El Paso Natural Gas Company

1994 ANNUAL REPORT

El Paso

On the Cover

Jim Garrison, superintendent of the Waha Operating District, has worked for El Paso Natural Gas Company for 41 years. He's standing near large diameter plant piping and valves at the Waha Plant, which is located in the Permian Basin near the east end of EPG's south system. EPG receives gas from and delivers gas to a number of interstate and intrastate pipelines in the Waha area.

EL PASO

NATURAL GAS

COMPANY

To Our Shareholders:

In 1994, our earnings per share increased by 13% to $2.78 per share, excluding a litigation special charge of $12 million. Based on these continued strong financial results, the Company's Board of Directors approved a 9% increase in the common dividend to an annual rate of $1.32 per share. Since the Company's initial public offering in March 1992, our common dividend has grown at an annualized rate of almost 10%.

These financial results were a product of the hard work and dedication of our employees, who accomplished virtually all of our objectives for the year. We continued to enhance EPG's mainline throughput out of the San Juan Basin through the completion of several flexibility projects, including the installation of gas chilling on the San Juan lateral and restarting the Lincoln compressor station. Total mainline throughput increased 2% from the 1993 level. In June 1994, we filed with the Federal Energy Regulatory Commission (FERC) to enhance our San Juan mainline take-away capacity by another 300 million cubic feet per day. Completion of this project will provide our customers with even greater access to the prolific, low-cost San Juan Basin gas reserves, as well as eliminate the problem of periodic curtailments due to insufficient pipeline capacity out of the Basin.

In January 1994, we filed with the FERC for the deregulation of the Company's gathering and processing activities, and for permission to transfer those assets to a new subsidiary, El Paso Field Services Company. We expect to receive the required regulatory approvals shortly, with the transfer to be effective on January 1, 1996. Gathering throughput was up 1% in 1994, and we expect volumes to increase at a higher rate in 1995. As a part of our Field Services Company's new business, we plan to build a new natural gas liquids extraction plant at our existing Chaco Plant in northwestern New Mexico. This new cryogenic straddle plant, with an initial capacity of 400 million cubic feet per day, will be one of the largest of its kind in the United States and is expected to be operational in the first quarter of 1996, contributing significantly to future earnings.

In November 1994, we received a preliminary determination from the FERC authorizing the construction of the Mojave Northward Expansion. Although we are pleased with the Commission's approval of the project, we are not comfortable with certain aspects of its ruling. In December 1994, we filed for rehearing of the preliminary determination, asking the Commission to reconsider its ruling. Changes will be required in order for us to determine the feasiblility of proceeding with the project.

Although Mexico's economy has been deeply impacted by the recent peso devaluation, we believe significant opportunities still exist for the development of viable natural gas-fueled power projects in Mexico. For example, our Samalayuca II Power Project represents an attractive, natural gas-fired power project that Mexico both wants and needs, and in August 1994, we increased our interest in the plant from 10% to 20%. We look forward to continuing to work with our partners and the Mexican government in 1995, with the objective of initiating construction in early 1996. In addition, we believe that recently announced privatization plans in Mexico will yield significant new opportunities in the power and energy arenas.

In 1995, we will continue to pursue our principal objectives of increasing earnings contributions from non-regulated businesses while maintaining our position as the lowest-cost provider of regulated transportation services in our traditional markets and new markets off the east end of our system. We anticipate investing over $215 million in our non-regulated businesses–a 220% increase over the 1994 level. We expect these investments to position the company well for future earnings and dividend growth.

Wm A Wise

William A. Wise
Chairman of the Board, President
and Chief Executive Officer

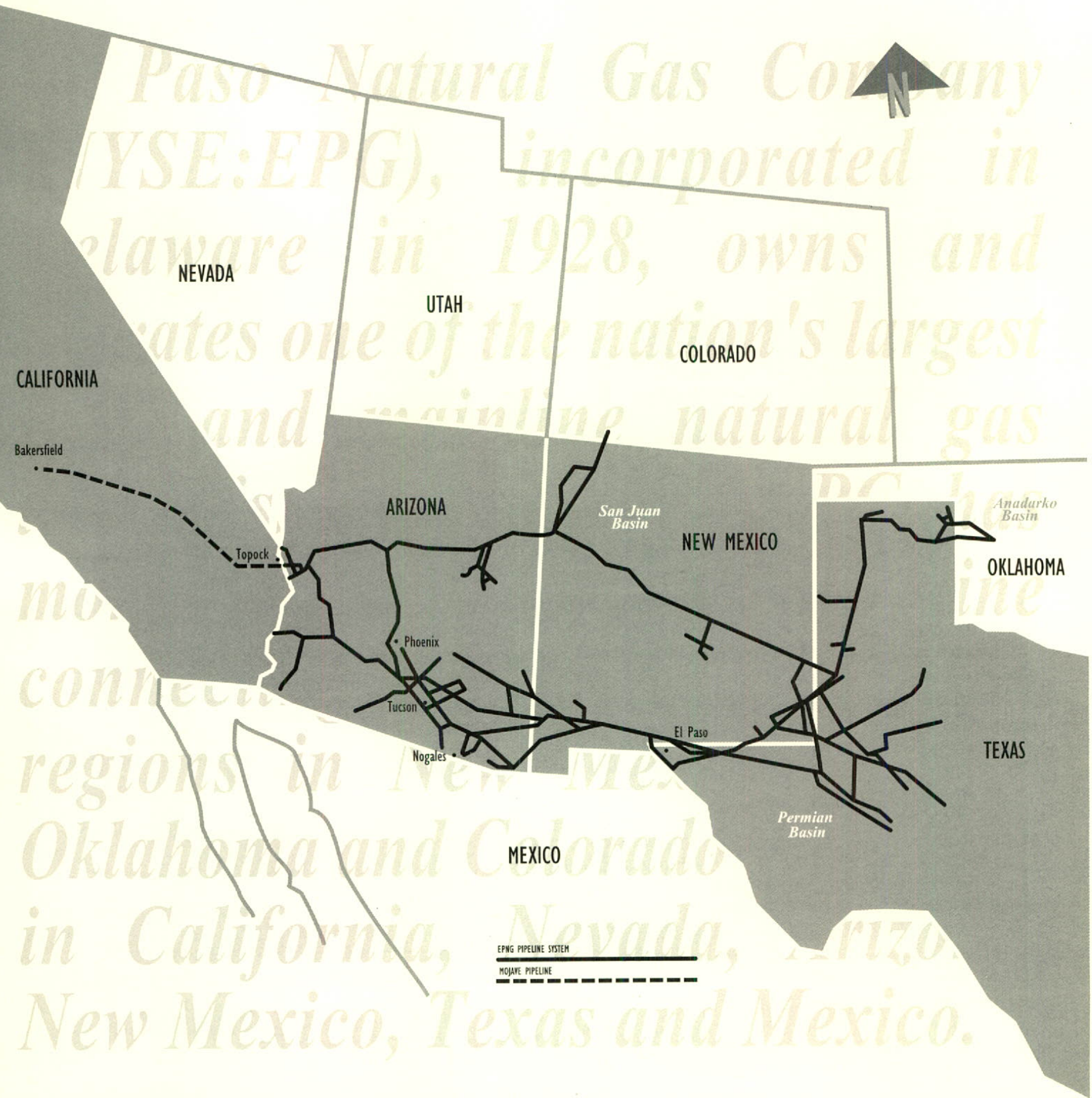
El Paso

El Paso Natural Gas Company (NYSE:EPG), incorporated in Delaware in 1928, owns and operates one of the nation's largest field and mainline natural gas transmission systems. EPG has more than 17,000 miles of pipeline connecting natural gas supply regions in New Mexico, Texas, Oklahoma and Colorado to markets in California, Nevada, Arizona, New Mexico, Texas and Mexico.

EL PASO

NATURAL GAS COMPANY

PIPELINE SYSTEM



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 [FEE REQUIRED]

For the fiscal year ended December 31, 1994

OR

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

For the transition period from to .

Commission File Number 1-2700

El Paso Natural Gas Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**74-0608280**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**
One Paul Kayser Center 100 North Stanton Street, El Paso, Texas	**79901**
(Address of Principal Executive Offices)	**(Zip Code)**

Registrant's Telephone Number, Including Area Code: (915) 541-2600

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

Common Stock, par value $3 per share

Preferred Stock Purchase Rights

6.90% Notes due 1997
9.45% Notes due 1999
7¾% Notes due 2002
8⅝% Debentures due 2012
8⅝% Debentures due 2022

The above securities are registered on the New York Stock Exchange.

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that 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 ___.

