:

(i) (1) the Facility Amount less (2) the Dollar Equivalent of the Facility Usage plus (ii) the Dollar Equivalent of the amounts outstanding determined pursuant to subsections (a) through (c) above; and

(ii) $25,000,000;

provided, however, that after giving effect to such Permitted Canadian Acquisition Indebtedness, the sum of (i) the Dollar Equivalent of the outstanding principal amount of the Permitted Canadian Acquisition Indebtedness, plus (ii) the Dollar Equivalent of the aggregate amount of all equity Investments made by all Restricted Persons in the Canadian Subsidiaries, plus (iii) the Dollar Equivalent of the aggregate outstanding principal amount of all loans and advances made by all Restricted Persons to the Canadian Subsidiaries, would not exceed forty percent (40%) of Borrower's Consolidated total assets; provided further, to constitute Permitted Canadian Acquisition Indebtedness, such Indebtedness must be substantially similar in terms and substance to the 1999 Canadian Financing

Transaction, as determined by the Administrative Agent in its sole discretion including, without limitation, such Indebtedness being subject to a Put/Call Agreement in form and substance satisfactory to the Administrative Agent; and provided further, to constitute Permitted Canadian Acquisition Indebtedness, such Indebtedness must at all times be subject to a Canadian Side Letter Agreement."

(s) The following definition of "Permitted Canadian Lenders" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "Permitted Canadian Investments":

""Permitted Canadian Lenders" means those Canadian banking Affiliates of one or more Lenders who lend the Permitted Canadian Acquisition Indebtedness and enter into a Put/Call Agreement and Canadian Side Letter Agreement in connection therewith."

(t) The following definition of "Put/Call Agreement" is hereby added to Section 1.1 of the Original Agreement immediately following the definition of "Prior Credit Documents":

""Put/Call Agreement" means an agreement between the Permitted Canadian Lender and Borrower pursuant to which the Permitted Canadian Lender has the right to require that Borrower purchase the Permitted Canadian Acquisition Indebtedness subject to such Put/Call Agreement and Borrower has the right to require the Permitted Canadian Lender to sell to Borrower the Permitted Canadian Acquisition Indebtedness subject to such Put/Call Agreement."

Section 2.3. Amendments to Section 2.1. (a) The first and second sentences of Section 2.1 of the Original Agreement are hereby amended in their entirety to read as follows:

"Subject to the terms and conditions hereof, each Lender severally agrees to make Loans to Borrower upon Borrower's request from time to time during the Commitment Period; provided that (a) subject to Sections 3.3, 3.4 and 3.6, all Lenders are requested to make Loans of the same Type in accordance with their respective Percentage Shares and as part of the same Borrowing, (b) after giving effect to such Loans, the sum of (1) the Dollar Equivalent of the Facility Usage plus (2) the Dollar Equivalent of the Permitted Canadian Acquisition Indebtedness does not exceed the Facility Amount determined as of the date on which the requested Loans are to be made, and (c) after giving effect to such Loans, the Dollar Equivalent of such Lender's Loans and Percentage Share of any LC Obligations does not exceed such Lender's Commitment determined as of the date on which the requested Loans are to be made. The aggregate amount of all Loans in any Borrowing consisting of Base Rate Loans must be greater than or equal to $1,000,000 or must equal the remaining availability under the Facility Amount (or, if any Permitted Canadian Acquisition Indebtedness is outstanding, the remaining availability under the Facility Amount less the Permitted Canadian Acquisition Indebtedness) and the aggregate

amount of all Loans in any Borrowing consisting of Eurodollar Loans must be greater than or equal to $3,000,000."

(b) The last sentence of Section 2.1 of the Original Agreement is hereby amended in its entirety to read as follows:

"Borrower may, upon three (3) Business Days' prior written notice to Administrative Agent, irrevocably cancel all or any portion of the Unused Amount; provided, however, that Borrower may not cancel that portion of the Unused Amount equal to the outstanding principal balance of the Permitted Canadian Acquisition Indebtedness."

Section 2.4. Amendment to Section 2.3. The second sentence of Section 2.3 of the Original Agreement is hereby amended in its entirety to read as follows:

"If any Dollar Loan is converted into a Canadian Dollar Loan, the amount of the resulting Canadian Dollar Loan shall be equal to the Canadian Dollar Equivalent of such converted Dollar Loan; and, if any Canadian Dollar Loan is converted into a Dollar Loan, the amount of the resulting Dollar Loan shall be equal to the Dollar Equivalent of such converted Canadian Dollar Loan."

Section 2.5. Amendment to Section 2.7. Subsection 2.7(a) of the Original Agreement is hereby amended in its entirety to read as follows:

"(a) If at any time the sum of (1) the Dollar Equivalent of the Facility Usage plus (2) the Dollar Equivalent of the outstanding principal balance of the Permitted Canadian Acquisition Indebtedness exceeds the Facility Amount, Borrower shall immediately upon Administrative Agent's demand prepay the principal of the Loans in an amount at least equal to such excess."

Section 2.6. Amendment to Section 2.8. Subsection 2.8(a) of the Original Agreement is hereby amended in its entirety to read as follows:

"(a) the sum of (1) the Dollar Equivalent of the Facility Usage plus (2) the Dollar Equivalent of the outstanding principal balance of the Permitted Canadian Acquisition Indebtedness does not exceed the Facility Amount at such time;"

Section 2.7. Amendment to Section 2.13. The first sentence of Subsection 2.13(a) of the Original Agreement is hereby amended in its entirety to read as follows:

"If, after the making of all mandatory prepayments required under Section 2.7, the outstanding LC Obligations exceed the Facility Amount (or, if any Permitted Canadian Acquisition Indebtedness is outstanding, the outstanding LC Obligations exceed the Facility Amount less the Dollar Equivalent of the Permitted Canadian Acquisition Indebtedness), then in addition to prepayment of the entire principal

balance of the Loans Borrower will immediately pay to LC Issuer an amount equal to such excess."

Section 2.8. Amendment to Section 6.2. Section 6.2 of the Original Agreement is hereby amended by adding a new Subsection 6.2(g) thereto to read in its entirety as follows:

"(g) Not less than five (5) Business Days before MCOC or an MCOC Acquisition Subsidiary incurs any Permitted Canadian Acquisition Indebtedness, the Borrower will furnish a certificate stating the amount and terms of the Permitted Canadian Acquisition Indebtedness to be incurred, identifying the Permitted Canadian Lender(s) providing such Permitted Canadian Acquisition Indebtedness, identifying the assets to be acquired and the identity of the seller and certifying that after giving effect to such Indebtedness such Indebtedness will meet all of the conditions for such Indebtedness specified in the definition of "Permitted Canadian Acquisition Indebtedness."

Section 2.9. Amendment to Section 6.3. The second sentence of Subsection 6.3 of the Original Agreement is hereby amended in its entirety to read as follows:

"Each Restricted Person will permit representatives appointed by Administrative Agent (and after the occurrence and during the continuance of an Event of Default, representatives appointed by any Lender) (including independent accountants, auditors, agents, attorneys, appraisers and any other Persons) upon reasonable notice to visit and inspect during normal business hours any of such Restricted Person's property, including its books of account, other books and records, and any facilities or other business assets, and to make extra copies therefrom and photocopies and photographs thereof, and to write down and record any information such representatives obtain, and each Restricted Person shall permit Administrative Agent or its representatives (and after the occurrence and during the continuance of an Event of Default, any Lender or its representatives) to investigate and verify the accuracy of the information furnished to Administrative Agent or any Lender in connection with the Loan Documents, the Acquisition Agreement, the Permitted Canadian Acquisition Indebtedness and the KPC Notes and to discuss all such matters with its officers, employees and representatives."

Section 2.10. Amendment to Article VI. Article VI of the Original Agreement is hereby amended by adding a new Section 6.19 thereto to read in its entirety as follows:

"Section 6.19 Exercise of Call Rights. In connection with the Put/Call Agreement relating to any particular Permitted Canadian Acquisition Indebtedness, Borrower shall, upon demand of Administrative Agent, with the consent of Required Lenders, exercise Borrower's right to "call" such Permitted Canadian Acquisition Indebtedness and compel the Permitted Canadian Lender holding such Permitted Canadian Acquisition Indebtedness to sell, assign, transfer and convey such Permitted

Canadian Acquisition Indebtedness to Borrower pursuant to the terms of the applicable Put/Call Agreement."

Section 2.11. Amendment to Section 7.1. Subsection 7.1(e) of the Original Agreement is hereby amended in its entirety to read as follows:

"(e) inter-company Indebtedness (i) incurred by Borrower or any Guarantor and payable to Borrower or another Guarantor, or (ii) incurred by a Canadian Subsidiary and payable to Borrower, a Guarantor or another Canadian Subsidiary, including any extensions, renewals and replacements of any such inter-company Indebtedness; provided that the sum of (A) the Dollar Equivalent of the aggregate outstanding principal amount of all loans and advances made by Restricted Persons to Canadian Subsidiaries, plus (B) the Dollar Equivalent of the aggregate amount of all equity Investments made by Restricted Persons in Canadian Subsidiaries, plus (C) the Dollar Equivalent of the outstanding principal balance of the Permitted Canadian Acquisition Indebtedness does not exceed at any time during the term of this Agreement forty percent (40%) of Borrower's Consolidated total assets and Permitted Canadian Acquisition Indebtedness,"

Section 2.12. Amendment to Section 7.1. Subsection 7.1(i) of the Original Agreement is hereby amended by deleting the word "and" after the word "hereof" and a new subsection (k) is hereby added to Section 7.1 after the word "prices" and before the period at the end of subsection (j) to read in its entirety as follows:

"and (k) Permitted Canadian Acquisition Indebtedness."

Section 2.13. Amendment to Section 7.2. Subsection 7.2(f) of the Original Agreement is hereby amended to read in its entirety as follows:

"(f) guarantees, including, without limitation, the Put/Call Agreement, by a Restricted Person of Indebtedness of another Restricted Person permitted under Section 7.1."

Section 2.14. Amendment to Section 7.6. Subsection 7.6(f) of the Original Agreement is hereby amended in its entirety to read as follows:

"(f) without duplication of any amounts permitted pursuant to subsection (c) of this Section, loans or advances made by a Restricted Person to a Canadian Subsidiary; provided that, after giving effect to the making by any Restricted Person of any loan or advance to a Canadian Subsidiary, the sum of (A) the Dollar Equivalent of the aggregate outstanding principal amount of all loans and advances made by Restricted Persons to the Canadian Subsidiaries, plus (B) the Dollar Equivalent of the aggregate amount of all equity Investments made by Restricted Persons in the Canadian Subsidiaries, plus (C) the Dollar Equivalent of the outstanding principal balance of the Permitted Canadian Acquisition Indebtedness does not exceed at any time during

the term of this Agreement forty percent (40%) of Borrower's Consolidated total assets or"

Section 2.15. Amendment to Article VII. Article VII of the Original Agreement is hereby amended by adding a new Section 7.18 thereto to read in its entirety as follows:

"Section 7.18 Maintenance of Put/Call Agreement. Borrower shall not terminate any Put/Call Agreement relating to any particular Permitted Canadian Acquisition Indebtedness while such Permitted Canadian Acquisition Indebtedness is outstanding and held by a Permitted Canadian Lender."

Section 2.16. Amendment to Article VII. Article VII of the Original Agreement is hereby amended by adding a new Section 7.19 thereto to read in its entirety as follows:

"Section 7.19 Refinancing Permitted Canadian Acquisition Indebtedness. Borrower agrees that only MCCI or a Canadian Finance Subsidiary will acquire from Permitted Canadian Lenders any Permitted Canadian Acquisition Indebtedness and upon MCCI's or such Canadian Finance Subsidiary's acquisition of any such Indebtedness MCCI or such Canadian Finance Subsidiary shall not further sell, assign, transfer or convey such Indebtedness or any evidence of such Indebtedness."

Section 2.17. Amendment to Section 10.16. Subsection 10.16 of the Original Agreement is hereby amended by deleting the reference to the promissory note in the original principal amount of "$20,000,000" and substituting "$2,000,000" therefor.

ARTICLE III - Conditions of Effectiveness

Section 3.1. Effective Date. This Amendment shall become effective as of the date first above written when, and only when, (i) Administrative Agent shall have received, at Administrative Agent's office, a counterpart of this Amendment executed and delivered by Borrower and each Lender, (ii) Administrative Agent shall have additionally received the Consent and Agreement in the form attached hereto executed by each of the Guarantors, and (iii) Administrative Agent shall have additionally received the Assignment and Acceptance in the form attached hereto executed by each of the parties thereto.

ARTICLE IV - Waiver of Notice

Section 4.1. Waiver of Notice Required Under Section 2.14. Each Lender Party hereby waives the requirement that Borrower provide not less than thirty (30) days' prior written notice to Administrative Agent of any requested increase in the Facility Amount and agrees that this Amendment shall suffice as such written notice.

ARTICLE V - Representations and Warranties

Section 5.1. Representations and Warranties of Borrower. In order to induce each Lender to enter into this Amendment, Borrower represents and warrants to each Lender that:

(a) The representations and warranties contained in Article V of the Original Agreement are true and correct at and as of the time of the effectiveness hereof, except to the extent that the facts on which such representations and warranties are based have been changed by the extension of credit under the Credit Agreement and except as such representations and warranties have been modified pursuant to this Amendment.

(b) Borrower is duly authorized to execute and deliver this Amendment and is and will continue to be duly authorized to borrow monies and to perform its obligations under the Credit Agreement. Borrower has duly taken all corporate action necessary to authorize the execution and delivery of this Amendment and to authorize the performance of the obligations of Borrower hereunder.

(c) The execution and delivery by Borrower of this Amendment, the performance by Borrower of its obligations hereunder and the consummation of the transactions contemplated hereby do not and will not conflict with any provision of law, statute, rule or regulation or the certificate of incorporation or bylaws of Borrower, or of any material agreement, judgment, license, order or permit applicable to or binding upon Borrower, or result in the creation of (or obligation to create) any lien, charge or encumbrance upon any assets or properties of Borrower. Except for those which have been obtained, no consent, approval, authorization or order of any court or governmental authority or third party is required in connection with the execution and delivery by Borrower of this Amendment or to consummate the transactions contemplated hereby.

(d) When duly executed and delivered, each of this Amendment and the Original Agreement will be legal and binding obligations of Borrower, enforceable in accordance with their terms, except as limited by bankruptcy, insolvency or similar laws of general application relating to the enforcement of creditors' rights and by equitable principles of general application.

ARTICLE VI - Miscellaneous

Section 6.1. Ratification of Agreements. The Original Agreement as hereby amended is hereby ratified and confirmed in all respects. The Loan Documents, as they may be amended or affected by the various Amendment Documents, are hereby ratified and confirmed in all respects. Any reference to the Credit Agreement in any Loan Document shall be deemed to be a reference to the Original Agreement as hereby amended. The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of Lenders under the Credit Agreement, the Notes, or any other Loan Document nor constitute a waiver of any provision of the Credit Agreement, the Notes or any other Loan Document.

Section 6.2. Survival of Agreements. All representations, warranties, covenants and agreements of Borrower herein shall survive the execution and delivery of this Amendment and the performance hereof including, without limitation, the making or granting of the Loans, and shall

further survive until all of the Obligations are paid in full. All statements and agreements contained in any certificate or instrument delivered by Borrower or any Restricted Person hereunder or under the Credit Agreement to any Lender shall be deemed to constitute representations and warranties by, and/or agreements and covenants of, Borrower under this Amendment and under the Credit Agreement.

Section 6.3. Loan Documents. This Amendment is a Loan Document, and all provisions in the Credit Agreement pertaining to Loan Documents apply hereto.

Section 6.4. Revised Commitments and Commitment Percentages. Each of the Lenders agrees and acknowledges that upon the effectiveness of this Amendment, the Commitment and Commitment Percentage of each Lender will be as set forth on the Revised Schedule of Commitments and Commitment Percentages appended hereto as Schedule 1.

Section 6.5. Governing Law. This Amendment shall be governed by and construed in accordance with the laws of the State of Texas and any applicable laws of the United States of America in all respects, including construction, validity and performance.

Section 6.6. Counterparts; Fax. This Amendment may be separately executed in counterparts and by the different parties hereto in separate counterparts, each of which when so executed shall be deemed to constitute one and the same Amendment. This Amendment and the other Amendment Documents may be validly executed by facsimile or other electronic transmission.

THIS AMENDMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS OF THE PARTIES.

IN WITNESS WHEREOF, this Amendment is executed as of the date first above written.

MIDCOAST ENERGY RESOURCES, INC.,
Borrower

By: _____
Richard A. Robert
Chief Financial Officer and Treasurer

BANK OF AMERICA, N.A.,
Administrative Agent, Lender and LC Issuer

Signature Page 1

By: _____
Patrick M. Delaney
Managing Director

BANK ONE, NA,
Syndication Agent and Lender

By: _____
Name:
Title: Authorized Officer

CIBC INC.,
Documentation Agent and Lender

By: _____
Name:
Title:

FIRST UNION NATIONAL BANK,
Lender

By: _____
Name:
Title:

FLEET NATIONAL BANK,
Lender

By: _____
Name:
Title:

CREDIT AGRICOLE INDOSUEZ,
Lender

By: _____
Name:
Title:

By: _____
Name:
Title:

SCOTIABANC INC.,
Lender

By: _____
Name:
Title:

PRUDENTIAL SECURITIES CREDIT CORP.,
Lender

By: _____
Name:
Title:

UMB OKLAHOMA BANK,
Lender

By: _____
Name:
Title:

MEESPIERSON CAPITAL CORP.

By: _____
Darrell W. Holley
Managing Director

By: _____
Christopher S. Parada
Vice President

TORONTO DOMINION (TEXAS), INC.
Lender

By: _____
Name:
Title:

THE BANK OF TOKYO-MITSUBISHI, LTD.
Lender

By: _____
Name:
Title:

To Modcoast Energy Resources, Inc.
First Amendment

Signature Page 4

SCHEDULE 1

Revised Schedule of Commitments and Commitment Percentages

Commitment and Commitment Percentage		Lender
Commitment:	$40,000,000	BANK OF AMERICA, N.A.,
Commitment Percentage:	12%	Lender and LC Issuer
Percentage Share:	12%	
Commitment:	$40,000,000	BANK ONE, NA,
Commitment Percentage:	12%	Syndication Agent and Lender
Percentage Share:	12%	
Commitment:	$40,000,000	CIBC, INC.
Commitment Percentage:	12%	Documentation Agent and Lender
Percentage Share:	12%	
Commitment:	$40,000,000	FIRST UNION NATIONAL BANK,
Commitment Percentage:	12%	Lender
Percentage Share:	12%	
Commitment:	$30,000,000	PRUDENTIAL SECURITIES CREDIT
Commitment Percentage:	9%	CORP.
Percentage Share:	9%	Lender
Commitment:	$20,000,000	FLEET NATIONAL BANK
Commitment Percentage:	6%	Lender
Percentage Share:	6%	
Commitment:	$20,000,000	CREDIT AGRICOLE INDOSUEZ,
Commitment Percentage:	6%	Lender
Percentage Share:	6%	

To Modcoast Energy Resources, Inc.
First Amendment

Commitment:	$30,000,000	SCOTIABANC INC.
Commitment Percentage:	9%	Lender
Percentage Share:	9%	
Commitment:	$ 5,000,000	UMB OKLAHOMA BANK
Commitment Percentage:	1%	Lender
Percentage Share:	1%	
Commitment:	$20,000,000	MEESPIERSON CAPITAL CORP.
Commitment Percentage:	6%	Lender
Percentage Share:	6%	
Commitment:	$30,000,000	TORONTO DOMINION (TEXAS), INC.
Commitment Percentage:	9%	Lender
Percentage Share:	9%	
Commitment:	$20,000,000	THE BANK OF TOKYO-MITSUBISHI,
Commitment Percentage:	6%	LTD.
Percentage Share:	6%	Lender
TOTAL COMMITMENT	$335,000,000	

EXHIBIT 21.1

MIDCOAST ENERGY RESOURCES, INC AND SUBSIDIARIES

SUBSIDIARIES OF THE REGISTRANT

Name	Year of Incorporation	State of Incorporation	Ownership
Mid Louisiana Gas Company	1953	Delaware	100%
Creole Gas Pipeline Corporation	1962	Louisiana	100%
Midcoast Interstate Transmission, Inc.	1966	Alabama	100%
H&W Pipeline Corporation*	1976	Alabama	100%
Nugget Drilling Corporation*	1982	Minnesota	100%
Tennessee River Intrastate Gas Company, Inc.	1986	Alabama	100%
Mid Louisiana Gas Transmission	1987	Delaware	100%
Magnolia Pipeline Corporation	1989	Alabama	100%
Midcoast Marketing, Inc.	1991	Texas	100%
Midcoast Holdings No. One, Inc.	1993	Delaware	100%
Magnolia Resources, Inc.	1996	Mississippi	100%
Magnolia Gathering, Inc.	1996	Alabama	100%
Arcadia/Midcoast Pipeline of New York L.L.C.	1996	New York	50%
Midcoast Gas Pipeline, Inc.	1997	Texas	100%
Pan Grande Pipeline, L.L.C.	1996	Texas	70%
Starr County Gathering System - A Joint Venture	N/A	N/A	60%
Texana Gas Pipeline - A Joint Venture	N/A	N/A	50%
Midcoast Energy Marketing, Inc.	1998	Delaware	100%
Midcoast Gas Services, Inc.	1998	Delaware	100%
Midcoast Del Bajio S. de R.L. de C.V.	1998	Mexico	50%
Midcoast Canada Capital, Inc.	1999	Canada	100%
Midcoast Canada Operating Corporation	1999	Canada	100%
DPI/Midcoast, Inc.	1999	Mississippi	100%
Flare, LLC	1999	Alabama	100%
Nova Scotia Company	1999	Canada	100%
Alberta Limited Partnership	1999	Canada	1%
Midcoast Canada Energy Services, Inc.	1999	Canada	100%
Midcoasr Kansas Pipeline, Inc.	1999	Kansas	100%
Midcoast Kansas General Partner, Inc.	1999	Kansas	100%
MarGasCo Partnership	1999	Oklahoma	100%
Kansas Pipeline Company General Partnership	1999	Kansas	100%
Mid-Kansas General Partnership	1999	Kansas	100%
Riverside Pipeline Co. General Partnership	1999	Kansas	100%

* Presently Inactive

EXHIBIT 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-70371) and Form S-8 (No. 333-33127) of Midcoast Energy Resources, Inc. of our report dated March 10, 2000 relating to the consolidated financial statements and financial statement schedule, which appears in this Form 10-K.

PRICEWATERHOUSECOOPERS LLP

Houston, Texas
March 30, 2000

EXHIBIT 23.2

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-70371) and Form S-8 (No. 333-33127) of Midcoast Energy Resources, Inc. of our report dated March 18, 1999 relating to the consolidated financial statements and financial statement schedules, which appears in this Form 10-K.

HEIN + ASSOCIATES LLP

Houston, Texas
March 30, 2000

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==========

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

SCHEDULE 14A

Proxy Statement Pursuant to Section 14(a) of the Securities Exchange Act of 1934 (Amendment No.)

Filed by the Registrant [x]

Filed by a Party other than the Registrant [_]

Check the appropriate box:

[_] Preliminary Proxy Statement

[_] CONFIDENTIAL, FOR USE OF THE COMMISSION ONLY (AS PERMITTED BY RULE 14A-6(E)(2))

[x] Definitive Proxy Statement

[_] Definitive Additional Materials

[_] Soliciting Material Pursuant to (S) 240.14a-11(c) or (S) 240.14a-12

MIDCOAST ENERGY RESOURCES INC

(Name of Registrant as Specified In Its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (Check the appropriate box):

[x] No fee required.

[_] Fee computed on table below per Exchange Act Rules 14a-6(i)(4) and 0-11.

(1) Title of each class of securities to which transaction applies:

---

(2) Aggregate number of securities to which transaction applies:

---

(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (set forth the amount on which the filing fee is calculated and state how it was determined):

---

(4) Proposed maximum aggregate value of transaction:

---

(5) Total fee paid:

[_] Fee paid previously with preliminary materials.

[_] Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1) Amount Previously Paid:

---

(2) Form, Schedule or Registration Statement No.:

---

(3) Filing Party:

---

(4) Date Filed:

Notes:

Reg. (S) 240.14a-101.

SEC 1913 (3-99)

MIDCOAST ENERGY RESOURCES, INC.
1100 LOUISIANA, SUITE 2950
HOUSTON, TEXAS 77002

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS
TUESDAY, MAY 16, 2000
10:00 A.M. - CENTRAL TIME

MIDCOAST BOARD ROOM
1100 LOUISIANA, 32/nd/ FLOOR
HOUSTON, TEXAS 77002

On behalf of our board of directors, we cordially invite you to attend the 2000 Midcoast Energy Resources, Inc. Annual Meeting of Shareholders. At the meeting, we will:

1. Elect the board of directors;

2. Approve an amendment to the 1996 Incentive Stock Plan to increase the number of shares authorized for issuance under the plan by 468,750 shares of common stock to an aggregate of 1,000,000 shares;

3. Conduct other business properly brought before the meeting.

Shareholders who owned our common stock at the close of business on March 31, 2000 may attend and vote at the meeting. A shareholders' list will be available at our offices listed above for a period of ten days prior to the meeting. If you cannot attend the meeting, you may vote by mailing the proxy card in the enclosed postage-prepaid envelope. Any shareholder attending the meeting may vote in person, even though he or she has already returned a proxy card.

WHETHER OR NOT YOU EXPECT TO ATTEND THE MEETING, PLEASE COMPLETE, DATE, SIGN AND PROMPTLY RETURN THE PROXY IN THE ENCLOSED ENVELOPE. SHAREHOLDERS WHO ATTEND THE MEETING MAY REVOKE THEIR PROXIES AND VOTE IN PERSON.

You will notice that this year we have changed the format of the proxy statement to make it easier to understand. The Securities and Exchange Commission is encouraging companies to write documents for investors in plain English and we support this effort.

We look forward to seeing you at the meeting.

By order of the board of directors,

/s/ Duane S. Herbst

Duane S. Herbst
Secretary

Houston, Texas
April 17, 2000

U.S. SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

[X] Quarterly Report Under Section 13 or 15 (d) of the Securities Exchange Act of 1934 for the Quarterly Period Ended September 30, 2000

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

COMMISSION FILE NUMBER 0-8898

MIDCOAST ENERGY RESOURCES, INC.
(Exact name of Registrant as Specified in Its Charter)

TEXAS (State or Other Jurisdiction of Incorporation or Organization)	76-0378638 (I.R.S. Employer Identification No.)
1100 LOUISIANA, SUITE 2950 HOUSTON, TEXAS (Address of Principal Executive Offices)	77002 (Zip Code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE: (713) 650-8900

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No ___

On November 14, 2000 there were outstanding 12,491,684 shares of the Company's common stock, par value $.01 per share.

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
TABLE OF CONTENTS

Caption	Page
Glossary	iii
Part I. Financial Information	
Item 1. Condensed Consolidated Financial Statements	
Unaudited Condensed Consolidated Balance Sheets as of September 30, 2000 and December 31, 1999	1
Unaudited Condensed Consolidated Statements of Operations for the three months and nine months ended September 30, 2000 and September 30, 1999	2
Unaudited Condensed Consolidated Statements of Comprehensive Income for the three months and nine months ended September 30, 2000 and September 30, 1999	3
Unaudited Condensed Consolidated Statements of Cash Flows for the three months and nine months ended September 30, 2000 and September 30, 1999	4
Notes to Unaudited Condensed Consolidated Financial Statements	5
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations	11
Item 3. Quantitative and Qualitative Disclosures about Market Risk	19
Part II. Other Information	20
Signature	21

GLOSSARY

The following abbreviations, acronyms, or defined terms used in this Form10-Q are defined below:

Bbl.....	42 U.S. gallon barrel
Board.....	Board of directors of Midcoast Energy Resources, Inc.
Btu.....	British thermal unit
Common Stock.....	Midcoast common stock, par value $.01 per share
Company.....	Midcoast Energy Resources, Inc., its subsidiaries and affiliated companies
DPI.....	Dufour Petroleum, Inc., a wholly owned subsidiary of Midcoast Energy Resources, Inc.
EBITDA.....	Earnings Before Interest, Taxes, Depreciation and Amortization
EPS.....	Diluted earnings per share
FASB.....	Financial Accounting Standards Board
FERC.....	Federal Energy Regulatory Commission
KPC Acquisition.....	The November 1999 acquisition of Kansas Pipeline Company and MarGasCo
KPC System.....	A 1,120-mile interstate transmission pipeline
LIBOR.....	London Inter Bank Offering Rate
Mcf/day.....	Thousand cubic feet of gas (per day)
Midcoast.....	Midcoast Energy Resources, Inc.
MIDLA Acquisition.....	The October 1997 acquisition of the MLGC and MLGT Systems
MIT Acquisition.....	The May 1997 acquisition of the MIT and TRIGAS Systems
MIT System.....	A 288-mile interstate transmission pipeline
MLGC System.....	A 386-mile interstate transmission pipeline
MLGT System.....	A Louisiana intrastate pipeline
MMBtu.....	Million British thermal units
MMcf/day.....	Million cubic feet of gas (per day)
NGL.....	Natural gas liquid
NOL.....	Net operating loss
SeaCrest.....	SeaCrest Company, L.L.C., a 70% owned subsidiary of Mid Louisiana Gas Transmission Company, which is a wholly owned subsidiary of Midcoast Energy Resources, Inc.
SFAS.....	Statement of Financial Accounting Standards

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share data)

	September 30, 2000	December 31, 1999
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,487	$ 2,345
Accounts receivable, net of allowance of $1,180 and $1,484, respectively	82,463	55,189
Other current assets	6,336	4,905
Total Current Assets	92,286	62,439
PROPERTY, PLANT AND EQUIPMENT, NET	404,899	392,969
OTHER ASSETS	24,169	22,964
Total Assets	$521,354	$478,372
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES	$ 84,157	$ 63,978
LONG-TERM DEBT	249,397	240,000
OTHER LIABILITIES	2,079	2,147
DEFERRED INCOME TAXES	14,694	11,034
COMMITMENTS AND CONTINGENCIES (Note 3)	-	-
MINORITY INTEREST IN CONSOLIDATED SUBSIDIARIES	557	536
SHAREHOLDERS' EQUITY:		
Common stock, par value $.01 per share; authorized 31,250,000 shares; issued 12,732,359 and 12,721,980 shares, respectively	127	127
Paid-in capital	165,871	165,964
Retained earnings (accumulated deficit)	8,426	(2,915)
Accumulated other comprehensive income (loss)	(39)	71)
Treasury stock (at cost), 245,175 and 161,156 shares, respectively	(3,915)	(2,570)
Total Shareholders' Equity	170,470	160,677
Total Liabilities and Shareholders' Equity	$ 521,354	$ 478,372