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 January 12, 1995, computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $1,066,063,169.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class: common stock, par value $3 per share. Shares outstanding on January 12, 1995: 35,387,989.

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: El Paso Natural Gas Company's definitive Proxy Statement for the 1995 Annual Meeting of Stockholders, to be filed not later than 120 days after the end of the fiscal year covered by this report, is incorporated by reference into Part III.

EL PASO NATURAL GAS COMPANY

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PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

Introduction

El Paso Natural Gas Company, incorporated in Delaware in 1928, owns and operates one of the nation's largest mainline natural gas transmission and gathering systems, connecting natural gas supply regions in New Mexico, Texas, Oklahoma, and Colorado to markets in California, Nevada, Arizona, New Mexico, Texas, and northern Mexico. As used herein, "Company" refers to El Paso Natural Gas Company and its subsidiaries, and "EPG" refers to El Paso Natural Gas Company, unless the context otherwise requires.

At December 31, 1991, EPG was a wholly owned subsidiary of Burlington Resources Inc. ("BR"). In March 1992, EPG completed an initial public offering of approximately 15 percent of its common stock in the form of newly issued shares (the "Offering"). In June 1992, BR distributed all of the EPG common shares it held to BR shareholders, the effect of which was to place all of EPG's common stock in public ownership.

El Paso Gas Marketing Company ("EPGM") was incorporated in October 1992 as a wholly owned subsidiary of EPG. EPGM commenced operations on November 1, 1992, for the purpose of conducting all of EPG's new gas marketing business, while also acting as EPG's agent in winding down its remaining role as a natural gas merchant.

El Paso Field Services Company ("EPFS") was incorporated in June 1993 as a wholly owned subsidiary of EPG. EPFS was formed for the purpose of owning, operating, acquiring, and/or constructing natural gas gathering, processing, and other related field services activities.

On June 1, 1993, the Company acquired from a wholly owned subsidiary of Enron Corp., that subsidiary's 50 percent interest in Mojave Pipeline Company ("MPC"), a general partnership. This acquisition gave the Company 100 percent ownership of MPC. MPC is a general partnership formed pursuant to the Uniform Partnership Act of the State of Texas. MPC was formed for the purpose of constructing, owning, and operating a federally regulated interstate natural gas pipeline to serve the enhanced oil recovery operations and associated cogeneration projects in the heavy oil fields in central California.

Components of Consolidated Operating Revenues

The following table sets forth the components of the Company's consolidated operating revenues:

	Year Ended December 31,		
	1994	1993	1992
		(In thousands)	
Reservation	$506,122	$483,471	$346,027
Transportation	41,102	59,631	141,789
Gas and liquid sales	225,857	280,839	237,965
Gathering and processing	66,581	51,427	41,759
All other	30,210	33,560	35,272
Total	$869,872	$908,928	$802,812

In 1994, natural gas deliveries to Southern California Gas Company ("SoCal") and Pacific Gas & Electric Company ("PG&E") accounted for 22 percent and 18 percent, respectively, of the Company's consolidated operating revenues. No other customer accounted for 10 percent or more of the Company's consolidated operating revenues.

El Paso Natural Gas Company

Operating Environment

EPG's pipeline facilities, services, and rates are regulated by the Federal Energy Regulatory Commission ("FERC") in accordance with the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of

1978 ("NGPA"). Prior to the mid-1980s, EPG was engaged primarily in the business of purchasing gas from producers at the wellhead and reselling such gas to local distribution companies. Since 1984, the natural gas transmission industry has undergone a major transformation in response to sweeping changes in market conditions and regulatory policies. These developments have resulted in: (i) the emergence of a nationwide spot market for natural gas and increasing competition in natural gas markets; (ii) a restructuring of the contractual relationships between pipelines and their traditional customers resulting in an increasing displacement of sales service by transportation service; and (iii) the renegotiation of gas purchase contracts between pipelines and producers to reduce purchase obligations, reform pricing provisions, and settle take-or-pay claims.

Beginning in April 1992, FERC issued a series of orders (the "Restructuring Rules") directing a number of significant changes to the structure of the services provided by interstate natural gas pipelines. The Restructuring Rules are intended principally to assure "comparability" (i.e., that pipeline and non-pipeline gas merchants are placed on an equal footing in competing for sales), to provide a mechanism for the allocation of pipeline capacity, and to eliminate competitive distortions arising from rate design differences between United States and Canadian pipelines. Under the Restructuring Rules' rate design, all fixed pipeline costs (including return on equity and related income taxes) are recovered through reservation charges which do not vary with actual throughput. Under the previously required rate design, return on equity and related taxes were excluded from reservation charges but were recovered along with variable costs through volumetric rates, which were rates paid for actual volumes transported on the pipeline. Generally, under the Restructuring Rules' rate design, volumetric rates are considerably lower than under the previously required rate design, and pipeline earnings are less sensitive to variations in actual throughput.

EPG is directly connected to three of the nation's most prolific gas producing areas — the San Juan, Permian, and Anadarko Basins. During 1994, EPG delivered 1.3 trillion cubic feet ("Tcf") of natural gas, accounting for approximately 6 percent of estimated total 1994 United States consumption.

EPG's system consists of approximately 17,000 miles of pipeline with 78 mainline compressor stations having an aggregate installed horsepower of approximately 1.0 million. The system's present natural gas delivery capacity to California and East-of-California markets, as discussed below, is approximately 4.6 billion cubic feet per day ("Bcf/d").

EPG's present capacity to deliver natural gas to California, the second largest natural gas market in the United States, is approximately 3.3 Bcf/d. EPG's system currently provides 48 percent of the total interstate pipeline capacity serving the State. In 1994, EPG delivered approximately 40 percent of all the natural gas consumed in California.

Demand for natural gas in the California market is projected to be less than capacity for some time to come. EPG maintains a strong competitive position in the market by virtue of the fact that its pipeline is, and is expected to remain, the lowest-cost transporter of natural gas to California and the principal means of moving gas from the San Juan Basin to the California border. EPG's pipeline capacity to California is currently fully subscribed under long-term contracts which provide for the payment of fixed reservation charges.

EPG is the principal interstate natural gas transmission system serving Arizona, including the cities of Phoenix and Tucson; southern Nevada, including Las Vegas; New Mexico; and El Paso, Texas. EPG's East-of-California market also includes deliveries to the cities of Ciudad Juárez, Cananea, and Hermosillo in northern Mexico, and the Samalayuca Power Plant outside of Ciudad Juárez. EPG's delivery capacity to these East-of-California markets is approximately 1.3 Bcf/d.

Since the late 1980s, in response to changing market demands, EPG has been delivering substantial quantities of gas from the San Juan Basin to interconnecting pipelines for ultimate redelivery to off-system markets on the Gulf Coast and in the Midwest. This alternate routing has been effectuated by exchanges ("back-hauls") between EPG and an interconnecting pipeline. Volumes of gas, which the interconnecting pipeline is otherwise scheduled to deliver to EPG for redelivery in EPG's traditional markets, are traded for like volumes of San Juan gas which EPG has accepted for delivery to the interconnecting pipeline. With EPG's 1992 completion of a system modification which made an existing pipeline segment linking the

San Juan Basin and Permian Basin bi-directional, total delivery capacity to off-system markets east of EPG's system can be as high as 1.1 Bcf/d depending on the level of demand elsewhere on EPG's system. Although their contributions to revenues and earnings are still comparatively small, off-system deliveries represent a strategic long-term diversification of EPG's market base. Presently, EPG is the largest provider of access to off-system markets for San Juan Basin producers.

Set forth below is a breakdown of EPG's natural gas deliveries by market area for the periods indicated (volumes shown are in million cubic feet per day ("MMcf/d")):

	Year Ended December 31,		
	1994	1993	1992
California	2,257	2,288	2,551
East-of-California	630	599	596
Off-system	747	691	560
Total throughput	3,634	3,578	3,707

Rate Matters

In July 1991, EPG filed for FERC approval of new system rates and placed the proposed new rates into effect on January 1, 1992, subject to refund. In July 1992, EPG again filed for new system rates to recover increased costs and return on rate base associated with EPG's expansion and modernization projects. These rates became effective on February 1, 1993, subject to refund. In the July 1992 filing, EPG's rate base increased from $752 million to approximately $1.2 billion. EPG made its compliance filing in December 1992, in accordance with the Restructuring Rules.

In January 1993, EPG, certain of its customers, and FERC staff reached a settlement agreement which led to the resolution of the above mentioned rate and restructuring proceedings. The settlement agreement was filed in January 1993 to supersede EPG's December 1992 compliance filing. As required by the FERC order, EPG filed revised rates in September 1993, which implemented the settlement agreement effective October 1, 1993.

The settlement agreement provided, in part, for the accelerated recovery of a substantial portion of EPG's investment in its underground storage facility. The amount to be recovered was approximately $56.7 million plus interest which began accruing February 1, 1993, at the FERC allowed rate, which approximates the prime rate. In March 1994, EPG received a final FERC letter order approving recovery of the $56.7 million of underground storage facility costs. Such costs are being recovered through December 31, 1996, by a demand charge mechanism.

Producer Settlement and Cost Recovery

Since 1987, EPG has incurred approximately $1.5 billion in buy-out and buy-down costs to resolve past and future take-or-pay exposure, to terminate and reform gas purchase contracts, to amend pricing and take provisions of gas purchase contracts, and to settle related litigation. EPG has filed to recover $1.1 billion of its buy-out and buy-down costs under FERC cost recovery procedures. The collection period for such costs extends through March 1996. Through December 31, 1994, EPG had recovered approximately $1.0 billion. EPG has established a reserve based on current throughput projections, for that portion of the receivables balance which is unlikely to be collected over the period through March 1996. The balance of this reserve was $9 million at December 31, 1994.

Under FERC procedures, take-or-pay cost recovery filings may be challenged by pipeline customers on prudence and certain other grounds. In October 1992, FERC approved an order, subject to rehearing, resolving all but one of the outstanding issues regarding EPG's take-or-pay proceedings. However, certain of EPG's customers have sought review of the eligibility of certain costs for which EPG has received FERC approval for recovery. The remaining issue unresolved by FERC involved the claim by several customers that EPG sought to recover an excessive amount for the value of certain production properties which were transferred to a producer as part of a 1989 take-or-pay settlement. In June 1994, FERC affirmed a 1993 decision of an Administrative Law Judge ("ALJ") which found that the valuation proposed by EPG was excessive and required EPG to refund to its customers the costs found to be ineligible for take-or-pay recovery. In July 1994, EPG filed for rehearing of the June 1994 order. In accordance with the FERC decision, EPG refunded $34 million, inclusive of interest, to its customers in September 1994. In November 1994, FERC issued an order which denied EPG's request for rehearing. EPG has filed a petition with the United States Court of Appeals for the District of Columbia Circuit ("Court of Appeals") for the review of the June 1994 order.

In January 1992, EPG completed a sale of substantially all of its remaining take-or-pay buy-out and buy-down receivables. See Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations — Financial Condition and Liquidity — Producer Settlement and Cost Recovery.

Gathering and Processing Facilities

In January 1994, EPG filed an application with FERC seeking an order which would terminate, effective January 1, 1996, certificates applicable to certain gathering and processing facilities owned by EPG on the basis that such facilities are not subject to FERC jurisdiction.

EPG intends, effective January 1, 1996, to transfer the facilities which are subject to the January 1994 application together with its nonjurisdictional gathering and processing facilities to EPFS. Such facilities are used for gathering and other nonjurisdictional functions and are an inherent part of EPG's current gathering operations. The facilities to be transferred consist of approximately 6,700 miles of various sized pipelines, compressors with an aggregate installed horsepower of 40,600, and various treating and processing plants.

Several producers and other shippers filed protests and requests for a formal hearing of the January 1994 application. The primary issues raised in the protests focus on the extent of competition in EPG's producing basins and the proper functionalization of its facilities. In response to the producer and shipper protests, EPG made a filing in March 1994 asserting that the protests raise issues already settled under EPG's settlement agreement.

In May 1994, FERC issued a series of orders which clarified its policy regarding the regulation of gathering facilities. Under the policy announced in these orders, FERC will have no authority to regulate the rates, terms, and conditions that apply to service through gathering facilities owned by an affiliate of a pipeline, except where the gatherer acts in concert with its pipeline affiliate to frustrate FERC's effective regulation over interstate transportation services. Although FERC has stated it will evaluate applications to deregulate gathering and processing facilities on a case by case basis, management believes EPG's January 1994 application will be approved.

Gas Supply

During 1994, approximately 219 wells first delivered gas into EPG's system. The total gas well availability physically connected to EPG's gathering systems was approximately 1.5 Bcf/d at year-end 1994. During 1994, EPG received an average of 2.7 Bcf/d from physical points interconnected with other pipelines or from receipt points pursuant to transportation and exchange agreements. EPG's maximum mainline system inlet capacity is 4.7 Bcf/d.

System Expansions

In April 1992, EPG completed the addition of 400 MMcf/d of mainline capacity from the San Juan Basin to the California border. This addition is committed pursuant to firm long-term contracts with fixed reservation charges. EPG also completed a system modification making an existing pipeline segment linking the San Juan Basin and Permian Basin bi-directional to allow for the eastward movement of up to 435 MMcf/d, of which 255 MMcf/d is committed pursuant to firm contracts through June 1995. The total cost of the expansion and modification projects was approximately $250 million.

In July 1992, EPG filed an application with FERC, which was amended in November 1992, to expand the delivery capacity of its system in the vicinity of Yuma, Arizona and, through an extension of its system south to San Luis Rio Colorado, Sonora, Mexico, to serve northern Mexican markets. The proposed expansion would have provided shippers the opportunity to deliver natural gas to Mexican markets in northern

Baja California via new pipeline capacity of 348 MMcf/d. In June 1994, EPG withdrew the July 1992 application, citing delays in the conversion to natural gas and expansion of the existing Benito Juárez Power Plant in Rosarito, Baja California Norte, Mexico. In withdrawing the pending application, EPG emphasized that it is not abandoning the project. At such time as the Comisión Federal de Electricidad ("CFE"), the Mexican government-owned utility, proceeds with its plans for the Benito Juárez Power Plant, EPG may refile its application.

EPG is a member of a consortium that plans to build the proposed Samalayuca II Power Plant near Ciudad Juárez, Chihuahua, Mexico. In December 1992, an award for construction was granted to the consortium by CFE. In August 1994, EPG increased its prospective ownership interest in the Samalayuca II Power Plant from 10 percent to 20 percent. CFE and the consortium signed a trust agreement in August 1994. Additional annexes to the trust agreement are currently being negotiated with CFE. The trust agreement, together with the annexes, will form the basis for seeking international financing for the Samalayuca II Power Plant project.

In March 1993, EPG filed an application with FERC to expand its system in order to provide natural gas service to the proposed Samalayuca II Power Plant and to an existing power plant in the same location. The proposed expansion would provide an additional 300 MMcf/d of capacity at a cost of approximately $57 million. In November 1993, FERC issued an order which approved the proposed border crossing facility south of Clint, Texas that would connect EPG's facilities with facilities in Mexico. FERC deferred action on the remainder of the March 1993 filing until EPG demonstrates that it has executed long-term contracts or binding precedent agreements for a substantial amount of the firm capacity of the proposed facilities. FERC required the executed contracts or agreements by January 1995. EPG has advised FERC that it does not have the contracts or agreements at this time. EPG has requested that FERC not dismiss the March 1993 application. Management believes that Mexico wants and needs this natural gas project and the process of obtaining contracts is ongoing. In December 1993, PG&E, SoCal, and the California Public Utilities Commission ("CPUC") jointly filed a motion with FERC seeking clarification or rehearing of the November 1993 FERC order on the Samalayuca II Power Plant project discussed above.

In April 1994, EPG filed an application with FERC for a certificate of public convenience and necessity to build a 98 mile pipeline to parallel and loop its existing Havasu Crossover Line. The proposed pipeline would allow for the transfer of 468 MMcf/d of San Juan Basin gas to EPG's south system and would enhance EPG's overall system flexibility to meet market demands. The project is expected to cost approximately $62 million. At the request of several of EPG's customers, FERC held a technical conference in August 1994 with respect to the April 1994 application. The application is currently pending before FERC.

In June 1994, EPG filed an application with FERC for a certificate of public convenience and necessity to expand its existing mainline system in the San Juan Basin by approximately 300 MMcf/d at a cost of about $26 million. The proposed expansion would accommodate increased volumes and provide markets with enhanced access to San Juan Basin gas supplies. FERC held a technical conference in August 1994 with respect to the June 1994 application. The application is currently pending before FERC.

Master Separation Agreement

In contemplation of the separation of EPG from all other BR-controlled entities, EPG, BR, and Meridian Oil Holding Inc. ("Meridian"), a wholly owned subsidiary of BR, engaged in a comprehensive review of business and contractual relationships necessary and appropriate for the efficient and effective business operations and long-term planning of both EPG and Meridian. These business relationships are addressed in detail in a Master Separation Agreement (the "Separation Agreement"), dated January 15, 1992, and related operative agreements provided for therein.