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

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except share data)

	FOR THE THREE MONTHS ENDED		FOR THE NINE MONTHS ENDED	
	SEPTEMBER 30, 2000	SEPTEMBER 30, 1999	SEPTEMBER 30, 2000	SEPTEMBER 30, 1999
OPERATING REVENUES:				
Energy marketing revenue	$ 172,121	$ 90,852	$ 439,636	$ 240,294
Transportation fees	14,871	5,206	44,578	15,540
Natural gas processing revenue	10,037	5,269	26,726	10,376
Other	647	517	1,453	1,155
Total operating revenues	197,676	101,844	512,393	267,365
OPERATING EXPENSES:				
Energy marketing expenses	163,713	84,663	415,372	219,717
Natural gas processing costs	6,821	3,451	17,785	8,352
Other operating expenses	7,825	6,003	22,174	14,637
Depreciation, depletion and amortization	4,174	1,850	11,364	4,793
General and administrative	4,446	1,986	12,804	5,936
Total operating expenses	186,979	97,953	479,499	253,435
OPERATING INCOME	10,697	3,891	32,894	13,930
NON-OPERATING ITEMS:				
Interest expense	(5,328)	(775)	(14,951)	(3,651)
Minority interest in consolidated subsidiaries	(25)	(5)	(51)	(28)
Other income (expense), net	132	(23)	217	(115)
INCOME BEFORE INCOME TAXES	5,476	3,088	18,109	10,136
PROVISION FOR INCOME TAXES:				
Current	(69)	(497)	(472)	(1,326)
Deferred	(1,649)	167	(3,659)	(221)
NET INCOME	$ 3,758	$ 2,758	$ 13,978	$ 8,589
EARNINGS PER COMMON SHARE:				
BASIC	$ 0.30	$ 0.26	$ 1.12	$ 1.00
DILUTED	$ 0.30	$ 0.26	$ 1.10	$ 0.98
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:				
BASIC	12,477,698	10,559,172	12,504,058	8,585,037
DILUTED	12,725,235	10,795,517	12,728,533	8,804,258

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

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	FOR THE THREE MONTHS ENDED		FOR THE NINE MONTHS ENDED	
	SEPTEMBER 30, 2000	SEPTEMBER 30, 1999	SEPTEMBER 30, 2000	SEPTEMBER 30, 1999
Net income	$3,758	$2,758	$13,978	$8,589
Foreign currency translation adjustment	(112)	78	(110)	(68)
Comprehensive income	$3,646	$2,836	$13,868	$8,521

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

MIDCOAST ENERGY RESOURCES, INC., AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2000	September 30, 1999	September 30, 2000	September 30, 1999
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 3,758	$ 2,758	$ 13,978	$ 8,589
Adjustments to reconcile net income to net cash from operating activities:				
Depreciation, depletion and amortization	4,174	1,850	11,364	4,793
Deferred income taxes	1,649	(167)	3,659	221
Minority interest in consolidated subsidiaries	25	5	51	28
Gain on sale of plant assets	(101)	-	(101)	-
Other	(317)	72	(236)	36
Changes in working capital accounts, net of effects of acquisitions:				
(Increase) decrease in accounts receivable	(4,130)	2,164	(23,795)	(15,147)
(Increase) decrease in other current assets	857	(212)	(3,288)	(238)
Increase (decrease) in accounts payable and accrued liabilities	9,757	(12,455)	19,942	6,880
Net cash provided by (used in) operating activities	15,672	(5,985)	21,574	5,162
CASH FLOWS FROM INVESTING ACTIVITIES:				
Acquisitions	(300)	(3,998)	(13,320)	(34,388)
Capital expenditures	(3,786)	(3,040)	(10,205)	(14,788)
Proceeds from sale of plant assets	111	-	111	-
Net advances to equity investee	188	-	27	-
Other	(617)	(385)	(1,619)	(197)
Net cash used in investing activities	(4,404)	(7,423)	(25,006)	(49,373)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Bank debt borrowings	18,200	10,243	91,476	130,613
Bank debt repayments	(26,426)	(26)	(82,150)	(135,811)
Net proceeds from equity offering	-	-	-	54,583
Treasury stock purchases	(55)	-	(1,345)	(2,406)
Dividends on common stock	(879)	(747)	(2,639)	(1,668)
Other	(306)	(110)	(768)	168
Net cash provided by (used in) financing activities	(9,466)	9,360	4,574	45,479
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,802	(4,048)	1,142	1,268
CASH AND CASH EQUIVALENTS, beginning of period	1,685	5,516	2,345	200
CASH AND CASH EQUIVALENTS, end of period	$ 3,487	$ 1,468	$ 3,487	$ 1,468
SUPPLEMENTAL DISCLOSURES:				
Cash paid for interest	$ 7,257	$ 1,077	$ 15,655	$ 5,326
Cash paid for income taxes	$ -	$ 250	$ 1,600	$ 310

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

1. BASIS OF PRESENTATION:

The accompanying unaudited condensed consolidated financial information has been prepared by Midcoast in accordance with the instructions to Form 10-Q. The unaudited information furnished reflects all adjustments, all of which were of a normal recurring nature, which are, in the opinion of the Company, necessary for a fair presentation of the results for the interim periods presented. The condensed consolidated balance sheet at December 31, 1999 is derived from the audited financial statements. Although the Company believes that the disclosures are adequate to make the information presented not misleading, certain information and footnote disclosures, including significant accounting policies, normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to such rules and regulations. Certain reclassification entries were made with regard to the condensed consolidated financial statements for the periods presented in 1999 so that the presentation of the information is consistent with reporting for the condensed consolidated financial statements in 2000. It is suggested that the financial information be read in conjunction with the financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 1999.

2. ACQUISITIONS:

PROVOST ACQUISITION

In March 2000, the Company acquired the Provost natural gas plant and gathering system from NovaGas Canada LP, a division of TransCanada, for approximately $5.1 million (U.S.). The Provost acquisition includes 80 miles of natural gas gathering pipeline and a 15 MMcf/day sour gas processing plant and sour gas injection well. The system is located in east-central Alberta, Canada and is the only sour gas gathering and processing system in the area. The system is connected to 21 oil tank batteries and primarily gathers the associated sour gas production from approximately 900 wells in the Provost area. The acquisition was funded through the Company's existing credit facility.

MANYBERRIES ACQUISITION

In April 2000, the Company acquired the Manyberries Pipeline System from Triumph Energy Corporation for approximately $5.7 million (U.S.). The Manyberries acquisition consists of 80 miles of 6" and 10 miles of 4" crude oil pipeline that originates at the Manyberries Oil Field and terminates at an interconnection with the Milk River Pipeline system in southeast Alberta, Canada. Truck terminals, including the Legend terminal, and a significant amount of crude oil storage also contribute to the operations. The system has a design capacity of approximately 21,000 Bbls/day and transports light sour crude oil from the Manyberries oil field, as well as additional crude oil volumes from the Legend truck terminal. The pipeline system is the only light gravity system in southern Alberta and current volumes are approximately 6,500 Bbls/day. The acquisition was funded through the Company's existing credit facility.

3. COMMITMENTS AND CONTINGENCIES:

EMPLOYMENT CONTRACTS

Certain executive officers of the Company have entered into employment contracts, which through amendments provide for employment terms of varying lengths the longest of which expires in December 2002. These agreements may be terminated by mutual consent or at the option of the Company for cause, death or disability. In the event termination is due to death, disability or defined changes in the ownership of the Company, the full amount of compensation remaining to be paid during the term of the agreement will be paid to the employee or their estate, after discounting at 12% to reflect the current value of unpaid amounts.

MIT ACQUISITION CONTINGENCY

As part of the Company's MIT Acquisition, the Company has agreed to pay additional contingent annual payments, which will be treated as deferred purchase price adjustments, not to exceed $250,000 per year. The amount each year is dependent upon revenues received by the Company from certain gas transportation contracts. The contingency is due over an eight-year period commencing April 1, 1998 and payable at the end of each anniversary date. The Company is obligated to pay annually the lesser of 50% of the gross revenues received under these contracts or $250,000. Through September 30, 2000, the Company has made payments of $500,000 and has accrued an additional $125,000 under the contingency.

DPI ACQUISITION CONTINGENCY

As part of the DPI acquisition, the Company agreed that, in the event that the Company approves certain long-term DPI or Flare projects and these projects are placed under contract and in service, the Company would be obligated to pay the DPI shareholders additional consideration of up to $2.5 million. This contingency expires on March 11, 2002. As of September 30, 2000, none of the identified projects have been constructed and therefore no contingent payments have been accrued.

RATES AND REGULATORY MATTERS

Each of our transmission pipeline systems has contracts covering a portion of their firm transportation capacity with various terms of maturity, and each operates in different markets and regions with different competitive and regulatory pressures which can impact their ability to renegotiate and renew existing contracts, or enter into new long-term firm transportation commitments.

KPC filed a rate case pursuant to Section 4 of the NGA on August 27, 1999 (FERC Docket No. RP99-485-000). KPC's proposed rates reflect an annual revenue increase when compared to its initial FERC-approved rates. The rates have been protested by KPC's two principal customers and by the state public utility commissions that regulate them. On September 30, 1999, the FERC issued an order that set KPC's proposed rates for hearing and accepted and suspended the rates to be effective March 1, 2000, subject to possible refund. However, through September 30, 2000, KPC is continuing to charge its customers the initial FERC-approved rates. Additionally, the two customers have been paying only a portion of the Company's invoices pursuant to their protest of the current rates. The resultant unpaid balance from both customers at September 30, 2000 was approximately $432,000. The Section 4 rate case proceeding will determine whether the rates proposed by KPC for interstate transportation of natural gas are just and reasonable, and to the extent which KPC may recover all or any part of the proposed rate increase that it has not charged to its customers prior to approval. The hearing related to the proposed increase commenced on September 26, 2000 and concluded on October 20, 2000. A final Commission decision is not expected until at least the fourth quarter of 2001.

While we cannot predict with certainty the final outcome or timing of the resolution of rates and regulatory matters, the outcome of our current re-contracting and capacity subscription efforts, or the outcome of ongoing industry trends and initiatives, we believe the ultimate resolution of these issues will not have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

4. EARNINGS PER SHARE:

Basic and diluted earnings per share amounts are presented below for the three months and nine months ended September 30 (in thousands, except per share amounts):

	FOR THE THREE MONTHS ENDED SEPTEMBER 30, 2000					
	2000			1999		
	Net Income	Average Shares Outstanding	Earnings Per Share	Net Income	Average Shares Outstanding	Earnings Per Share
Basic	$3,758	12,478	$.30	$2,758	10,559	$.26
Effect of dilutive securities:						
Stock options	-	184	-	-	165	-
Warrants	-	63	-	-	72	-
Diluted	$3,758	12,725	$.30	$2,758	10,796	$.26

	FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2000					
	2000			1999		
	Net Income	Average Shares Outstanding	Earnings Per Share	Net Income	Average Shares Outstanding	Earnings Per Share
Basic	$13,978	12,504	$1.12	$8,589	8,585	$1.00
Effect of dilutive securities:						
Stock options	-	165	(.02)	-	156	(.02)
Warrants	-	60	-	-	63	-
Diluted	$13,978	12,729	$1.10	$8,589	8,804	$ .98

5. SEGMENT DATA:

The Company conducts its business of gathering, transporting, processing and marketing natural gas and other petroleum products through its transmission, end-user, and processing and gathering segments. The Company's operations are segregated into reportable segments based on the type of business activity and type of customer served. The Company's transmission pipelines primarily receive and deliver natural gas to and from other pipelines, and secondarily, provide end-user or gathering functions. Transportation fees are received by the Company for transporting natural gas owned by other parties through the Company's pipeline systems. The Company's end-user pipelines provide natural gas and natural gas transportation services to industrial customers, municipalities or electrical generating facilities through interconnect natural gas pipelines constructed or acquired by the Company. These pipelines provide a direct supply of natural gas to new industrial facilities or to existing facilities as an alternative to the local distribution company. The Company's processing and gathering systems typically consist of a network of pipelines which collect natural gas or crude oil from points near producing wells, process the natural gas, and transport oil and natural gas to larger pipelines for further transmission. The Company's natural gas processing revenues are realized from the extraction and sale of NGL's as well as the sale of the residual natural gas. In addition, the Company provides natural gas marketing services to its customers within each of the three segments. The Company's marketing activities include providing natural gas supply and sales services to some of its end-user customers by purchasing the natural gas supply from other marketers or pipeline affiliates and reselling the natural gas to the end-user. The Company also purchases natural gas directly from well operators on many of the Company's gathering systems and resells the natural gas to other marketers or pipeline affiliates. Many of the contracts pertaining to the Company's natural gas marketing activities are month-to-month spot market transactions with numerous gas suppliers or producers in the industry. The Company also offers other natural gas services to some of its customers including management of capacity release and gas balancing.

The Company evaluates each of its segments on a gross margin basis, which is defined as the revenues of the segment less related direct costs and expenses of the segment and does not include depreciation, depletion and amortization, interest or allocated corporate overhead. The "Other" column includes results of processing plant construction projects, which includes planning, fabrication, installation and facility operations and management as

well as general corporate items. The accounting policies of the segments are the same as those described in the Company's Annual Report on Form 10-K for the year ended December 31, 1999. The following tables present certain financial information relating to the Company's business segments as of or for the three months and nine months ended September 30, 2000 and 1999:

	AS OF OR FOR THE THREE MONTHS ENDED SEPTEMBER 30, 2000				
	Transmission Pipelines	End-User Pipelines	Gathering and Processing	Other	Total
	(In thousands)				
Revenues:					
Domestic	$ 64,312	$43,634	$ 87,822	$ 647	$196,415
Foreign	-	-	1,261	-	1,261
Total Revenues	64,312	43,634	89,083	647	197,676
Gross Margin	12,552	2,620	3,498	647	19,317
Depreciation, Depletion and Amortization	(2,018)	(277)	(1,601)	(278)	(4,174)
General and Administrative	-	-	-	(4,446)	(4,446)
Interest Expense	-	-	-	(5,328)	(5,328)
Other, net	-	-	-	107	107
Income before Income Taxes	10,534	2,343	1,897	(9,298)	5,476
Assets:					
Domestic	292,532	71,203	121,970	9,717	495,422
Foreign	-	-	25,932	-	25,932
Total Assets	292,532	71,203	147,902	9,717	521,354
Capital Expenditures (excluding acquisitions)	280	2,049	794	663	3,786

	AS OF OR FOR THE THREE MONTHS ENDED SEPTEMBER 30, 1999				
	Transmission Pipelines	End-User Pipelines	Gathering and Processing	Other	Total
	(In thousands)				
Revenues:					
Domestic	$25,530	$32,889	$ 42,372	$ 517	$101,308
Foreign	-	-	536	-	536
Total Revenues	25,530	32,889	42,908	517	101,844
Gross Margin	3,562	2,219	1,429	517	7,727
Depreciation, Depletion and Amortization	(352)	(251)	(1,126)	(121)	(1,850)
General and Administrative	-	-	-	(1,986)	(1,986)
Interest Expense	-	-	-	(775)	(775)
Other, net	-	-	-	(28)	(28)
Income before Income Taxes	3,210	1,968	303	(2,393)	3,088
Assets:					
Domestic	73,239	67,704	90,677	8,901	240,521
Foreign	-	-	14,563	-	14,563
Total Assets	73,239	67,704	105,240	8,901	255,084
Capital Expenditures (excluding acquisitions)	1,123	579	682	656	3,040

	FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2000				
	Transmission Pipelines	End-User Pipelines	Gathering and Processing	Other	Total
	(In thousands)				
Revenues:					
Domestic	$168,725	$117,441	$220,537	$ 1,453	$508,156
Foreign	-	-	4,237	-	4,237
Total Revenues	168,725	117,441	224,774	1,453	512,393
Gross Margin	33,813	6,647	15,149	1,453	57,062
Depreciation, Depletion and Amortization	(5,803)	(798)	(4,011)	(752)	(11,364)
General and Administrative	-	-	-	(12,804)	(12,804)
Interest Expense	-	-	-	(14,951)	(14,951)
Other, net	-	-	-	166	166
Income before Income Taxes	28,010	5,849	11,138	(26,888)	18,109
Capital Expenditures (excluding acquisitions)	775	4,906	3,113	1,411	10,205

	FOR THE NINE MONTHS ENDED SEPTEMBER 30, 1999				
	Transmission Pipelines	End-User Pipelines	Gathering and Processing	Other	Total
	(In thousands)				
Revenues:					
Domestic	$83,518	$90,999	$90,491	$ 1,155	$266,163
Foreign	-	-	1,202	-	1,202
Total Revenues	83,518	90,999	91,693	1,155	267,365
Gross Margin	10,154	5,825	7,525	1,155	24,659
Depreciation, Depletion and Amortization	(1,088)	(677)	(2,705)	(323)	(4,793)
General and Administrative	-	-	-	(5,936)	(5,936)
Interest Expense	-	-	-	(3,651)	(3,651)
Other, net	-	-	-	(143)	(143)
Income before Income Taxes	9,066	5,148	4,820	(8,898)	10,136
Capital Expenditures (excluding acquisitions)	5,967	4,431	3,251	1,139	14,788

6. NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED:

The FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" in June 1998. This Statement establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, (collectively referred to as derivatives) and for hedging activities. SFAS No. 133 will require the Company to record all derivatives on the balance sheet at fair value. If certain conditions are met, a derivative may be specifically designated as (a) a hedge of the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment, (b) a hedge of the exposure to variable cash flows of a forecasted transaction, or (c) a hedge of the foreign currency exposure of a net investment in a foreign operation, an unrecognized firm commitment, an available-for-sale security, or a foreign-currency denominated forecasted transaction. The accounting for the changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. The ineffective portion of a hedging derivative's change in fair value will be immediately recognized in earnings. The impact of SFAS No. 133 on the Company's financial statements will depend on a variety of factors, including future interpretative guidance from the FASB, the extent of the Company's hedging activities, the types of hedging instruments used and the effectiveness of such instruments. The standard was amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133", in June 1999 and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities", in June 2000 and is effective for fiscal years

beginning after June 15, 2000. The Company does not believe adoption of this pronouncement will materially effect the Company's consolidated financial position, results of operations or cash flows.

In December 1999, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin (SAB) No. 101, "Revenue Recognition in Financial Statements", to provide guidance for revenue recognition issues and disclosure requirements. Subsequently, the SEC issued SAB No. 101A, "Amendment: Revenue Recognition in Financial Statements", SAB No. 101B, "Second Amendment: Revenue Recognition in Financial Statements", which ultimately delayed implementation to the fourth quarter of fiscal years beginning after December 15, 1999. SAB No. 101 covers a wide range of revenue recognition topics and summarizes the staff's interpretations on the application of generally accepted accounting principles to revenue recognition. The Company does not believe this standard will have a material impact on the Company's consolidated financial position, results of operations or cash flows.

7. UNUSUAL CHARGE:

During the fourth quarter of 1999, the Company recorded a pre-tax unusual charge totaling $2.7 million ($2.2 million after tax) related to streamlining efforts announced in November 1999. The charge primarily relates to the severance and benefits of approximately 50 employees who were involuntarily terminated. The following table shows the status of, and changes to, the restructuring reserve for the first nine months of 2000.

Reserve at December 31, 1999.....	$ 1,701,009)
Expenditures.....	(1,568,009)
Reserve at September 30, 2000.....	$ 133,000

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements of the Company included elsewhere herein and with the Company's Annual Report on Form 10-K for the year ended December 31, 1999.

GENERAL

Since its formation, the Company has grown significantly as a result of the construction and acquisition of new pipeline facilities. From January 1996 through September 2000, the Company acquired or constructed 76 systems for an aggregate cost of approximately $384 million. The Company believes the historical results of operations do not fully reflect the operating efficiencies and improvements that are expected to be achieved by integrating the acquired and newly constructed pipeline systems. As the Company pursues its growth strategy in the future, its financial position and results of operations may fluctuate significantly from period to period.

The Company's results of operations are determined primarily by the volumes of natural gas transported, purchased and sold through its pipeline systems or processed at its processing facilities. With the exception of the Company's natural gas processing activities, whose margins fluctuate with commodity prices, the Company's revenues are derived from fee-based sources. In addition, most of the Company's operating costs do not vary directly with volumes on existing systems, thus, increases or decreases in transportation volumes generally have a direct effect on net income. The Company derives its revenues from three primary sources: (i) the marketing of natural gas and other petroleum products, (ii) transportation fees from pipeline systems owned by the Company and (iii) the processing of natural gas.

The Company's marketing revenues are realized through the purchase and resale of natural gas and other petroleum products to the Company's customers. Generally, gas marketing activities will generate higher revenues and correspondingly higher expenses than revenues and expenses associated with transportation activities, given the same volumes of natural gas. This relationship exists because, unlike revenues derived from transportation activities, gas marketing revenues and associated expenses include the full commodity price of the natural gas acquired. The operating income the Company recognizes from its gas marketing efforts is the difference between the price at which the natural gas was purchased and the price at which it was resold to the Company's customers. The Company's strategy is to focus its marketing activities on Company owned pipelines. The Company's marketing activities have historically varied greatly in response to market fluctuations.

Transportation fees are received by the Company for transporting natural gas or crude oil owned by other parties through the Company's pipeline systems, transport trucks and railcars. Typically, the Company incurs very little incremental operating or administrative overhead cost to transport natural gas through its pipeline assets, thereby recognizing a substantial portion of incremental transportation revenues as operating income.

The Company's natural gas processing revenues are realized from the extraction and sale of NGL's as well as the sale of the residual natural gas. These revenues occur under processing contracts with producers of natural gas utilizing both a "percentage of proceeds" and "keep-whole" basis. The contracts based on percentage of proceeds provide that the Company receives a percentage of the NGL's and residual natural gas revenues as a fee for processing the producer's natural gas. The keep-whole contracts require that the Company reimburse the producers for the Btu energy equivalent of the NGL's and fuel removed from the natural gas as a result of processing and the Company retains all revenues from the sale of the NGL's. The Company's processing margins can be adversely affected by declines in NGL prices, the relationship of NGL prices to natural gas prices, declines in natural gas throughput, or increases in shrinkage or fuel costs. In the case of keep-whole contracts, margins can be adversely affected by increases in natural gas prices. The Company uses over the counter swaps to hedge its physical exposure to processing spread risk. Processing spreads are the difference between the price the company receives for the sale of natural gas liquids and the price it pays for the natural gas equivalent on a heating value basis (MMBtu's). The Company has locked in a fixed processing spread on approximately 70% of its NGL production through December 2000.

The Company has had quarter-to-quarter fluctuations in its financial results in the past due to the fact that the Company's natural gas sales and pipeline throughputs can be affected by changes in demand for natural gas primarily because of the weather. In particular, demand on the Magnolia, MIT and MIDLA systems fluctuates due to weather variations because of the large municipal and other seasonal customers that are served by the respective systems. As a result, the winter months have historically generated more income than summer months on these systems. There can be no assurances that the Company's efforts to minimize such effects will have any impact on future quarter-to-quarter fluctuations due to changes in demand resulting from variations in weather conditions. Furthermore, future results could differ materially from historical

results due to a number of factors including, but not limited, to interruption or cancellation of existing contracts, the impact of competitive products and services, pricing of and demand for such products and services, and the presence of competitors with greater financial resources.

RESULTS OF OPERATIONS

The Company has acquired or constructed numerous pipelines since January 1996. The purchased assets were acquired from numerous sellers at different periods and all were accounted for under the purchase method of accounting for business combinations. Accordingly, the results of operations for such acquisitions are included in the Company's financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

For the three months ended September 30, 2000, the Company had total revenues of $197.7 million, a 94% increase, primarily driven by increases in commodity prices and acquisitions, from $101.8 million during the same period in 1999. Operating income improved 175% and net income improved 36% to $10.7 million and $3.8 million from $3.9 million and $2.8 million, respectively, in 1999. Diluted earnings per common share were $0.30 as compared to $0.26 per share in the third quarter of 1999. The Company's results for the past quarter were positively impacted by the addition of acquisition and expansion projects completed over the past year, strong throughput volume growth, particularly in the transmission and gathering/processing segments, along with improved processing margins due to higher commodity prices. These gains were partially offset by an increase in the Company's interest expense as a result of higher outstanding debt levels and an increase in its weighted average interest rate from 6.3% in the third quarter last year to 7.8% this year. Recently, the Company has taken steps to partially insulate itself from further interest rate increases by entering into a cancelable interest rate swap. Based on the Company's existing borrowing rate spreads, this swap effectively converts $100 million of floating rate debt to a fixed rate of 7.45% for a period of three years or until the counterparty cancels the swap at their option. Also impacting results during the past quarter was an increase in the Company's effective income tax rate to 31.4%, as compared to 10.7% last year due to the utilization of NOL carryforwards in prior periods and an 18% increase in the weighted average number of diluted common shares outstanding for the quarter resulting from the December 1999 public stock offering.

For the nine months ended September 30, 2000, the Company had total revenues of $512.4 million, a 92% increase, primarily driven by increases in commodity prices and acquisitions, from $267.4 million during the same period in 1999. Operating income improved 136% and net income improved 63% to $32.9 million and $14.0 million from $13.9 million and $8.6 million, respectively, in 1999. Diluted earnings per common share were $1.10 as compared to $0.98 per share for the nine months ended September 30, 1999. Variations for each segment are discussed in the segment results below.

SEGMENT RESULTS

The Company has segregated its business activities into three segments: Transmission Pipelines, End-User Pipelines, and Gathering Pipelines and Natural Gas Processing. The following tables present certain data for each of the segments for the three-month and nine-month periods ended September 30, 2000 and September 30, 1999. As previously discussed, the Company provides marketing services to its customers. For analysis purposes, the Company accounts for the marketing services by recording the marketing activity on the operating segment where it occurs. Therefore, the gross margin for each segment includes a transportation component and a marketing component. The Company evaluates each of its segments on a gross margin basis, which is defined as the revenues of the segment less related direct costs and expenses of the segment and does not include depreciation, depletion and amortization, interest or allocated corporate overhead.

TRANSMISSION PIPELINES

	FOR THE THREE MONTHS ENDED		FOR THE NINE MONTHS ENDED	
	September 30, 2000	September 30, 1999	September 30, 2000	September 30, 1999
	(In thousands, except amounts per MMBtu)			
OPERATING REVENUES:				
Energy Marketing Revenue	$55,369	$24,234	$141,059	$79,024
Transportation Fees	8,943	1,296	27,666	4,494
TOTAL OPERATING REVENUES	64,312	25,530	168,725	83,518
OPERATING EXPENSES:				
Energy Marketing Costs	50,018	20,832	129,311	69,764
Operating Expenses	1,742	1,136	5,601	3,600
TOTAL OPERATING EXPENSES	51,760	21,968	134,912	73,364
GROSS MARGIN	$12,552	3,562	$ 33,813	$10,154
VOLUME (in MMBtu)				
Marketing	13,857	10,156	40,708	35,940
Transportation	28,036	12,782	84,449	40,873
TOTAL VOLUME	41,893	22,938	125,157	76,813
GROSS MARGIN per MMBtu	$.30	$.16	$.27	$.13

THREE MONTHS ENDED SEPTEMBER 30, 2000 COMPARED TO THREE MONTHS ENDED SEPTEMBER 30, 1999

Gross margin for the three months ended September 30, 2000 increased 252% or $9.0 million over the same period in 1999 due to increases in transportation fees ($7.6 million) and marketing margins ($2.0 million) offset by increased operating expenses ($0.6 million). The $7.6 million increase in transportation fees was a result of the KPC acquisition in November 1999 and increased throughput volumes on the MIT system. The $2.0 million increase in marketing margins was a result of increased margins on the MIDLA system associated with new customers coming on-line in the third quarter 2000, increased throughput volumes on the Magnolia system and the MarGasCo acquisition in November 1999. The $0.6 million increase in operating expenses was a result of the KPC acquisition.

NINE MONTHS ENDED SEPTEMBER 30, 2000 COMPARED TO NINE MONTHS ENDED SEPTEMBER 30, 1999

Gross margin for the nine months ended September 30, 2000 increased 233% or $23.7 million over the same period in 1999 due to increases in transportation fees ($23.2 million) and marketing margins ($2.5 million) offset by increased operating expenses ($2.0 million). The $23.2 million increase in transportation fees was a result of the KPC acquisition in November 1999 and increased throughput volumes on the MIT system. The $2.5 million increase in marketing margins was a result of increased margins on the MIDLA system associated with new customers coming on-line in the third quarter 2000, increased throughput volumes on the Magnolia system and the MarGasCo acquisition in November 1999. The $2.0 million increase in operating expenses was a result of the KPC acquisition.

END-USER PIPELINES

	FOR THE THREE MONTHS ENDED		FOR THE NINE MONTHS ENDED	
	September 30, 2000	September 30, 1999	September 30, 2000	September 30, 1999
	(In thousands, except amounts per MMBtu)			
OPERATING REVENUES:				
Energy Marketing Revenue	$42,624	$32,071	$114,773	$88,415
Transportation Fees	1,010	818	2,668	2,584
TOTAL OPERATING REVENUES	43,634	32,889	117,441	90,999
OPERATING EXPENSES:				
Energy Marketing Costs	40,834	30,558	110,327	84,924
Operating Expenses	180	112	467	250
TOTAL OPERATING EXPENSES	41,014	30,670	110,794	85,174
GROSS MARGIN	$ 2,620	$ 2,219	$ 6,647	$ 5,825
VOLUME (in MMBtu)				
Marketing	11,723	12,927	37,225	36,285
Transportation	6,216	5,304	17,949	15,443
TOTAL VOLUME	17,939	18,231	55,174	51,728
GROSS MARGIN per MMBtu	$.15	$.12	$.12	$.11

THREE MONTHS ENDED SEPTEMBER 30, 2000 COMPARED TO THREE MONTHS ENDED SEPTEMBER 30, 1999

Gross margin for the three months ended September 30, 2000 increased 18% or $0.4 million over the same period in 1999 due to increases in transportation fees ($0.2 million) and marketing margins ($0.3 million) offset by increased operating expenses ($0.1 million). The $0.2 million increase in transportation fees was due to increased industrial demand and the full quarter operations of the Jummonville system. The $0.3 million increase in marketing margins was due to the full quarter operations of the Chevron system and increases in volumes on higher margin systems. The $0.1 million increase in operating expenses was due primarily to the Southern Industrial acquisition.