The Separation Agreement and related operative agreements provide for specific and detailed operating agreements, transportation service agreements, natural gas liquids marketing agreements, and gas supply arrangements between EPG and Meridian, including Meridian's affiliates, which are appropriate to facilitate stand-alone operations by the companies. The Separation Agreement also provides to Meridian certain defined preferential purchase rights, extending for a period of five years, with respect to EPG's San Juan Basin gathering system which is of significant importance to the business activities of both EPG and Meridian. In addition, the Separation Agreement specifically addresses matters relating to the allocation of pension fund assets and liabilities, tax sharing and allocation, right-of-way access and usage, and indemnification rights and obligations, among other things. The contractual and business arrangements, insofar as they relate to FERC jurisdictional service provided by EPG to Meridian, are representative of arrangements with respect to FERC jurisdictional services which EPG can offer to non-affiliated companies situated similarly to Meridian. In instances where Meridian may have a right to acquire certain assets from EPG under the Separation Agreement, including any acquisition of the San Juan Basin gathering system, Meridian would pay EPG the fair market value for such assets. The foregoing discussion is only a summary of certain provisions of the Separation Agreement and the related operative agreements provided for therein and is qualified in its entirety by reference to the Separation Agreement and such operative agreements.

Competition

Currently, EPG faces significant competition from other companies which transport natural gas to the California market. Competition generally occurs on the basis of price, quality, and reliability of service.

The total present interstate pipeline capacity for delivering natural gas to the California border is approximately 6.9 Bcf/d. In addition to EPG, three other major interstate pipelines presently deliver natural gas to California. Transwestern Pipeline Company ("Transwestern") has the capacity to deliver approximately 1.1 Bcf/d from Permian, Anadarko, and San Juan Basin supply sources. Kern River Gas Transmission ("Kern River") has the capacity to deliver approximately 700 MMcf/d from Rocky Mountain supply sources. In 1992, Kern River held an open season to determine interest in expanding capacity to California; however, they have asked FERC to postpone action on their pending certificate application which would have expanded their system capacity by 452 MMcf/d. Pacific Gas Transmission Company ("PGT") has the capacity to deliver about 1.8 Bcf/d of Canadian gas after completion of a 755 MMcf/d expansion in November 1993. This expansion consumed 500 MMcf/d of additional market that both Transwestern and EPG would have competed to serve. However, the impact of the PGT expansion to EPG in 1994 was offset by an increase in demand, which resulted from a decrease in the availability of hydroelectric power.

EPG's largest single contract for interstate capacity to California is its 1,450 MMcf/d contract with SoCal, which has a primary term ending August 31, 2006. In 1992, SoCal relinquished 300 MMcf/d pursuant to this contract (out of an original contract demand quantity of 1,750 MMcf/d), all of which was subsequently subscribed by new firm shippers under long-term contracts. Pursuant to its contract, SoCal has notified EPG of its intent to exercise its second option provided in the contract to relinquish an additional 300 MMcf/d of capacity on January 1, 1996. From and after the January 1, 1996 relinquishment, SoCal's contract demand quantity will remain at the 1,150 MMcf/d level for the balance of the term. PG&E has a contract for 1,140 MMcf/d of firm capacity rights on EPG's system. This contract has a primary term ending December 31, 1997. The amount of firm capacity rights, if any, that PG&E will maintain on EPG's system after the expiration of the current contract cannot be determined at this time. EPG will seek to offset future reductions in existing firm capacity commitments through new contracts with various natural gas users in California which are now served indirectly through SoCal and PG&E, as well as through the development of additional East-of-California and northern Mexico markets. In seeking new customers in California for such capacity, EPG expects to face significant competition from the other pipelines serving that state.

EPG also faces varying degrees of competition from the use of alternative energy sources, such as electricity, coal, and oil. However, competitive pressure from alternative energy sources is less prevalent in EPG's market area due to strict environmental regulations in California.

Mojave Pipeline Company

Operating Environment

MPC's pipeline facilities, services, and rates are regulated by FERC in accordance with the NGA and the NGPA.

In 1990, FERC issued orders authorizing MPC to construct and operate its pipeline facilities, which commenced operations in March 1992. MPC's system consists of approximately 400 miles of pipeline with one mainline compressor station. The system's present natural gas delivery capacity is 400 MMcf/d. MPC's only business is natural gas transportation.

Set forth below are MPC's natural gas deliveries for the periods indicated:

	Year Ended December 31,		
	1994	1993	1992
		(MMcf/d)	
Total MPC throughput	247	231	197

Mojave Pipeline Operating Company ("MPOC"), a wholly owned subsidiary of MPC, is a Texas corporation. MPOC serves as MPC's agent in the management of MPC's pipeline facilities and the design and construction of future MPC pipeline expansions.

Rate Matters

MPC filed a service and rate design restructuring plan in November 1992 in compliance with FERC's industry-wide Restructuring Rules. In March 1993, FERC issued an order essentially approving MPC's compliance filing, subject to changes, which were made in an amended restructuring plan in March 1993.

Several of MPC's customers filed protests and requests for rehearing of the March 1993 FERC order. The rehearing requests were denied, and FERC approved the amended restructuring plan in July 1993 with an effective date of August 1, 1993. In October 1993, FERC issued an order which denied requests for rehearing of the July 1993 order. Several of MPC's customers have filed petitions with the Court of Appeals for review of the March 1993, July 1993, and October 1993 orders. These petitions are currently pending before the Court of Appeals. The primary issues on appeal pertain to FERC's requirement that MPC's rates for firm transportation service be based upon Straight Fixed Variable ("SFV") rate design rather than Modified Fixed Variable ("MFV") rate design. The application of SFV rates requires MPC's existing firm shippers to pay a higher proportion of their total transportation rate in the reservation component of the rate. Such shippers have contended that FERC's application of SFV rate design to MPC unlawfully abrogates the rate provisions of MPC's service agreements and constitutes an unlawful rate increase. Management believes the Court of Appeals will uphold SFV rates as applied to MPC.

Gas Supply

During 1994, MPC received an average of approximately 250 MMcf/d at physical points of interconnection with other pipelines pursuant to transportation agreements. MPC's designed mainline system inlet capacity is 400 MMcf/d.

System Expansion

In March 1993, MPC filed an application, which was amended in November 1993 and April 1994, for a certificate of public convenience and necessity to build and operate a 475 MMcf/d expansion of its existing system at an estimated cost of approximately $500 million.

In December 1993, FERC held a public conference to examine the question raised by CPUC and PG&E regarding MPC's proposed expansion. The primary issue was whether FERC or CPUC should have jurisdiction over the expansion. In February 1994, FERC issued an order determining that it has exclusive jurisdiction over MPC and its proposed expansion. In March 1994, CPUC, PG&E, and other parties filed for rehearing or clarification of FERC's February 1994 order. The petitions for rehearing and/or clarification are pending action by FERC. In November 1994, FERC unanimously approved an order granting MPC a preliminary determination, subject to possible later modification, issuing the requested certificate of public convenience and necessity for the proposed expansion. FERC requested certain further information from the parties to determine whether PG&E, which is currently the principal gas supplier in the region to be served by the expansion project, is entitled to any compensation from MPC and/or EPG as a result of MPC's bypass of PG&E gas service. MPC and EPG have provided FERC with the requested information. The preliminary determination did not address the jurisdictional issues pending before FERC on rehearing of the February 1994 order. In December 1994, MPC and other parties filed requests for rehearing of the preliminary determination asking for reconsideration of rate and other modifications ordered by FERC. If FERC does not make significant changes to the preliminary determination, MPC will not go forward with the expansion. MPC expects to receive a final FERC certificate in the second quarter of 1995.

El Paso Gas Marketing Company

EPGM buys and sells natural gas under both short-term and long-term transactions, capitalizing on the strength of EPG's traditional market areas, as well as the new markets developing in the southwestern United States and northern Mexico.

As EPG's agent, EPGM is responsible for managing EPG's gas sales arrangements with West Coast and Southwestern utilities and municipalities. EPGM is also responsible for managing EPG's remaining long-term gas purchase agreements which decline to a level of 25 MMcf/d in 1995 and will continue to decline in subsequent years.

Other Matters

Environmental

EPG is subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations require EPG to remove or remedy the effect on the environment of the disposal or release of specified substances at ongoing and former operating sites. EPG currently has environmental contingencies for the cleanup of hazardous wastes found contaminating soil and ground and surface water. As of December 31, 1994, EPG had a reserve of approximately $40 million to cover these remediation activities. EPG believes the Clean Air Act Amendments of 1990 ("CAAA") will impact the Company's operations in the following areas: (i) potential required reductions in the emissions of nitrogen oxides ("NOx") in non-attainment areas; (ii) the requirement for air emissions permitting of existing facilities; and (iii) enhanced monitoring of air emissions. EPG anticipates capitalizing the equipment costs associated with complying with CAAA and estimates that approximately $30 million will be spent from 1995 through 2005. However, the United States Environmental Protection Agency's ("EPA's") proposed enhanced monitoring rules, when finalized, could potentially impose greater costs to the Company. Additionally, EPG estimates it will spend approximately $14 million through 1995 for additional remediation projects of a capital nature. Details regarding specific environmental contingencies are presented in Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations — Financial Condition and Liquidity — Environmental and in Note 4 of Notes to Consolidated Financial Statements.

Encumbrances

Substantial portions of the Company's pipeline systems are constructed and maintained pursuant to rights-of-way, easements, permits, and licenses or consents on and across properties owned by others. Compressor stations, related facilities, and a natural gas liquid extraction plant are located in whole or in part upon land owned by the Company or upon sites held under leases or under permits issued or approved by public authorities.

Employees

The Company had 2,403 and 2,460 full-time employees on December 31, 1994, and 1993, respectively.

Executive Officers of the Registrant

The executive officers of EPG as of January 12, 1995, were as follows:

Name	Office	Officer Since	Age
William A. Wise	Chairman of the Board, President, and Chief Executive Officer	1983	49
Luino Dell'Osso, Jr.	Vice Chairman of the Board and Chief Operating Officer	1990	55
Richard Owen Baish	Executive Vice President	1987	48
H. Brent Austin	Senior Vice President and Chief Financial Officer	1992	40
Michael C. Holland	Senior Vice President	1982	53
Joel Richards III	Senior Vice President	1990	48
John W. Somerhalder II	Senior Vice President	1990	39
Larry R. Tarver	Senior Vice President	1988	51
Britton White, Jr.	Senior Vice President and General Counsel	1991	51

Mr. Wise has been Chairman of the Board of EPG since January 1994. He has been Chief Executive Officer since January 1990 and President since April 1989.

Mr. Dell'Osso has been Vice Chairman of the Board of EPG since September 1994 and Chief Operating Officer since November 1990. He was Executive Vice President from November 1990 to August 1994. He was Senior Vice President and Chief Financial Officer of BR from April 1989 to October 1990.

Mr. Baish has been Executive Vice President of EPG since September 1994. He was Senior Vice President from November 1990 to August 1994. He was General Counsel and Corporate Secretary from November 1990 to December 1990 and Vice President and Associate General Counsel from March 1987 to October 1990.

Mr. Austin has been Senior Vice President and Chief Financial Officer of EPG since April 1992. He was Vice President, Planning and Treasurer of BR from November 1990 to March 1992 and Assistant Vice President, Planning of BR from January 1989 to October 1990.

Mr. Holland has been Senior Vice President of EPG since January 1991. He was a Vice President from June 1982 to December 1990. Mr. Holland has also been President and Chief Executive Officer of MPOC since October 1989.

Mr. Richards has been Senior Vice President of EPG since January 1991. He was Vice President from June 1990 to December 1990. He was Senior Vice President, Finance and Human Resources of Meridian Minerals Company, a wholly owned subsidiary of BR, from October 1988 to June 1990.

Mr. Somerhalder has been Senior Vice President of EPG since August 1992. He was Vice President from January 1990 to July 1992.

Mr. Tarver has been Senior Vice President of EPG since September 1994. He was Vice President from December 1988 to August 1994.

Mr. White has been Senior Vice President and General Counsel of EPG since March 1991. From March 1991 to April 1992, he was also Corporate Secretary of EPG. For more than five years prior to that time, Mr. White was a partner in the law firm of Holland & Hart.

ITEM 3. LEGAL PROCEEDINGS

In *El Paso Natural Gas Company and Meridian Oil Gathering Inc. v. Amoco Production Company,* filed in Delaware Chancery Court ("the Court") on May 8, 1991, Amoco Production Company ("Amoco") alleged breaches by EPG and a then affiliated company, Meridian Oil Gathering Inc. ("MOGI"), of certain gas purchase, gathering, and transportation agreements pertaining to natural gas produced by Amoco in the

San Juan Basin. Amoco alleged breach of "favored nations" contractual provisions regarding services to be performed by EPG, including those relating to transportation capacity and rates. Amoco sought a court order requiring specific performance by EPG and MOGI with respect to future transportation services and an award of monetary damages of an undetermined amount for alleged past breaches of contract. On March 4, 1992, the Court issued a Memorandum Opinion which, among other things, denied Amoco's motion for partial summary judgment and concluded that the Amoco contracts at issue do not contain the general "favored nations" rights claimed by Amoco. The Court further concluded that EPG's and MOGI's motions for summary judgment, seeking dismissal of Amoco's counterclaim against MOGI, should be granted. Conoco Inc. ("Conoco") asserted claims similar to Amoco's original claims, involving lesser quantities of gas, in a separate Delaware Chancery Court proceeding filed on December 30, 1991, *Conoco Inc. v. El Paso Natural Gas Company*. In August 1992, the *Amoco* and *Conoco* cases were consolidated, MOGI was dismissed as a party, and Amoco and Conoco filed amended pleadings to restate their claims in light of the court's March 4, 1992 ruling. EPG and Conoco concluded a settlement agreement which resulted in dismissal of the Conoco claims. Trial of the Amoco claims concluded on July 15, 1993, and post-trial briefing and oral arguments concluded in early November 1993. On March 29, 1994, the Court rendered a decision in favor of Amoco. As a result of the Court's decision, EPG will be required to refund to Amoco approximately $15 million, plus accrued interest. In connection with the *Amoco* decision, EPG recorded a litigation special charge of approximately $19 million in the first quarter of 1994. After additional briefing, the Court issued its opinion respecting certain contested damages issues on December 16, 1994. EPG intends to appeal the final order, which will be entered as soon as the parties reach agreement as to its form.

TransAmerican Natural Gas Corporation ("TransAmerican") has filed a complaint in a Texas state court against various parties, including EPG, alleging fraud, tortious interference with contractual relationships, economic duress, civil conspiracy, and violation of state antitrust laws. The complaint, as amended, seeks unspecified actual and exemplary damages. EPG is actively defending the matter and has initiated collateral proceedings challenging both the validity of TransAmerican's claims and the jurisdiction of the forum in which they were filed. No discovery has been commenced pending resolution of these threshold issues. Based on information available at this time, management believes that the claims made by TransAmerican have no factual or legal basis and that the ultimate resolution of this matter will not have a materially adverse effect on the Company's financial condition.

The United States Department of Justice ("Justice Department") terminated an investigation of EPG's natural gas meter sales and installation practices in the San Juan Basin on January 6, 1995. EPG and the Justice Department agreed to a consent decree which was filed in the United States District Court for the District of Columbia on January 12, 1995. The consent decree stipulates that EPG may not require a well operator to purchase meter facilities or meter installation equipment as a condition of access to its gathering system in the San Juan Basin, and requires EPG to inform well operators that they have the legal right to provide their own meter installation services. The consent decree further provides that any meter installation undertaken by third parties must be done in accordance with environmental and safety standards specified by EPG. Moreover, EPG has the right to inspect such installations to ensure that they conform to standards that apply uniformly on EPG's gathering system. Records of EPG's inspection activities will be maintained to document compliance with EPG's standards and procedures. Based on its participation in the Justice Department investigation, management concluded that there was no evidence that EPG's meter installation practices violated any applicable law, and no fines or monetary penalties were imposed on EPG. The consent decree, which may be entered as a binding, final judgment following a required sixty-day public comment period, requires no material change in EPG's existing business practices.

The Company is a named defendant in numerous lawsuits and a named party in numerous governmental proceedings arising in the ordinary course of business. While the outcome of such lawsuits or other proceedings against the Company cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the Company's financial condition.

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

During the fourth quarter of 1994, no matters were submitted to a vote of security holders.

PART II

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

All outstanding common stock of EPG was owned by BR until March 1992. In March 1992, EPG completed the Offering. In June 1992, BR distributed its 31.4 million shares of EPG common stock, which represented approximately 85 percent of EPG's outstanding common stock, to BR shareholders. As a result, BR no longer retains an ownership interest in EPG.