NINE MONTHS ENDED SEPTEMBER 30, 2000 COMPARED TO NINE MONTHS ENDED SEPTEMBER 30, 1999

Gross margin for the nine months ended September 30, 2000 increased 14% or $0.8 million over the same period in 1999 due to increases in transportation fees ($0.1 million) and marketing margins ($0.9 million) offset by increased operating expenses ($0.2 million). The $0.1 million increase in transportation fees was due to increased industrial demand and year-to-date operations of the Jummonville system. The $0.9 million marketing margin increase was due to the Chevron system and increases in volumes on higher margin systems. The $0.2 million increase in operating expenses was due primarily to the Southern Industrial acquisition.

GATHERING PIPELINES AND NATURAL GAS PROCESSING

	FOR THE THREE MONTHS ENDED		FOR THE NINE MONTHS ENDED	
	September 30, 2000	September 30, 1999	September 30, 2000	September 30, 1999
	(In thousands, except amounts per MMBtu)			
OPERATING REVENUES:				
Energy Marketing Revenue	$74,128	$34,547	$183,804	$72,855
Transportation Fees	4,918	3,092	14,244	8,462
Processing Revenues	10,037	5,269	26,726	10,376
TOTAL OPERATING REVENUES	89,083	42,908	224,774	91,693
OPERATING EXPENSES:				
Energy Marketing Costs	72,861	33,273	175,734	65,029
Operating Expenses	5,903	4,755	16,107	10,787
Processing Costs	6,821	3,451	17,784	8,352
TOTAL OPERATING EXPENSES	85,585	41,479	209,625	84,168
GROSS MARGIN	$ 3,498	$ 1,429	$ 15,149	$ 7,525
VOLUME (in MMBtu)				
Marketing	15,366	9,400	40,321	23,845
Transportation	35,320	23,609	95,975	66,398
Processing	4,195	3,063	11,752	7,104
TOTAL VOLUME	54,881	36,072	148,048	97,347
GROSS MARGIN per MMBtu	$ .06	$ .04	$ .10	$ .08

THREE MONTHS ENDED SEPTEMBER 30, 2000 COMPARED TO THREE MONTHS ENDED SEPTEMBER 30, 1999

Gross margin for the three months ended September 30, 2000 increased 145% or $2.1 million over the same period in 1999 due to increased processing margins ($1.4 million) and the earnings impact of acquisitions in the gathering and transportation areas ($1.8 million) offset by increases in operating expenses ($1.1 million). The $1.4 million increase in processing margins was due to increased volumes provided by the Gloria and Provost acquisitions and increased margins per MMBtu due to average increased NGL prices of $0.16 per gallon on percentage of proceeds contracts. The $1.8 million increase in transportation fees was due to increased throughput volumes provided by the Shelco, Manyberries and Seacrest acquisitions. The $1.1 million increase in operating expenses was due to the Shelco, Manyberries, Seacrest, Gloria and Colorado County acquisitions.

NINE MONTHS ENDED SEPTEMBER 30, 2000 COMPARED TO NINE MONTHS ENDED SEPTEMBER 30, 1999

Gross margin for the nine months ended September 30, 2000 increased 101% or $7.6 million over the same period in 1999. This increase was due primarily to the benefits of acquisitions in transportation and processing and increased NGL prices and processing spreads. Marketing margins, transportation fees and processing margins before operating expense increased by $12.9 million primarily due to increased volumes from the acquisitions of DPI and the Calmar facility in March 1999, several offshore gathering systems in mid third quarter 1999, and Provost, Shelco and Manyberries in 2000. In addition, processing spreads on our unhedged NGL production increased approximately $0.64 per MMBtu from the same period in 1999. The Company's NGL hedging activity also locked in 2000 spreads that were an average of $0.10 per MMBtu higher than processing spread levels for the first nine months of 1999. This was offset by an increase in operating expense of $5.3 million from the acquisitions discussed above.

OTHER INCOME, COSTS AND EXPENSES

Other revenues for the three and nine months ended September 30, 2000 increased to $0.6 million and $1.4 million, respectively, from $0.5 million and $1.2 million for the same periods in 1999. This increase was primarily attributable to an increase in income earned on processing plant construction projects, which includes planning, fabrication, installation and facility operations and management.

Depreciation, depletion and amortization for the three and nine months ended September 30, 2000 increased to $4.2 million and $11.4 million, respectively, from $1.9 million and $4.8 million for the same periods in 1999. This increase was primarily due to increased depreciation and amortization on assets acquired in the KPC, DPI/Flare, Calmar, Manyberries, and Provost acquisitions.

General and administrative expenses for the three and nine months ended September 30, 2000 increased to $4.4 million and $12.8 million, respectively from $2.0 million and $5.9 million for the same periods in 1999. The increase was due to increased costs associated with the management of the assets acquired in the KPC, DPI/Flare and Calmar acquisitions. General and administrative expenses, as a percentage of gross margin, decreased to 22% for the nine months ended September 30, 2000 from 24% for the same period in 1999.

Interest expense for the three and nine months ended September 30, 2000 increased to $5.3 million and $15.0 million from $1.0 million and $3.7 million, respectfully, for the same periods in 1999. This increase was due to an increase in the debt level as well as an increase in the weighted average interest rate. The Company was servicing an average of $258.5 million and $256.0 million in debt for the three and nine months ended September 30, 2000 as compared to $66.7 million and $86.9 million in debt for the same periods in 1999. The increased debt level in 2000 was primarily associated with the debt used to finance the Company's KPC acquisition in November 1999. The Company's weighted average interest rate for the three and nine months ended September 30, 2000 increased to 7.8% respectively, from 6.3% for the same periods in 1999.

INCOME TAXES

The Company's income tax provision for the three and nine months ended September 30, 2000 increased to $1.7 million and $4.1 million, respectively, from $0.3 million and $1.5 million in 1999. The Company's effective tax rate for the three and nine months ended September 30, 2000 increased to 31.4% and 22.8%, respectively, from 10.7% and 15.3% in 1999 due to the utilization of NOL carryforwards in prior periods. The effective tax rate for the remainder of 2000 is expected to be closer to the federal statutory rate of 34%.

As of September 30, 2000, the Company has NOL carryforwards of approximately $12.4 million, expiring in various amounts from 2004 through 2018. The ability of the Company to utilize the carryforwards is dependent upon the Company generating sufficient taxable income and will be affected by limitations (currently estimated at $6.0 million) on the use of such carryforwards for 2000 due to a change in shareholder control under section 382 of the Internal Revenue Code created by the acquisitions of Republic and DPI.

RATES AND REGULATORY MATTERS

Each of our transmission pipeline systems has contracts covering a portion of their firm transportation capacity with various terms of maturity, and each operates in different markets and regions with different competitive and regulatory pressures which can impact their ability to renegotiate and renew existing contracts, or enter into new long-term firm transportation commitments.

KPC filed a rate case pursuant to Section 4 of the NGA on August 27, 1999 (FERC Docket No. RP99-485-000). KPC's proposed rates reflect an annual revenue increase when compared to its initial FERC-approved rates. The rates have been protested by KPC's two principal customers and by the state public utility commissions that regulate them. On September 30, 1999, the FERC issued an order that set KPC's proposed rates for hearing and accepted and suspended the rates to be effective March 1, 2000, subject to possible refund. However, through September 30, 2000, KPC is continuing to charge its customers the initial FERC-approved rates. Additionally, the two customers have been paying only a portion of the Company's invoices pursuant to their protest of the current rates. The resultant unpaid balance from both customers at September 30, 2000 was approximately $432,000. The Section 4 rate case proceeding will determine whether the rates proposed by KPC for interstate transportation of natural gas are just and reasonable, and to the extent which KPC may recover all or any part of the proposed rate increase that it has not charged to its customers prior to approval. The hearing related to the

proposed increase commenced on September 26, 2000 and concluded on October 20, 2000. A final Commission decision is not expected until at least the fourth quarter of 2001.

While we cannot predict with certainty the final outcome or timing of the resolution of rates and regulatory matters, the outcome of our current re-contracting and capacity subscription efforts, or the outcome of ongoing industry trends and initiatives, we believe the ultimate resolution of these issues will not have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

CAPITAL RESOURCES AND LIQUIDITY

Since 1996, the Company has acquired approximately $384 million of pipeline systems. Capital requirements have been funded through equity infusions from common stock offerings, borrowings from various commercial banks and cash flow from operations.

The Company has raised net proceeds of approximately $128 million in four common stock offerings since being listed on the American Stock Exchange in August 1996. These capital infusions and the stability of our cash flow has allowed the Company the financial flexibility to utilize lower cost conventional bank debt financing to fund a large part of its growth. The Company's long-term debt to total capitalization ratio increased to 59% at September 30, 2000 from 33% at September 30, 1999.

In November 1999, March 2000 and again in June 2000, the Company amended and restated its bank financing agreement under the certain Amended and Restated Credit Agreement dated August 31, 1998. The amendments added additional banks to the syndicate, increased our borrowing availability, modified our letter of credit facility, extended the maturity five years to November 2004, modified financial covenants, established waiver and amendment approvals, and changed the method to determine the interest rate to be charged.

The amendments to the credit agreement increased our borrowing availability from $125 million to $300 million, with a provision to increase up to $400 million. The amended credit agreement provides borrowing availability as follows: (i) up to a $50 million sublimit for the issuance of standby and commercial letters of credit and (ii) the difference between the $300 million and the used sublimit available as a revolving credit facility. At the option of the Company, borrowings under the amended credit agreement accrue interest at LIBOR plus an applicable margin or the higher of the Bank of America prime rate or the Federal Funds (base rate borrowings) rate plus an applicable margin.

The applicable margin percentage to be added to the interest rate is based on the Company's debt to total capitalization ratio at the end of the previous fiscal quarter. The Company is charged a margin between 1.0% and 1.75% on LIBOR based borrowings and between 0.0% and 0.25% on base rate borrowings as the Company's total debt to total capitalization ratio ranges at or below 40% up to 65%, respectively. The Company is currently being charged margins of 1.5% on LIBOR borrowings and no margin on base rate borrowings.

The credit agreement is secured by all accounts receivable, contracts, and the pledge of all of our subsidiaries' stock and a first lien security interest in our pipeline systems. It also contains a number of customary covenants that require us to maintain certain financial ratios and limit our ability to incur additional indebtedness, transfer or sell assets, create liens, or enter into a merger or consolidation. At September 30, 2000, the Company had approximately $50.6 million of available capacity under its credit agreement.

The Company believes that its credit agreement and funds provided by operations will be sufficient to meet its operating cash needs for the foreseeable future and its projected capital expenditures, other than acquisitions.

If sufficient funds under the credit agreement are not available to fund acquisition and construction projects, the Company would seek to obtain such financing from the sale of equity securities or other debt financing. There can be no assurances that any such financing will be available on terms acceptable to the Company. Should sufficient capital not be available, the Company will not be able to implement its growth strategy in as aggressive a manner as currently planned.

ENVIRONMENTAL AND SAFETY MATTERS

Our activities in connection with the operation and construction of pipelines and other facilities for transporting, processing, treating, or storing natural gas and other products are subject to environmental and safety regulation by numerous federal, state, local and Canadian authorities. This regulation can include ongoing oversight regulation as well as requirements

for construction or other permits and clearances that must be granted in connection with new projects or expansions. Regulatory requirements can increase the cost of planning, designing, initial installation and operation of such facilities. Sanctions for violation of these requirements include a variety of civil and criminal enforcement measures, including assessment of monetary penalties, assessment and remediation requirements and injunctions as to future compliance. The following is a discussion of certain environmental and safety concerns that relate to us. It is not intended to constitute a complete discussion of the various federal, state, local and Canadian statutes, rules, regulations, or orders to which our operations may be subject.

In most instances, these regulatory requirements relate to the release of substances into the environment and include measures to control water and air pollution. Moreover, we could incur liability under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, or state counterparts, regardless of our fault, in connection with the disposal or other releases of hazardous substances, including those arising out of historical operations conducted by our predecessors. Further, the recent trend in environmental legislation and regulations is toward stricter standards, and this trend will likely continue in the future.

Environmental laws and regulations may also require us to acquire a permit before we may conduct certain activities. Further, these laws and regulations may limit or prohibit activities on certain lands lying within wilderness areas, wetlands, areas providing habitat for certain species that have been identified as "endangered" or "threatened" or other protected areas. We are also subject to other federal, state and local laws covering the handling, storage or discharge of materials, and we are subject to laws that otherwise relate to the protection of the environment, safety and health. As an employer, we are required to maintain a workplace free of recognized hazards likely to cause death or serious injury and to comply with specific safety standards.

We will make expenditures in connection with environmental matters as part of our normal operations and capital expenditures. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that might become necessary. We are subject to an inherent risk of incurring environmental costs and liabilities because of our handling of oil, gas and petroleum products, historical industry waste disposal practices and prior use of gas flow meters containing mercury. There can be no assurance that we will not incur material environmental costs and liabilities. Management believes, based on our current knowledge, that we have obtained and are in current compliance with all necessary and material permits and that we are in substantial compliance with applicable material environmental and safety regulations. Further, we maintain insurance coverages that we believe are customary in the industry; however, there can be no assurance that our environmental impairment insurance will provide sufficient coverage in the event an environmental claim is made against us. We are not aware of any existing environmental or safety claims that would have a material impact upon our financial position, results of operations or cash flows.

NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

See Note 6, which is incorporated herein by reference.

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

This Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in and incorporated by reference into this Form 10-Q are forward-looking statements. These forward looking statements include, without limitation, statements under "Management's Discussion and Analysis of Financial Condition and Results of Operations--Capital Resources and Liquidity" regarding the Company's estimate of the sufficiency of existing capital resources, whether funds provided by operations will be insufficient to meet its operational needs in the foreseeable future, and its ability to use NOL carryforwards prior to their expiration. Although, we believe that the expectations reflected in these forward looking statements are reasonable, we can not give any assurance that such expectations reflected in these forward looking statements will prove to have been correct.

When used in this Form 10-Q, the words "expect", "anticipate", "intend", "plan", "believe", "seek", "estimate", and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations", and elsewhere in this Form 10-Q.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. Before you invest in our common stock, you should be aware that the occurrence of any of the events described in "Risk Factors" in the Prospectus Supplement, dated December 6, 1999 and elsewhere in this Form 10-Q could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common stock could decline, and you could lose all or part of your investment.

We cannot guarantee any future results, levels of activity, performance or achievements. Except as required by law, we undertake no obligation to update any of the forward-looking statements in this Form 10-Q after the date of this Form 10-Q.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company utilizes derivative financial instruments to manage market risks associated with certain energy commodities and interest rates. According to guidelines provided by the Board, the Company enters into exchange-traded commodity futures, options and swap contracts to reduce the exposure to market fluctuations in price and transportation costs of energy commodities and fluctuations in interest rates. The Company does not engage in speculative trading. Approvals are required from senior management prior to the execution of any financial derivative.

COMMODITY PRICE RISK

The Company's commodity price risk exposure arises from inventory balances and fixed price purchase and sale commitments. The Company uses exchange-traded commodity futures contracts and swap contracts to manage and hedge price risk related to these market exposures. The futures contracts have pricing terms indexed to the New York Mercantile Exchange.

The company also uses over-the-counter swaps to hedge its physical exposure to processing spread risk. Processing spreads are the difference between the price the company receives for the sale of natural gas liquids and the price it pays for the natural gas equivalent on a heating value basis (MMBtu's). The company has locked in a fixed processing spread on approximately 70% of its NGL production through December 2000.

The gains, losses and related costs of the financial instruments that qualify as a hedge are not recognized until the underlying physical transaction occurs.