EPG's common stock is traded on the New York Stock Exchange. As of January 12, 1995, the approximate number of holders of record of common stock was 22,046. This does not include individual participants on whose behalf a clearing agency or its nominee holds EPG's common stock.

The following table reflects the high and low sales prices for, and cash dividends declared on, EPG's common stock based on the daily composite listing of stock transactions for the New York Stock Exchange.

	High	Low (Per share)	Dividends
1994			
First Quarter	$41.875	$35.250	$0.3025
Second Quarter	$39.000	$31.500	$0.3025
Third Quarter	$35.375	$31.625	$0.3025
Fourth Quarter	$34.750	$29.875	$0.3025
1993			
First Quarter	$38.000	$30.250	$0.2750
Second Quarter	$40.250	$35.250	$0.2750
Third Quarter	$40.375	$36.125	$0.2750
Fourth Quarter	$39.500	$33.750	$0.2750

In January 1995, EPG's Board of Directors ("the Board") declared a quarterly dividend of $0.33 per share on EPG's common stock, payable on April 3, 1995 to shareholders of record on March 10, 1995.

EPG has made available a Continuous Odd-Lot Stock Sales Program ("Program") in which shareholders of EPG owning beneficially fewer than 100 shares of EPG's common stock ("Odd-lot Holders") are offered a convenient method of disposing of all their shares without incurring the customary brokerage costs associated with the sale of an odd-lot. Only Odd-lot Holders are eligible to participate in the Program. The Program is strictly voluntary, and no Odd-lot Holder is obligated to sell pursuant to the Program. A brochure and related materials describing the Program were sent to Odd-lot Holders in February 1994. The Program currently does not have a termination date, but EPG may suspend the Program at any time. Inquiries regarding the Program should be directed to The First National Bank of Boston.

EPG has made available a Dividend Reinvestment and Common Stock Purchase Plan ("Plan") which provides all shareholders of record a convenient and economical means of increasing their holdings in EPG's common stock. A shareholder who owns shares of common stock in street name or broker name and who wishes to participate in the Plan will need to have his or her broker or nominee transfer the shares into the shareholder's name. The Plan is strictly voluntary, and no shareholder of record is obligated to participate in the Plan. A brochure and related materials describing the Plan were sent to shareholders of record in November 1994. The Plan currently does not have a termination date, but EPG may suspend the Plan at any time. Inquiries regarding the Plan should be directed to The First National Bank of Boston.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	1994	1993(e)	1992	1991	1990
	(In thousands, except per share amounts)				
For the Year:					
Operating revenues	$ 869,872	$ 908,928	$ 802,812	$ 735,196	$ 851,750
Depreciation and amortization	65,037	54,051	73,229	61,300	67,098
Litigation special charge(a)	15,062	—	—	—	—
Operating income	222,295	229,245	184,910	184,919	190,012
Income from continuing operations before income taxes	148,076	150,826	123,289	140,500	128,481
Income taxes	58,463	59,153	46,963	51,956	44,847
Income from continuing operations	89,613	91,673	76,326	88,544	83,634
Earnings per common share — continuing operations	2.45	2.46	2.12	2.82	2.66
Average common shares outstanding	36,632	37,212	36,049	31,422	31,422
Cash dividends declared per common share(b)	1.21	1.10	.75	—	—
At Year End:					
Total assets(c)	2,331,771	2,269,663	2,050,729	2,301,932	3,817,896
Payable to BR, including current portion	—	—	—	624,804	—
Long-term debt(d)	779,097	795,783	637,074	249,942	848,633
Stockholders' equity(c)	709,636	707,548	668,992	814,878	1,828,261

(a) Litigation special charge related to the *Amoco* decision (See Item 3 — Legal Proceedings).

(b) Represents dividends declared subsequent to the Offering.

(c) In May 1991, EPG declared and paid a dividend of $175 million to its then parent company, The El Paso Company ("TEPCO"). In September 1991, EPG declared a dividend of all its Oil and Gas Operations Segment to TEPCO. The total amount of that dividend was $925 million. In addition, EPG declared and paid dividends to BR totaling $55 million in 1991 and $274 million prior to the Offering in 1992.

(d) Excludes current maturities.

(e) MPC was consolidated for May 1993 through December 1993.

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

Financial Condition and Liquidity

Cash provided by operating activities was $253 million for 1994 compared with $236 million for 1993. The increase from the previous year was primarily due to net insurance claims received, lower net tax payments, lower insurance prepayments, higher collections of EPG's investment in its underground storage facility, and timing differences in working capital receipts and disbursements, partially offset by lower reserves for regulatory issues and take-or-pay refunds to customers.

Cash provided by operating activities was $236 million for 1993 compared with $334 million for 1992. The decrease from the previous year was primarily due to proceeds received in 1992 from the sale of the direct bill portion of the take-or-pay receivables, lower take-or-pay collections in 1993, rate refund payments resulting from the settlement agreement, and costs incurred to repair flood damaged pipelines (see *Other* of this section), partially offset by decreased tax payments in 1993.

Acquisitions

On June 1, 1993, the Company acquired from a wholly owned subsidiary of Enron Corp., that subsidiary's 50 percent interest in MPC, for approximately $40 million in cash, representing the approximate book value of the investment. The acquisition, which was funded by internally generated cash flow, gave the Company 100 percent ownership of MPC. The acquisition was accounted for using the purchase method.

In conjunction with the acquisition, the following liabilities were assumed:

	(In thousands)
Fair value of assets acquired	$145,643
Cash paid	39,396
Liabilities assumed	$106,247

The operating results of MPC are included in the Company's consolidated results of operations for 1994 and May 1993 through December 1993. The Company's previously owned 50 percent equity interest in MPC is included in other-net in the Consolidated Statement of Income.

The following pro forma summary presents the consolidated results of operations of the Company as if the acquisition had occurred as of January 1, 1993 or January 1, 1992. These pro forma results have been prepared for comparative purposes only and do not purport to be indicative of what may have resulted had the acquisition occurred as of those dates or of results which may occur in the future.

	Year Ended December 31,	
	1993	1992
	(In thousands, except per share amounts)	
Operating revenue	$922,593	$834,181
Net income	93,102	78,603
Earnings per common share	2.50	2.18

EPG is currently in negotiations to effect a merger with Hadson Corporation. The terms of the deal have not been finalized and are subject to the approval of the Board.

Rates and Regulatory Matters

In July 1991, EPG filed for FERC approval of new system rates and placed the proposed new rates into effect on January 1, 1992, subject to refund. In July 1992, EPG again filed for new system rates to recover increased costs and return on rate base associated with EPG's expansion and modernization projects. These rates became effective on February 1, 1993, subject to refund. In the July 1992 filing, EPG's rate base increased from $752 million to approximately $1.2 billion. EPG made its compliance filing in December 1992, in accordance with the Restructuring Rules.

In January 1993, EPG, certain of its customers, and FERC staff reached a settlement agreement which led to the resolution of the above mentioned rate and restructuring proceedings. The settlement agreement was filed in January 1993 to supersede EPG's December 1992 compliance filing. As required by the FERC order, EPG filed revised rates in September 1993, which implemented the settlement agreement effective October 1, 1993. Under the settlement agreement, EPG refunded a total of approximately $56 million, inclusive of interest, in the fourth quarter of 1993. EPG had provided for these rate refunds as revenues were collected.

The settlement agreement provided, in part, for the accelerated recovery of a substantial portion of EPG's investment in its underground storage facility. The amount to be recovered was approximately $56.7 million plus interest which began accruing February 1, 1993, at the FERC allowed rate, which approximates the prime rate. In March 1994, EPG received a final FERC letter order approving recovery of the $56.7 million of underground storage facility costs. Such costs are being recovered through December 31, 1996, by a demand charge mechanism. The amount recovered through December 31, 1994 was $32 million. The outstanding balances at December 31, 1994, and 1993 were $24 million and $37 million, respectively, of which $12 million is reflected in the current portion of other regulatory assets for both periods and $12 million and $25 million, respectively, are included in other regulatory assets in the Consolidated Balance Sheet. The settlement agreement also established new depreciation rates for certain of EPG's facilities effective January 1, 1992.

As specified in the settlement agreement, EPG is obligated to file a rate change to be effective not later than January 1, 1996.

In January 1994, EPG filed an application with FERC seeking an order which would terminate, effective January 1, 1996, certificates applicable to certain gathering and processing facilities owned by EPG on the basis that such facilities are not subject to FERC jurisdiction.

EPG intends, effective January 1, 1996, to transfer the facilities which are subject to the January 1994 application together with its nonjurisdictional gathering and processing facilities to EPFS. Such facilities are used for gathering and other nonjurisdictional functions and are an inherent part of EPG's current gathering operations. The facilities to be transferred consist of approximately 6,700 miles of various sized pipelines, compressors with an aggregate installed horsepower of 40,600, and various treating and processing plants.