INTEREST RATE RISK

The Company's Credit Facility provides an option for the Company to borrow funds at a variable interest rate of LIBOR plus an applicable margin based on the Company's debt to total capitalization ratio. In an effort to mitigate interest rate fluctuation exposure, the Company entered into interest rate swaps under three separate swap agreements with a combined notional amount of $165 million dollars. The interest rate swap agreements entered into by the Company effectively convert $165 million of floating-rate debt to fixed-rate debt.

The first interest rate swap agreement was entered into with Bank One in December 1997. The swap agreement effectively established a fixed interest rate setting of 6.02% for a two-year period on a notional amount of $25 million. This swap agreement was subsequently transferred to Bank of America in November 1998 and replaced with a new swap agreement. The new swap agreement provides a fixed 5.09% interest rate to the Company with a new two year termination date of December 2000 which may, however, be extended through December 2003 at Bank of America's option on the last day of the initial term. The variable three-month LIBOR rate is reset quarterly based on the prevailing market rate and the Company is obligated to reimburse Bank of America when the three-month LIBOR rate is reset below 5.09%. Conversely, Bank of America is obligated to reimburse the Company when the three-month LIBOR rate is reset above 5.09%. At September 30, 2000 and 1999, the fair value of this interest rate swap through the initial termination date was a net asset of approximately $95,539 and a net liability of approximately $199,642, respectively.

The second interest rate swap agreement was entered into with CIBC in October 1998. The swap agreement effectively established a fixed interest rate setting of 4.475% for a three-year period on a notional amount of $40 million. The agreement, however, may be extended an additional two years through November 2003 at CIBC's option on the last day of the initial term. The variable three-month LIBOR rate is reset quarterly based on the prevailing market rate and the Company is obligated to reimburse CIBC when the three-month LIBOR rate is reset below 4.475%. Conversely, CIBC is obligated to

reimburse the Company when the three-month LIBOR rate is reset above 4.475%. At September 30, 2000 and 1999, the fair value of this interest rate swap through the initial termination date was a net asset of approximately $1,046,963 and $1,363,317, respectively.

The effect of these swap agreements was to lower interest expense by $961,511 and $182,501 in the nine months ended September 30, 2000 and 1999, respectively.

A third interest rate swap agreement was entered into with Scotiabank in October 2000. The swap agreement effectively established a fixed interest rate setting of 5.95% for a three-year period beginning October 2000 on a notional amount of $100 million. The agreement is cancelable at Scotiabank's option at the end of any three-month period during the three-year term with 2 days notice. The variable three-month LIBOR rate is reset quarterly based on the prevailing market rate and the company is obligated to reimburse Scotiabank when the three-month LIBOR rate is reset below 5.95%. Conversely, Scotiabank is obligated to reimburse the Company when the three-month LIBOR rate is reset above 5.95%.

PART II. OTHER INFORMATION

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

a. Exhibits:

None

b. Reports on Form 8-K:

None

SIGNATURE

In accordance with the requirements of the Exchange Act, the Registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MIDCOAST ENERGY RESOURCES, INC.
(Registrant)

BY: /s/ Richard A. Robert

Richard A. Robert
Principal Financial Officer
Treasurer
Principal Accounting Officer

Date: November 14, 2000

MIDCOAST ENERGY RESOURCES, INC.
1100 LOUISIANA, SUITE 2950
HOUSTON, TEXAS 77002

PROXY STATEMENT

ANNUAL MEETING OF SHAREHOLDERS
MAY 16, 2000

INFORMATION CONCERNING SOLICITATION AND VOTING

Our board of directors is soliciting proxies for the 2000 Annual Meeting of Shareholders to be held on Tuesday, May 16, 2000 at 10:00 a.m. (Houston time) in our boardroom located at 1100 Louisiana, 32/nd/ Floor, Houston, Texas 77002, and at any adjournments or postponements of the meeting. This proxy statement contains important information for you to consider when deciding how to vote on the matters brought before the meeting. Please read it carefully.

Midcoast will pay the costs of soliciting proxies from shareholders. Directors, officers and regular employees may solicit proxies on behalf of Midcoast, without additional compensation, personally or by telephone. Voting materials, which include the proxy statement, proxy card and 2000 Annual Report, will be mailed to shareholders on or about April 17, 2000.

QUESTIONS AND ANSWERS

Q: Who can attend and vote at the meeting?

A: You can attend and vote at the meeting if you were a shareholder at the close of business on the record date, March 31, 2000. On that date, there were 12,494,124 shares outstanding and entitled to vote at the annual meeting.

Q: What am I voting on?
A: You are voting on:

- The election of directors; and
- The approval of an amendment to the 1996 Incentive Stock Plan.

The six individuals receiving the highest number of "FOR" votes will be elected to the board of directors. The approval of the amendment to the 1996 Incentive Stock Plan requires the affirmative "FOR" vote of a majority of the shares present at the meeting and entitled to vote.

Q: How will the proxies vote on any other business brought up at the meeting?

A: By submitting your proxy card, you authorize the proxies to use their judgment to determine how to vote on any other matter brought before the meeting. We do not know of any other business to be considered at the meeting.

The proxies' authority to vote according to their judgment applies only to shares you own as a shareholder of record.

Q: How do I cast my vote?

A: If you hold your shares as a shareholder of record, you can vote in person at the annual meeting or you can vote by mail. If you are a street-name shareholder, you will receive instructions from your bank, broker or other nominee describing how to vote your shares.

The enclosed proxy card contains instructions for mail voting. The proxies identified on the back of the proxy card will vote the shares of which you are the shareholder of record in accordance with your instructions. If you submit a proxy card without giving specific voting instructions, the proxies will vote those shares as recommended by the board of directors.

Q: How does the board recommend I vote on the proposals?

A: The board recommends you vote "FOR" each of the nominees to the board of directors and "FOR" the amendment to the 1996 Incentive Stock Plan.

Q: Can I revoke my proxy card?
A: Yes. You can revoke your proxy card by:

- Submitting a new proxy card;
- Giving written notice before the meeting to our Secretary stating that you are revoking your proxy card; or
- Attending the meeting and voting your shares in person.

Q: Who will count the vote?
A: The inspector(s) of election, will count the vote. A representative of our transfer agent, American Stock Transfer and Trust Company, will act as the inspector of the election.

Q: What is a "quorum?"
A: A quorum is the number of shares that must be present to hold the meeting. The quorum requirement for the meeting is one-half of the outstanding shares as of the record date, present in person or represented by proxy. If you submit a valid proxy card or attend the meeting, your shares will be counted to determine whether there is a quorum. Abstentions and broker non-votes count toward the quorum. "Broker non-votes" occur when nominees (such as banks and brokers) that hold shares on behalf of beneficial owners do not receive voting instructions from the beneficial owners by ten days before the meeting and do not have discretionary voting authority to vote those shares.

Q: Will broker non-votes or abstentions affect the voting results?
A: Although abstentions and broker non-votes count for quorum purposes, they do not count as votes "FOR" or "AGAINST" a proposal. As a result, abstentions and broker non-votes will not affect the voting results on the election of directors or the amendment to the 1996 Incentive Stock Plan.

Q: What shares are included on my proxy card?
A: Your proxy card represents all shares registered to your account in the same social security number and address.

Q: What does it mean if I get more than one proxy card?
A: Your shares are probably registered in more than one account. You should vote each proxy card you receive. We encourage you to consolidate all your accounts by registering them in the same name, social security number and address.

Q: How many votes can I cast?
A: On all matters you are entitled to one vote per share.

Q: When are shareholder proposals due for the 2001 Annual Meeting of Shareholders?
A: If you want to present a proposal from the floor at the 2001 Annual

Meeting, you must give us written notice of your proposal no later than January 16, 2001. If the date of the 2001 Annual Meeting is more than 30 calendar days before or after the date of our 2000 Annual Meeting, your written notice will be timely if we receive it by the close of business on the tenth day following the date that we publicly announce the date of the 2001 Annual Meeting. Your notice should be sent to the Secretary, Midcoast Energy Resources, Inc., 1100 Louisiana, Suite 2950, Houston, Texas 77002.

If instead of presenting your proposal at the meeting you want your proposal to be considered for inclusion in next year's proxy statement, you must submit the proposal in writing to the Secretary so that it is received at the above address by December 15, 2000.

Q: Where can I find the voting results of the meeting?

A: The preliminary voting results will be announced at the meeting. The final results will be published in our quarterly report on Form 10-Q for the second quarter of fiscal 2000.

TABLE OF CONTENTS

	PAGE
ELECTION OF DIRECTORS	5
Nominees	5
Director Compensation and Board Committees	6
Agreements Regarding the Election of Directors	7
Vote Required for Election	7
APPROVAL OF THE 1996 INCENTIVE STOCK PLAN AMENDMENT	7
Vote Required for Approval	8
OTHER INFORMATION	8
Principal Shareholders	8
Executive Officers	10
Executive Compensation	10
Executive Employment Agreements	12
Compensation Committee Interlocks and Insider Participation	13
Compensation Committee Report	13
Performance Graph	14
Certain Relationships and Related Transactions	15
OTHER MATTERS	16
Auditors	16
Section 16(a) Beneficial Ownership Reporting Compliance	16
Shareholder Proposal Information	16
Miscellaneous Matters	17
EXHIBIT A	18

A Copy of the Annual Report to Shareholders of Midcoast Energy Resources, including financial statements, is being mailed with this proxy statement. You may receive an additional copy of the Annual Report at no charge upon request directed to: Duane S. Herbst, Secretary, Midcoast Energy Resources, Inc., 1100 Louisiana, Suite 2950, Houston, Texas 77002.

ELECTION OF DIRECTORS

At the annual meeting, six directors will be elected. Each director is to hold office until the next annual meeting or until a successor is elected and qualified. The persons named below have been nominated by the board of directors. If any nominee should become unavailable for election, your proxy may be voted for a substitute nominee by the persons named in the proxy or the size of the board may be reduced accordingly; however, the board is not aware of any circumstances likely to make any nominee unavailable for election.

NOMINEES

NAME	AGE	POSITION	DIRECTOR SINCE
Dan C. Tutcher.....	51	Chairman of the Board, President, and Chief Executive Officer	1992
I. J. Berthelot, II.....	40	Executive Vice President, Chief Operating Officer and Director	1996
Ted Collins, Jr. (1).....	61	Director	1997
Curtis J. Dufour, III.....	50	Director	1999
Richard N. Richards (1)(2)....	53	Director	1996
Bruce Withers (1)(2).....	73	Director	1997

(1) Member, Compensation Committee of the board of directors.
(2) Member, Audit Committee of the board of directors.

For certain information regarding the beneficial ownership of our stock by each of the Nominees, see "Other Information - Principal Shareholders."

DAN C. TUTCHER has been Chairman of the Board, President and Chief Executive Officer since our formation in 1992 and served as Treasurer from 1995 to 1996. Since 1989, Mr. Tutcher has also been President and Chief Executive Officer of Magic Gas Corp., a Texas corporation controlled by Mr. Tutcher. Prior to its merger into the Company in 1992, Mr. Tutcher served as a Director of Nugget Oil Corporation, from 1990 to 1992. He also serves on the board of the Interstate Natural Gas Association of America and the Gas Processors Association. Mr. Tutcher holds a Bachelor of Business Administration degree from Washburn University.

I .J. (CHIP) BERTHELOT, II has been a Director since 1996 and serves as Executive Vice President and Chief Operating Officer. Mr. Berthelot has been with us since our formation in 1992. Mr. Berthelot joined Midcoast as Chief Engineer and became Vice President of Operations in 1995, Chief Operating Officer in 1996 and Executive Vice President in 1997. From 1991 to 1992 he was a gas contracts representative with Mitchell Energy and Development Co. He is a Professional Engineer, licensed in Texas and holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering from Texas A&I University.

TED COLLINS, JR. has been a Director since 1997. Mr. Collins has served as President since 1988 for Collins & Ware, Inc., a private corporation active in oil and gas exploration, production and property acquisition. He served as President of Enron Oil & Gas Company from 1986 to 1988 and prior to that held positions as President with HNG/Internorth Exploration Company and HNG Oil Company as well as Executive Vice President of American Quasar Petroleum Company. Mr. Collins also serves on the boards of Hanover Compressor Company, Queen Sand Resources, Inc. and Chaparral Resources, Inc. He graduated from the University of Oklahoma with a Bachelor of Science degree in Geological Engineering.

CURTIS J. DUFOUR, III has been a Director since March 1999 and serves as Chief Executive Officer of Dufour Petroleum, Inc., a wholly-owned subsidiary of our company. Prior to its merger with and into our company in 1999, Mr. Dufour served as President of DPI from 1988 until 1997 and as Chief Executive Officer since 1996. DPI is a private corporation engaged in the natural gas liquids ("NGL") marketing and transportation business. Prior to forming DPI, Mr. Dufour served as President of Choctaw Fuels, Inc., a company engaged in the marketing and transportation of NGLs from 1978 until 1986. He graduated from the University of Southern Mississippi with a Bachelor of Science degree in Marketing.

RICHARD (DICK) N. RICHARDS has been a Director since 1996. Mr. Richards is currently Director of New Reusable Systems for The Boeing Company. Prior to 1998, he had been with NASA where he served in several capacities since 1980. Mr. Richards was an astronaut with NASA until 1995 and flew one mission as pilot and commanded three other space shuttle missions. He also served as Manager of Space Shuttle Program Integration and Mission Director of the third Hubble Space Telescope Space Shuttle servicing mission. He holds a Bachelor of Science degree in Chemical Engineering from the University of Missouri and a Master of Science in Aeronautical Systems from the University of West Florida.

BRUCE WITHERS has served as director since 1997. From 1991 to 1996, Mr. Withers served as Chairman and Chief Executive Officer of Trident NGL, Inc. and Vice Chairman of Dynegy, Inc., formerly NGC Corporation. Dynegy is an aggregator, processor, transporter and marketer of energy products and services. Prior to joining Dynegy, Mr. Withers served as President of the Transmission and Processing Division of Mitchell Energy for 17 years. Mitchell Energy is engaged through its subsidiaries in the exploration for and production of oil and gas, natural gas processing and gas gathering and transmission. He has also served as President and Chief Operating Officer of Liquid Energy Corp. and Southwestern Gas Pipeline, two affiliates of Mitchell Energy. Mr. Withers holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering from Texas A & I University.

DIRECTOR COMPENSATION AND BOARD COMMITTEES

During the year ended December 31, 1999, the board met 10 times. Each director attended more than 75% of the board and committee meetings on which he served. Each non-employee director is currently paid a cash fee of $1,000 at the end of each calendar quarter of service, $1,000 for each regular and special meeting attended and $300 for each committee meeting attended, plus any travel expenses. Under the 1997 Non-Employee Director Stock Option Plan, these cash fees may be converted into shares of stock at the market price on the last day of the quarter in which the fees are paid. Employee directors do not receive additional compensation for service on the board or its committees. Employee directors are eligible to participate in the 1996 Incentive Stock Plan. See "Other Information--Compensation Committee Report."

The Non-Employee Director Plan entitles each newly-elected Director who is neither (i) an employee, nor (ii) a director as a result of an acquisition or financing transactions to receive options to purchase up to 15,000 shares of Common Stock on his initial election. Further, such directors are also entitled to receive an option to purchase 5,000 shares on each date they are reelected. Mr. Richards and Mr. Withers were each issued options to purchase 6,250 shares

and 5,000 shares upon their re-election in 1998 and 1999 respectively. The 1998 grants have been adjusted for the five-for-four stock split paid on March 1, 1999 to shareholders of record on February 11, 1999.

AUDIT COMMITTEE. The current members of the Audit Committee are Richard N. Richards and Bruce Withers. The Audit Committee met two times during 1999. The Audit Committee is responsible for recommending to the entire board of directors engagement and discharge of independent auditors of our financial statements, reviews the professional service provided by the independent auditors, reviews the independence of independent auditors, reviews with the auditors the plan and results of the auditing engagement, considers the range of audit and non-audit fees and reviews the adequacy of our system of internal audit controls. In addition, the Audit Committee directs and supervises special investigations as deemed necessary by the Audit Committee.

COMPENSATION COMMITTEE. The current members of the Compensation Committee are Ted Collins, Jr., Richard N. Richards and Bruce Withers. The Compensation Committee met two times during 1999. The Compensation Committee administers the 1996 Incentive Stock Plan. In this capacity, the Compensation Committee recommends all option grants or awards to our officers, executives, employees and consultants. The Compensation Committee also recommends the establishment of policies dealing with various compensation, including compensation of executive officers, and any 401(k), pension and profit sharing plans which may be created.

AGREEMENTS REGARDING THE ELECTION OF DIRECTORS

In connection with our acquisition of Republic Gas Partners, L.L.C., we were required to take steps to elect Mr. Collins and another individual to the Board for a period of two years. Effective October 1999, this agreement expired.

In connection with the Company's acquisition of Dufour Petroleum, Inc. and Flare, L.L.C., we were required to take steps to elect Mr. Dufour to the Board for a period of two years. However, in the event that Mr. Dufour's stock ownership in Midcoast falls below certain thresholds, we may request Mr. Dufour's resignation as Director. In March 1999, Mr. Dufour was elected to the Board. See "Certain Relationships and Related Transactions"

VOTE REQUIRED FOR ELECTION

Provided that a quorum is present at the Annual Meeting, the six Nominees who receive the greatest number of votes cast for election by the shareholders will be elected Directors.

THE BOARD RECOMMENDS A VOTE FOR THE ELECTION OF ALL SIX NOMINEES TO OUR BOARD OF DIRECTORS.

APPROVAL OF THE 1996 INCENTIVE STOCK PLAN AMENDMENT

On May 8, 1997, our shareholders approved the adoption of the 1996 Incentive Stock Plan. On February 24, 2000, the Compensation Committee adopted an amendment to the Incentive Plan authorizing an increase in the number of shares available for issuance from 531,250 shares to 1,000,000 shares. This increase was expressly made subject to the approval of our shareholders.

Currently, the Incentive Plan provides that a maximum of 531,250 shares may

be issued under the plan. As of the Record Date, only 12,386 shares were available for issuance upon the exercise of options granted under the plan. Thus, additional shares must be authorized for us to be able to continue to grant Incentive Awards under the plan. Furthermore, through our acquisition strategy, we have added a significant number of employees who are eligible to

receive options under the Incentive Plan; therefore, we believe a substantial increase in the number of shares authorized to be issued under the plan is warranted at this time.

The purpose of the plan is to (i) align the personal financial incentive of our employees and consultants with our long-term growth and the interests of our shareholders through the ownership and performance of our stock, and (ii) enhance our ability to attract and retain qualified employees and consultants who share primary responsibility for our management and growth. The Compensation Committee believes that the Incentive Plan has fulfilled these purposes and that the continued availability of equity incentives under the Incentive Plan will be a significant factor in our ability to attract and retain key management personnel who share primary responsibility for our management and growth. The number of participants, including officers, (whether or not Directors) currently eligible to participate in the Incentive Plan is approximately 225 employees. Persons who are not in an employment or consulting relationship with us, including non-employee Directors, are not eligible to participate in the Incentive Plan.

The Incentive Plan provides that certain amendments may only be made with the approval of our shareholders. One amendment that requires shareholder approval is an amendment that increases the maximum number of shares of stock that may be issued under the Incentive Plan. This summary of the Incentive Plan Amendment is qualified in its entirety by reference to the full text of the amendment, a copy of which is attached hereto as EXHIBIT A.

The Board believes that the continued availability of Incentive Awards under the Incentive Plan is important to our ability to attract and retain qualified management personnel and Consultants. Therefore, the Board strongly believes that the adoption of the Incentive Plan Amendment is in the best interest of our shareholders.

VOTE REQUIRED FOR APPROVAL

The affirmative vote of the holders of a majority of our shares outstanding on the Record Date, entitled to vote and represented at the Annual Meeting, in person or by proxy, is required to approve this amendment.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE FOR APPROVAL OF THE INCENTIVE PLAN AMENDMENT.

OTHER INFORMATION

PRINCIPAL SHAREHOLDERS

The following table presents certain information based on our records and filings with the SEC as of March 31, 2000, as to:

- each shareholder known by us to be the beneficial owner of more than five percent of our outstanding shares of common stock,
- each executive officer and each of the nominated directors, and
- all directors and executive officers as a group.

NAME AND ADDRESS OF BENEFICIAL OWNER (1)	AMOUNT AND NATURE OF BENEFICIAL OWNERSHIP (2)	PERCENTAGE OF OUTSTANDING OWNED
Capital Guardian Trust Company (3)..... 11100 Santa Monica Blvd. Los Angeles, CA 90025	1,822,750	14.6
State of Wisconsin Investment Board (4)..... 121 East Wilson St. Madison, WI 53702	851,337	6.8
Fidelity Management & Research Company (5)..... 82 Devonshire Street Boston, MA 02109	682,525	5.5
Dan C. Tutcher (6)(7)(8).....	872,022	7.0
Ted Collins, Jr. (9).....	541,097	4.3
Curtis J. Dufour, III (10).....	163,719	1.3
I. J. Berthelot, II (6)(7).....	69,747	*
Richard A. Robert (6)(7).....	55,308	*
Bill Bray (6)(7).....	35,693	*
Duane S. Herbst (6)(7).....	31,911	*
Bruce Withers (11).....	31,875	*
Richard N. Richards (11)(12).....	21,652	*
All Nominees and Executive (6)(7)(11)..... Officers as a group (9 persons)	1,823,024	14.3

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* Denotes less than 1%.

(1) Unless otherwise noted, the address for all persons is 1100 Louisiana, Suite 2950, Houston, Texas 77002.

(2) Except as otherwise noted, shares beneficially owned by each person as of the record date were owned of record and each person had sole voting and investment power with respect to all shares beneficially held.

(3) On February 10, 2000, Capital Guardian Trust Company filed a Schedule 13G, denoting beneficial ownership of the shares shown above as of December 31, 1999.

(4) According to information provided to us by the State of Wisconsin Investment Board, as of March 24, 2000, they reported beneficial ownership of the shares shown above.

(5) According to information provided to us by Fidelity Management & Research Company, as of March 1, 2000, they reported beneficial ownership of the shares shown above.

(6) The ownership shown in the table includes shares which may be acquired within 60 days on the exercise of options granted under the Incentive Plan by each of the persons and group, as follows: Mr. Tutcher - 24,750 shares; Mr. Berthelot - 24,750 shares; Mr. Robert - 18,150 shares; Mr. Bray - 11,562; Mr. Herbst - 14,437 shares and the group -93,649.

(7) The ownership shown in the table includes shares held through our 401(k)

Plan by each of the persons and group, as follows: Mr. Tutcher - 5,406 shares; Mr. Berthelot - 3,807 shares; Mr. Robert - 4,340 shares; Mr. Bray - 1,861; Mr. Herbst - 1,988 shares and the group - 17,402; and includes shares held through our Employee Stock Purchase Plan by each of the persons and group, as follows: Mr. Berthelot - 194 shares; Mr. Robert - 1,298 shares; Mr. Herbst -153 shares and the group - 1,645 shares.

(8) Includes 840,455 shares of Common Stock held of record by Magic Gas Corporation, an affiliate of Mr. Tutcher, 137 shares owned by Mr. Tutcher's daughter and 1,274 shares held as custodian for minor children.

(9) Includes 401,601 shares of Common Stock and 139,496 shares of Common Stock which may be acquired within 60 days on the exercise of warrants, both issued in connection with an acquisition to Cortez Natural Gas, Inc., an affiliate of Mr. Collins.

(10) All shares were beneficially owned by Mr. Dufour and his wife and such shares were acquired in connection with the Dufour/Flare Merger. See "Certain Relationships and Related Transactions."

(11) The ownership shown in the table includes shares which may be acquired within 60 days on the exercise of options granted under the Director Plan by each of the persons and group as follows: Mr. Withers - 31,875 shares; Mr. Richards - 18,125 shares and the group - 50,000 shares.

(12) All shares were beneficially owned by Mr. Richards and his wife.

EXECUTIVE OFFICERS

We currently have five executive officers: Dan C. Tutcher, President and Chief Executive Officer; I. J. Berthelot, II, Executive Vice President and Chief Operating Officer; Richard A. Robert, Chief Financial Officer and Treasurer; Bill Bray, Vice President of Business Development; and Duane S. Herbst, Vice President of Corporate Affairs and Secretary (the "Executive Officers"). See "Election of Directors-Information Regarding the Nominees" for biographical information concerning Messrs. Tutcher and Berthelot.

RICHARD A. ROBERT (34) is Chief Financial Officer and Treasurer and has been with us since our formation in 1992. Mr. Robert joined us as Controller and became Chief Financial Officer and Treasurer in 1996. From 1988 to 1992 he was an audit associate in the energy audit division of Arthur Andersen and Co. Mr. Robert is a certified public accountant and is a member of the Texas Society of Certified Public Accountants. He holds a Bachelor of Business Administration degree in Accounting from Southwest Texas State University.

BILL BRAY (51) is Vice President of Business Development and has been with us since 1990. Mr. Bray joined us as Director of Business Development and became Vice President of Business Development in 1999. He holds a bachelor's degree in business administration from Fort Hays State University.

DUANE S. HERBST (36) has been Secretary since our formation in 1992 and Vice President of Corporate Affairs since 1996. From April 1992 until its merger with us in September 1992 he held the office of President of Nugget. Since 1989 he has been Vice President of Rainbow Investments Company, a privately held corporation. He holds a Master of Business Administration degree from the University of Texas and a Bachelor of Science degree in Finance from Trinity University.

EXECUTIVE COMPENSATION

SUMMARY COMPENSATION TABLE. The following table reflects all forms of compensation for services for the years ended December 31, 1999, 1998 and 1997 for our Chief Executive Officer, Chief Operating Officer, Chief Financial Officer and Vice President of Business Development (collectively the "Named Executive Officers"). During this time no other executive officer received compensation, including bonuses which exceeded $100,000.

NAME AND PRINCIPAL POSITION	YEAR	ANNUAL COMPENSATION			LONG-TERM COMPENSATION AWARDS		ALL OTHER COMPENSATION(3)
		SALARY	BONUS	OTHER ANNUAL COMPENSATION	RESTRICTED STOCK AWARDS(1)	SECURITIES UNDERLYING OPTIONS/SARs(2)	
Dan C. Tutcher	1999	$162,500	$37,667	---	---	---	$11,471
Chief Executive	1998	$150,000	$30,000	---	---	--	$10,694
Officer	1997	$ 95,000	$ 5,000	---	---	41,250	$11,662
I. J. Berthelot, II	1999	$155,833	$29,177	---	---	12,000	$12,094
Executive Vice	1998	$135,000	$30,000	$22,168	$37,026	---	$11,961
President and COO	1997	$ 86,246	$ 7,500	$36,235	$49,840	41,250	$ 4,190
Richard A. Robert	1999	$137,500	$36,884	---	---	8,000	$12,431
Chief Financial	1998	$125,000	$30,000	$22,168	$37,026	---	$11,963
Officer	1997	$ 77,162	$12,500	$16,896	$49,840	30,250	$ 8,809
Bill Bray	1999	$106,250	$ 3,131	---	---	---	$ 8,663
Vice President -	1998	$ 86,333	$11,167	$11,675	$22,216	6,250	$ 5,198
Business Dev.	1997	$ 64,727	$ 2,500	$10,799	$29,904	17,188	$ 4,134

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(1) Includes amounts paid as reimbursement for taxes incurred on appreciation of shares of stock issued as consideration for executing employment agreements. See "Executive Employment Agreements."

(2) All numbers in this column reflect the 10% stock dividend paid on March 2, 1998 to shareholders of record on February 13, 1998 and the five-for-four stock split in March 1999.

(3) Represents our matching contributions to the Midcoast Energy Resources, Inc. Profit Sharing Plan and Trust (401(k) Plan) and certain personal benefits, including car allowances.

EMPLOYEE OPTIONS. Under the Incentive Plan, options to purchase shares of stock may be granted to executive officers and other employees. As of December 31, 1999, 464,689 shares were reserved for outstanding options and 63,511 shares were reserved and remained available for future option grants pursuant to the Incentive Plan.

OPTION GRANTS TABLE. The following table provides information concerning stock options granted to the Named Executive Officers during the year ended December 31, 1999.

INDIVIDUAL GRANTS	POTENTIAL REALIZABLE VALUE AT ASSUMED ANNUAL RATES OF STOCK PRICE APPRECIATION FOR OPTION TERM (1)

NAME	NUMBER OF SECURITIES UNDERLYING OPTIONS/SARs GRANTED(2)	PERCENT OF TOTAL OPTIONS/ SARs GRANTED TO EMPLOYEES IN FISCAL YEAR	EXERCISE PRICE PER SHARE	EXPIRATION DATE	5% ($)	10% ($)
I. J. Berthelot, II (3).....	12,000	18.6%	$16.5625	8/05/09	$124,993	$316,756
Richard A. Robert (3).....	8,000	12.4%	$16.5625	8/05/09	$ 83,329	$211,171

(1) Under the terms of the Incentive Plan, the Compensation Committee retains discretion, subject to plan limits, to modify the terms of outstanding options and to reprice the options. Because the exercise price of all options is at or above the market price per share of Common Stock at the date of grant, the potential realizable value of the options assuming no stock price appreciation is zero.

(2) Each option granted under the Incentive Plan becomes immediately exercisable on the occurrence of a Change in Control (as defined in the Incentive Plan). No stock appreciation rights were granted during 1999.

(3) These options vest 20% per year.

OPTION EXERCISES AND YEAR-END OPTION VALUES. The following table sets forth information with respect to options exercised by the Named Executive Officers during 1999, and with respect to unexercised options which have been granted to the Named Executive Officers and held by them at December 31, 1999. No stock appreciation rights are held by any Named Executive Officers.

NAME	OPTIONS EXERCISED DURING 1999		NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS/SARs AT FISCAL YEAR END (1)		VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS/SARs AT FISCAL YEAR END (2)	
	SHARES ACQUIRED #	VALUE REALIZED $	EXERCISABLE	UNEXERCISABLE	EXERCISABLE	UNEXERCISABLE
Dan C. Tutcher.....	--	--	16,500	24,750	$137,775	$206,663
I. J. Berthelot, II.....	--	--	16,500	36,750	$150,381	$227,822
Richard A. Robert.....	--	--	12,100	26,150	$110,279	$166,919
Bill Bray.....	--	--	8,125	15,313	$ 63,503	$ 97,366

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(1) In February 2000, the following additional options of each Named Executive Officer's options vested and became exercisable: Mr. Tutcher - 8,250; Mr. Berthelot - 8,250; Mr. Robert - 6,050; Mr. Bray - 3,348.

(2) Calculated by multiplying the number of shares underlying outstanding in-the-money options by the difference between the last sales price of our stock on December 31, 1999 ($16.75 per share) and the exercise price, which ranges between $7.636 and $16.80 per share. Options are in-the-money if the fair market value of the underlying stock exceeds the exercising price of the option.