Several producers and other shippers filed protests and requests for a formal hearing of the January 1994 application. The primary issues raised in the protests focus on the extent of competition in EPG's producing basins and the proper functionalization of its facilities. In response to the producer and shipper protests, EPG made a filing in March 1994 asserting that the protests raise issues already settled under EPG's settlement agreement.

In May 1994, FERC issued a series of orders which clarified its policy regarding the regulation of gathering facilities. Under the policy announced in these orders, FERC will have no authority to regulate the rates, terms, and conditions that apply to service through gathering facilities owned by an affiliate of a pipeline, except where the gatherer acts in concert with its pipeline affiliate to frustrate FERC's effective regulation over interstate transportation services. Although FERC has stated it will evaluate applications to deregulate gathering and processing facilities on a case by case basis, management believes EPG's January 1994 application will be approved.

MPC filed a service and rate design restructuring plan in November 1992 in compliance with FERC's industry-wide Restructuring Rules. In March 1993, FERC issued an order essentially approving MPC's compliance filing, subject to changes, which were made in an amended restructuring plan in March 1993.

Several of MPC's customers filed protests and requests for rehearing of the March 1993 FERC order. The rehearing requests were denied, and FERC approved the amended restructuring plan in July 1993 with an effective date of August 1, 1993. In October 1993, FERC issued an order which denied requests for rehearing of the July 1993 order. Several of MPC's customers have filed petitions with the Court of Appeals for review of the March 1993, July 1993, and October 1993 orders. These petitions are currently pending before the

Court of Appeals. The primary issues on appeal pertain to FERC's requirement that MPC's rates for firm transportation service be based upon SFV rate design rather than MFV rate design. The application of SFV rates requires MPC's existing firm shippers to pay a higher proportion of their total transportation rate in the reservation component of the rate. Such shippers have contended that FERC's application of SFV rate design to MPC unlawfully abrogates the rate provisions of MPC's service agreements and constitutes an unlawful rate increase. Management believes the Court of Appeals will uphold SFV rates as applied to MPC.

MPC is required to file a rate change three years after its in-service date of March 1, 1992. MPC expects to make a filing early in 1995.

Producer Settlement and Cost Recovery

Since 1987, EPG has made, or has committed to make, buy-out and buy-down payments totaling \$1.5 billion to resolve past and future take-or-pay exposure, to terminate and reform gas purchase contracts, to amend pricing and take provisions of gas purchase contracts, and to settle related litigation. These payments resolved virtually all the outstanding producer claims asserted against EPG and terminated or prospectively reformed substantially all of EPG's remaining gas purchase contracts, with the result that EPG no longer has any material take-or-pay exposure. In certain cases, EPG resolved claims by making recoupable prepayments. At December 31, 1994, and 1993, the recoupable prepayment balances were \$6 million and \$9 million, respectively.

EPG has filed to recover \$1.1 billion of its buy-out and buy-down costs under FERC cost recovery procedures. The collection period for such costs extends through March 1996. Through December 31, 1994, EPG had recovered approximately \$1.0 billion. EPG has established a reserve, based on current throughput projections, for that portion of the receivables balance which is unlikely to be collected over the period through March 1996. The balances of this reserve were \$9 million and \$19 million at December 31, 1994, and 1993, respectively.

Under FERC procedures, take-or-pay cost recovery filings may be challenged by pipeline customers on prudence and certain other grounds. In October 1992, FERC approved an order, subject to rehearing, resolving all but one of the outstanding issues regarding EPG's take-or-pay proceedings. However, certain of EPG's customers have sought review of the eligibility of certain costs for which EPG has received FERC approval for recovery. The remaining issue unresolved by FERC involved the claim by several customers that EPG sought to recover an excessive amount for the value of certain production properties which were transferred to a producer as part of a 1989 take-or-pay settlement. In June 1994, FERC affirmed a 1993 decision of an ALJ which found that the valuation proposed by EPG was excessive and required EPG to refund to its customers the costs found to be ineligible for take-or-pay recovery. In July 1994, EPG filed for rehearing of the June 1994 order. In accordance with the FERC decision, EPG refunded \$34 million, inclusive of interest, to its customers in September 1994. In November 1994, FERC issued an order which denied EPG's request for rehearing. EPG has filed a petition with the Court of Appeals for the review of the June 1994 order.

In January 1992, EPG completed a sale of substantially all of its remaining take-or-pay buy-out and buy-down receivables. The sale totaled \$325 million, including \$305 million of cash received at closing, which was used to repay \$300 million of a payable to BR. The receivables sold in this transaction included \$104 million which was recovered through direct bill and \$221 million to be recovered through volumetric surcharge. The volumetric surcharge portion of the sale has been accounted for as a financing transaction because EPG is subject to certain recourse provisions related to such receivables. At December 31, 1994, and 1993, \$47 million and \$87 million, respectively, of the volumetric surcharge portion of the receivables sold remained outstanding. Amounts collected related to the take-or-pay receivables sold are remitted to the purchasers of the receivables.

Financing and Restructuring Transactions

EPG filed a shelf registration statement in August 1994, pursuant to which EPG may offer up to \$400 million of unsecured debt securities, preferred stock, and common stock from time to time as determined by market conditions. As of December 31, 1994, EPG had not requested that the registration statement be declared effective by the Securities and Exchange Commission.

In February 1992, EPG established a $300 million revolving credit facility with a group of banks which would have expired in March 1996. This facility was replaced in August 1994 when EPG established with a group of banks a revolving credit facility of $400 million which expires in five years. As of December 31, 1994, and 1993, there were no borrowings outstanding under these facilities. Approximately $107 million and $1 million of commercial paper were outstanding as of December 31, 1994, and 1993, respectively.

During 1992, EPG completed several transactions in preparation for its separation from BR and to establish an appropriate capital structure for its post-separation operations. EPG had a Commitment Agreement with BR under which it could borrow up to $300 million and Loan Agreements for borrowings up to $500 million. The proceeds from the sale of the take-or-pay receivables, previously discussed herein, were used to repay the borrowings under the Commitment Agreement. In January 1992, EPG purchased notes and debentures totaling $134 million. Funds were provided by proceeds from borrowings under the Loan Agreements. In addition, all of the outstanding 9⅝% debentures were called for redemption at 106.84 percent of their principal amount. In January 1992, EPG received net proceeds of $569 million from the issuance of new debt securities. The proceeds were used for repayment of borrowings under the Loan Agreements, redemption of debentures, and payment of general corporate costs.

The Commitment Agreement and the Loan Agreements with BR were terminated prior to the completion of the Offering.

In January and February 1992, EPG declared and paid dividends totaling $274 million to BR. These dividends were paid from the balance owed to EPG under an intercorporate cash management arrangement. In March 1992, EPG completed the Offering. The proceeds from the Offering, net of related costs, totaled approximately $96 million. In June 1992, BR distributed its 31.4 million shares of EPG's common stock to BR shareholders, which represented approximately 85 percent of EPG's outstanding stock. As a result, BR no longer retains an ownership interest in EPG.

The Company, through a subsidiary, plans to enter into a 7.75 year lease. The lease will be an unconditional "triple net" lease with the trustee of a special purpose trust. The trust will obtain financing for construction of the plant from a consortium of financial institutions. The total amount financed via the operating lease will not exceed $80 million, and the annual lease obligation will be a function of the amount financed and a variable interest rate. The Company will have an option at the end of the lease term, and will have an obligation upon the occurrence of certain events, to purchase the plant for a price sufficient to pay the entire amount financed and accrued interest. If the Company does not purchase the plant at the end of the lease term, it will have an obligation to pay a residual guaranty amount equal to approximately 87 percent of the amount financed. Construction of the plant is expected to be completed in early 1996.

Competition

Currently, EPG faces significant competition from other companies which transport natural gas to the California market. Competition generally occurs on the basis of price, quality, and reliability of service.

The total present interstate pipeline capacity for delivering natural gas to the California border is approximately 6.9 Bcf/d. In addition to EPG, three other major interstate pipelines presently deliver natural gas to California. Transwestern has the capacity to deliver approximately 1.1 Bcf/d from Permian, Anadarko, and San Juan Basin supply sources. Kern River has the capacity to deliver approximately 700 MMcf/d from Rocky Mountain supply sources. In 1992, Kern River held an open season to determine interest in expanding capacity to California; however, they have asked FERC to postpone action on their pending certificate application which would have expanded their system capacity by 452 MMcf/d. PGT has the capacity to deliver about 1.8 Bcf/d of Canadian gas after completion of a 755 MMcf/d expansion in November 1993. This expansion consumed 500 MMcf/d of additional market that both Transwestern and EPG would have competed to serve. However, the impact of the PGT expansion to EPG in 1994 was offset by an increase in demand, which resulted from a decrease in the availability of hydroelectric power.