EXECUTIVE EMPLOYMENT AGREEMENTS

The Named Executive Officers have entered into employment contracts, as amended, which provide for employment terms of varying lengths, the longest of which expires in April 2001 and which contain certain minimum annual base salaries, with actual salaries determined by the Compensation Committee. Two of the Named Executive Officers, Messrs. Berthelot and Robert, were awarded 79,737 and 12,267 shares of stock, respectively, as consideration for their entry into such agreements. These agreements may be terminated by mutual consent, at our

option for cause, or by death or disability. In the event termination is due to death, disability or certain changes in our ownership, the full amount of compensation remaining to be paid during the term of the agreement will be paid to the employee or his estate, after discounting at 12% to reflect the current value of unpaid amounts. See "--Compensation Committee Report."

In August 1997, we entered into Executive Severance Agreements with our executive officers, excluding Mr. Bray, under which they are entitled to certain severance benefits in the event of a change in control of Midcoast,

and in conjunction with a termination of the officer. These severance benefits include payment of an amount equal to three times the officer's annual base salary and bonus and the continuation for 36 months of any life and healthcare related benefits under which the officer and/or the officer's family is covered as of the effective date of the change in control. The terms are of these severance agreements are 18 months, but they are automatically extended an additional year unless the Board delivers written notice of termination three months prior to the end of the term.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

No member of the Compensation Committee has ever served as one of our executive officers. We issued options to Messrs. Richards and Withers upon their reelection and appointment to the board, respectively. See "Director Compensation and Board Committees." We also issued securities to Cortez Natural Gas, Inc. which is controlled by Mr. Collins, and granted certain registration rights regarding such shares, in connection with the acquisition of Republic Gas Partners, L.L.C. Cortez received the following consideration as part of this acquisition: $2,678,629 in cash, 401,601 shares of stock and warrants for 139,496 shares of stock. In addition, we agreed to grant Cortez and the other Republic owners certain demand and piggyback registration rights regarding the shares and warrants issued them.

COMPENSATION COMMITTEE REPORT

The compensation committee of the board has furnished the following report on executive compensation for fiscal 1999:

Under the supervision of the board, we seek to relate a significant portion of potential total executive compensation to our financial performance. In general, executive financial rewards may be segregated into the following significant components: base compensation, bonus and stock-based benefits.

We intend the base compensation for our executive officers to afford a reasonable degree of financial security and flexibility to those individuals who were regarded by the Compensation Committee as having acceptably discharged the levels and types of responsibilities implicit in the various executive positions. Each named executive officer has executed an employment contract with the Company. Base compensation for 1999, as adjusted, if applicable, for mid-year escalations, for each named executive officer was as follows: Mr. Tutcher $165,000, Mr. Berthelot $160,000, Mr. Robert $140,000 and Mr. Bray $106,250. In the case of Mr. Herbst, base compensation of $65,000 for fiscal 1999 was set by the Committee. Base pay reflected in the employment contracts held by those certain executive officers was set based on arms-length negotiations of each officer's employment contract. In negotiating the base pay for the executive officers, consideration was given to the compensation plans of executives in other pipeline companies. The committee believes such base pay is reasonable in light of the average compensation for executive officers of our competitors. In addition, the committee considered the salary history, past performance, credentials, age and experience of each executive officer, as well as his perceived future utility to us.

Annual bonuses are intended to reflect a policy of requiring a minimum level of financial performance before any bonuses are earned by the executive officers, with bonuses for achieving higher levels of performance directly tied to the level achieved. The following bonuses were awarded and paid in 1999 to executive officers for their performance in 1999: Mr. Tutcher $37,667; Mr. Berthelot $29,177; Mr. Robert $36,884, Mr. Bray $3,131; and Mr. Herbst

$13,702.

The board is of the view that the periodic grant of stock options to the executive officers is calculated to align the executive's economic interests with those of shareholders and to provide a direct and continuing focus upon the goal of increasing shareholder value. We granted options covering an aggregate of 25,000 shares of stock to executive officers during 1999 at 100% of the market price on the date of grant. These options were issued as follows: Mr. Berthelot - 12,000; Mr. Robert - 8,000; Mr. Herbst - 5,000. The options vest over a five-year period with a ten-year term. The Compensation Committee presently anticipates that such grants in the future will be considered only as appropriate.

The committee intends, with any necessary concurrence of the Board, to continue to consider alternate forms of stock or other incentive-based compensation with a view to affording the maximum possible long-term performance-based benefits to senior executives, at the least possible cost, and with the greatest attainable economic efficiency to Midcoast. Such benefits will be designed, as nearly as practicable, to align directly the economic interest of our executive officers with those of our shareholders.

COMPOSITION OF THE COMMITTEE. No committee member is a member of management. Collectively, the committee members owned, controlled or represented an aggregate of 594,624 shares (including shares that may be acquired pursuant to outstanding stock options or warrants within 60 days), or approximately 4.8% of the Common Stock outstanding and, accordingly, also maintain a substantial interest in the Company's performance.

The Compensation Committee

Ted Collins, Jr., Richard N. Richards and Bruce Withers

PERFORMANCE GRAPH

The following performance graph, prepared by Standard & Poor's Compustat Group, compares our stock's performance to the S&P SmallCap 600 Index and to an index of peer companies. The graph covers the period from August 9, 1996 (the date on which the our stock was registered under Section 12(g) of the Securities Exchange Act of 1934) to December 31, 1999. The graph assumes that the value of the investment in our stock and each index was $100 at August 9, 1996 and that all dividends were reinvested. The Peer Group is weighted by market capitalization. Past financial performance should not be considered to be a reliable indicator of future performance, and investors should not use historical trends to anticipate results or trends in future periods.

[graph appears here]

	AUGUST 9, 1996	YEAR ENDED DECEMBER 31, 1996	1997	1998	1999
Midcoast Energy Resources, Inc.[Legend]	$100	$ 95.07	$201.39	$221.66	$221.83
S&P SmallCap 600 Index [Legend]	$100	$112.52	$141.31	$139.46	$156.76
Peer Group [Legend] (1)	$100	$108.84	$142.94	$149.15	$147.14

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(1) Consists of Atmos Energy Corp., Cascade Natural Gas, Connecticut Energy, Energen Corp., New Jersey Resources, Northwest Natural Gas, Pennsylvania Enterprises, Piedmont Natural Gas, Public Service of North Carolina, Southwest Gas, Southwestern Energy and WICOR, Inc. Such companies comprise the Natural Gas Group of the S&P Small Cap 600 Index.

The foregoing price performance comparisons shall not be deemed incorporated by reference by any general statement incorporating by reference this Proxy Statement into any filing under the Securities Act of 1933, as amended, ("Securities Act") or under the Securities Exchange Act of 1934, as amended, except to the extent that the Company specifically incorporates this graph by reference, and shall not otherwise be deemed filed under such acts.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

In February 1999, we completed the acquisition of DPI and Flare. Mr. Dufour was the principal owner of DPI/Flare, along with several other persons. As a result of the acquisition, Mr. Dufour, received $2,985,250 in cash and 163,719 shares of stock. In addition, we agreed to elect Mr. Dufour to the Board and to grant Mr. Dufour certain piggyback registration rights as to the shares of stock he received as consideration in the merger. Under the terms of the agreement and plan of merger, all of the DPI/Flare partners received a total of $3,151,642 cash and 163,719 shares of stock. We also repaid approximately $5.5 million in DPI/Flare indebtedness and agreed to pay up to $2.5 million in cash and stock based on the future performance of DPI and Flare. The consideration we paid was based on arms length negotiations among the parties.

In addition, Mr. Dufour received compensation from us of $91,933 in 1999. This included salary of $89,423 and matching contributions to our 401(k) plan of $2,510.

In October 1997, we acquired Republic Gas Corporation by merger. In connection with this merger, Cortez Natural Gas Corp., an affiliate of Mr. Collins that owned 90% of Republic, received the following consideration: $2,678,629 in cash, 401,601 shares of stock and warrants for 139,496 shares of stock. In addition, we agreed to grant Cortez and the other Republic owners certain demand and piggyback registration rights regarding the shares and warrants issued them. The consideration we paid was based on arms length negotiations among the parties.

Stevens G. Herbst, the father of Duane S. Herbst, received total compensation from us of $117,324 in 1999. This included salary and bonus of $88,067, matching contributions to our 401(k) plan of $5,257 and payments under a non-compete agreement of $24,000. In addition, a corporation owned by Mr. Herbst received $4,554 under a net revenue interest agreement.

OTHER MATTERS

AUDITORS

On October 11, 1999, we engaged PricewaterhouseCoopers LLP as independent accountant to audit our financial statements for the year ended December 31, 1999. In connection with the hiring of PricewaterhouseCoopers LLP, on October 11, 1999, we and Hein + Associates LLP, our prior principal independent accountant, mutually agreed that Hein + Associates LLP would be replaced by PricewaterhouseCoopers LLP as our principal independent accountant. The decision to replace Hein + Associates LLP and engage PricewaterhouseCoopers LLP was approved by our board of directors. We do not anticipate that representatives of PricewaterhouseCoopers LLP will be present at the annual meeting.

Hein + Associates LLP served as our independent accountant from March 17, 1994 until we replaced them on October 11, 1999. We and Hein have not, in connection with the audit of our financial statements for each of the prior two years ended December 31, 1998 and December 31, 1997, or for any subsequent interim period prior to and including October 11, 1999, had any disagreement on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreement, if not resolved to Hein's satisfaction, would have caused Hein to make reference to the subject matter of the disagreement in connection with its reports.

The reports of Hein on our financial statements for the past two fiscal years did not contain an adverse opinion or a disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principles. We had no relationship with PricewaterhouseCoopers LLP required to be reported according to Regulation S-K item 304(a)(2) during the two fiscal years ended December 31, 1998 and December 31, 1997 or for any subsequent interim period prior to and including October 11, 1999.

SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires our executive officers and Directors and persons who own more than 10% of any registered class of our equity securities, to file reports of ownership and changes in ownership with the SEC as well as to furnish us with a copy of each such report. Additionally, SEC regulations require us to identify in our Proxy Statement any individual for whom one of the above referenced reports was not filed on a timely basis during the most recent fiscal year or prior fiscal years.

To our knowledge, based solely on review of the copies of such reports furnished to us and written representations that no other reports were required, during and with respect to the fiscal year ended December 31, 1999, all applicable Section 16 (a) filing requirements were complied with, except that Dan Tutcher was late in filing a Form 4 pertaining to the purchase of 1,000 shares of stock.

SHAREHOLDER PROPOSAL INFORMATION

If you want to present a proposal from the floor at the 2001 Annual Meeting, you must give us written notice of your proposal no later than January 16, 2001. If the date of the 2001 Annual Meeting is more than 30 calendar days before or after the date of our 2000 Annual Meeting, your written notice will be timely if we receive it by the close of business on the tenth day following the date that we publicly announce the date of the 2001 Annual Meeting. Your notice should be sent to our Secretary at 1100 Louisiana, Suite 2950, Houston, Texas

If instead of presenting your proposal at the meeting you want your proposal to be considered for inclusion in next year's proxy statement, you must submit the proposal in writing to the Secretary so that it is received at the above address by December 15, 2000.

MISCELLANEOUS MATTERS

We have included a copy of our annual report on Form 10-K, covering the fiscal year ended December 31, 1999, which has been filed with the SEC. We will bear the cost of soliciting proxies in the accompanying form, including the reimbursement of banks, brokers and other custodians, nominees, and fiduciaries for expenses in forwarding solicitation material to the beneficial owners of our stock. In addition to solicitations by mail, a number of our regular employees may, if necessary to assure the presence of a quorum, solicit proxies in person or by telephone.

By order of the board of directors,

/s/ Duane S. Herbst

Duane S. Herbst
Secretary

Houston, Texas
April 17, 2000

EXHIBIT A

AMENDMENT TO THE
1996 INCENTIVE STOCK PLAN

The 1996 Incentive Stock Plan of Midcoast Energy Resources, Inc. is hereby amended as follows, effective February 24, 2000, subject to shareholder approval:

1. The second paragraph of Section 3 is amended to read as follows in its entirety:

The Committee may grant Options, shares of Restricted Stock, Performance Awards, shares of Phantom Stock and Stock Bonuses under the Plan with respect to a number of shares of Common Stock that in the aggregate at any time does not exceed 1,000,000 shares of Common Stock, subject to adjustment pursuant to Section 12 hereof. The grant of a Cash Bonus shall not reduce the number of shares of Common Stock with respect to which Options, shares of Restricted Stock, Performance Awards, shares of Phantom Stock or Stock Bonuses may be granted pursuant to the Plan. Notwithstanding any provision in the Plan to the contrary, the maximum number of shares of Common Stock that may be subject to Incentive Awards granted to any one individual during any calendar year shall be 50,000 shares of Common Stock, subject to adjustment under Section 12 hereof. The limitation set forth in the preceding sentence shall be applied in a manner which will permit compensation generated in connection with the exercise of Options and the payment of Performance Awards to constitute "qualified performance-based compensation" for purposes of Section 162(m) of the Code, including, without limitation, counting against such maximum number of shares, to the extent required under Section 162(m) of the Code and applicable interpretive authority thereunder, any shares subject to Options that are canceled or repriced.

MIDCOAST ENERGY RESOURCES, INC.

THIS PROXY IS SOLICITED BY THE BOARD OF DIRECTORS
FOR THE ANNUAL STOCKHOLDERS' MEETING
TO BE HELD ON MAY 16, 2000

The undersigned stockholder of Midcoast Energy Resources, Inc. (the "Company") hereby appoints Dan C. Tutcher and Duane S. Herbst or either of them, attorneys and proxies of the undersigned, each with full power of substitution, to vote on behalf of the undersigned at the Annual Meeting of Stockholders to be held in the Company's Boardroom located at 1100 Louisiana, 32nd Floor, Houston, Texas at 10:00 a.m., local time, and at any adjournments of said meeting, all of the shares of common stock in the name of the undersigned or which the undersigned may be entitled to vote.

(Please sign on Reverse Side)

SEE REVERSE SIDE

* Please Detach and Mail in the Envelope Provided *

[X] Please mark your votes as in this example using dark ink only.

	For all nominees (except as indicated below)	Withhold Authority to vote all nominees listed at right	
1. Election of Directors	[ ]	[ ]	NOMINEES: Dan C. Tutcher I.J. Berthelot,II Ted Collins, Jr. Curtis J. Dufour,III Richard N. Richards Bruce Withers

Instructions: To withhold authority to vote for any individual nominee, write that nominee's name on the line provided below:

	FOR	AGAINST	ABSTAIN
2. To approve the amendment to the 1996 Incentive Stock Plan.	[ ]	[ ]	[ ]

3. In their discretion, upon such other matters as may properly come before the Annual Meeting, hereby revoking any proxy or proxies heretofore given by the undersigned.

The board of directors recommends a vote FOR the nominees and proposals above and if no contrary specification is made, the shares will be voted FOR the election of the nominees named herein and FOR the approval of Proposal 2.

The undersigned hereby acknowledges receipt of the Notice of the Annual Meeting of Stockholders, the Proxy Statement and the Company's annual report on Form 10-K furnished herewith.

PLEASE SIGN AND RETURN IN THE ENVELOPE ENCLOSED

Stockholder's Signature _____

Stockholder's Signature _____

Dated _____, 2000

Note: Signatures should agree with the name printed hereon. If stock is held in the name of more than one person. EACH joint owner should sign. Executors, administrators, trustees, guardians, and attorneys should indicate the capacity in which they sign. Attorneys should submit powers of attorney.