EPG's largest single contract for interstate capacity to California is its 1,450 MMcf/d contract with SoCal, which has a primary term ending August 31, 2006. In 1992, SoCal relinquished 300 MMcf/d pursuant to this contract (out of an original contract demand quantity of 1,750 MMcf/d), all of which was subsequently subscribed by new firm shippers under long-term contracts. Pursuant to its contract, SoCal has notified EPG of its intent to exercise its second option to relinquish an additional 300 MMcf/d of capacity on January 1, 1996. From and after the January 1, 1996 relinquishment, SoCal's contract demand quantity will remain at the 1,150 MMcf/d level for the balance of the term. PG&E has a contract for 1,140 MMcf/d of firm capacity rights on EPG's system. This contract has a primary term ending December 31, 1997. The amount of firm capacity rights, if any, that PG&E will maintain on EPG's system after the expiration of the current contract cannot be determined at this time. EPG will seek to offset future reductions in existing firm capacity commitments through new contracts with various natural gas users in California which are now served indirectly through SoCal and PG&E, as well as through the development of additional East-of-California and northern Mexico markets. In seeking new customers in California for such capacity, EPG expects to face significant competition from the other pipelines serving that state.

EPG also faces varying degrees of competition from the use of alternative energy sources, such as electricity, coal, and oil. However, competitive pressure from alternative energy sources is less prevalent in EPG's market area due to strict environmental regulations in California.

Environmental

As of December 31, 1994, EPG had a reserve of approximately $40 million for the following environmental contingencies with income statement impact:

1 — EPG has been conducting remediation of polychlorinated biphenyl ("PCB") contamination at certain of its facilities. The majority of the required PCB remediation has been completed. Future PCB remediation costs are estimated to range between $7 million and $11 million over the next 5 years.

2 — EPG executed an Administrative Order on Consent with EPA in June 1993 to conduct a Remedial Investigation/Feasibility Study ("RI/FS") for a Burlington Industries, Inc. ("BI") site located in Statesville, North Carolina, that has been identified for cleanup. BI and EPG have entered into an agreement to jointly fund the RI/FS for the site. EPG's share of the potential remediation costs is estimated to be between $17 million and $29 million over a 30 year period.

3 — In November 1993, in accordance with an EPA order, EPG and Atlantic Richfield Company ("ARCO") submitted work plans for remediation of the subsurface at the Prewitt Refinery in McKinley County, New Mexico. EPG and ARCO have a cost sharing agreement to each pay one-half of any remediation costs at this site. EPG's share of the remediation costs is estimated to be between $12 million and $20 million over a 30 year period.

4 — In December 1993, EPA issued EPG a Notice of Liability for the Colorado School of Mines Research Institute ("CSMRI") site in Golden, Colorado. EPA has determined that the volume of hazardous substances sent to the site by EPG represent less than 2.5 percent of the total volumes sent by all the potentially responsible parties ("PRPs"). Based on this percentage, EPG's share of the potential remediation costs is estimated to be less than $500,000.

5 — EPG and Texaco Exploration and Production Inc. ("Texaco") have been conducting environmental assessments of groundwater and soil contamination at various sites in southeastern Utah. Based upon currently available information, EPG estimates costs for remediation will be approximately $4 million. However, costs could be higher once the environmental assessment has been completed. EPG and Texaco are engaged in negotiations over the appropriate allocation of the remediation costs.

6 — In August 1992, EPG received a notice from the current owner of a site in Etowah, Tennessee requesting compensation for remediation expenses associated with the site. These costs are estimated to be approximately $1.7 million. EPG and the other PRP are engaged in negotiations over the appropriate allocation of the alleged costs.

7 — EPG and other PRPs entered into an agreement to conduct a RI/FS for a site located in Fountain Inn, South Carolina. The RI/FS was completed in October 1994, and EPA issued a Record of Decision for the site in November 1994. The proposed remediation and EPA oversight costs are estimated to be $800,000. The allocation of these costs between EPG and the other PRPs is currently being negotiated. EPG's share of the costs is estimated to be between $300,000 and $500,000 over a 5 year period.

8 — EPG has entered into a *de minimis* administrative order on consent with EPA for EPG's share of the environmental remediation costs associated with a site in Odessa, Texas. In accordance with the order, EPG paid total costs of approximately $32,000 in the fourth quarter of 1994.

Management believes the amount reserved as of December 31, 1994, is sufficient to cover these and other small environmental assessments and remediation activities.

The State of Tennessee has asserted a claim that EPG is a liable party under state environmental laws for cleanup costs associated with a site in Elizabethton, Tennessee. The State and EPA are in the preliminary stages of investigating the nature and extent of contamination, as well as identifying other PRPs. Since testing is in the initial stages, EPG is unable to estimate its potential share of any remediation costs.

EPG also has potential expenditures, of a capital nature, for the following environmental projects:

1 — EPG has analyzed CAAA, and believes that these rules will impact the Company's operations primarily in the following areas: (i) potential required reductions in the emissions of NOx in non-attainment areas; (ii) the requirement for air emissions permitting of existing facilities; and (iii) enhanced monitoring of air emissions. EPG anticipates capitalizing the equipment costs associated with complying with CAAA and estimates that approximately $30 million will be spent from 1995 through 2005. However, EPA's proposed enhanced monitoring rules, when finalized, could potentially impose greater costs to the Company.

2 — EPG has been conducting remediation of mercury contamination at certain facilities and is replacing mercury containing meters with other measurement devices. The project is expected to be completed in 1995 at a cost of approximately $8 million. EPG will close and retire about 1,500 earthen siphon/dehydration pits in the San Juan Basin as required by certain environmental regulations. The project is expected to be completed in 1995 at a cost of approximately $6 million. The mercury remediation and pit closure costs, which are associated with the retirement of equipment, will be recorded as adjustments to accumulated depreciation, as permitted by regulatory accounting.

It is possible that new information or future developments could require the Company to reassess its potential exposure related to environmental matters. As such information or developments occur, related accrual amounts will be adjusted accordingly.

Common Stock Transactions Subsequent to the Offering

For the years ended December 31, 1994, 1993, and 1992 EPG paid approximately $43 million, $40 million, and $19 million in dividends, respectively. In January 1995, the Board declared a quarterly dividend of $0.33 per share on EPG's common stock, payable on April 3, 1995 to shareholders of record on March 10, 1995.

In October 1992, the Board authorized the repurchase of up to two million shares of EPG's outstanding common stock from time to time in the open market. Shares repurchased are held in EPG's treasury and are expected to be used in connection with EPG employee stock option plans to minimize dilution to existing shareholders. During 1992, EPG acquired 812,773 shares of its common stock for an aggregate value of $24 million and reissued, in connection with employee stock option plans, 628,258 shares of common stock out of treasury stock for an aggregate value of $11 million. The 184,515 remaining shares were reissued through April 1993, in connection with employee stock option plans, for an aggregate value of $5 million.

During 1993, EPG acquired 509,095 shares of its common stock for an aggregate value of $18 million and subsequently reissued, in connection with employee stock option plans, 22,734 shares of its common stock out of treasury stock for an aggregate value of $0.5 million. As of December 31, 1993, EPG had 486,361 shares of treasury stock. In addition, from April 1993 through December 1993, EPG issued 43,394 shares of common stock in connection with employee stock option plans.

In November 1994, the Board authorized the repurchase of an additional 3.5 million shares of EPG's outstanding common stock from time to time in the open market. Shares repurchased are held in EPG's treasury and are expected to be used in connection with EPG employee stock option plans and for other corporate purposes. During 1994, EPG acquired 1,362,937 shares of its common stock for an aggregate value of $44 million and subsequently reissued, in connection with employee stock option plans, 50,162 shares of its common stock out of treasury stock for an aggregate value of $1.8 million. As of December 31, 1994, EPG had 1,799,136 shares of treasury stock.

A total of 800, 2,300, and 132,700 restricted shares of EPG's common stock were granted to certain employees during 1994, 1993, and 1992, respectively. The market value at grant date of such shares awarded was approximately $26,000, $76,000, and $2.8 million in 1994, 1993, and 1992, respectively.

Capital Expenditures

The Company's planned capital expenditures for 1995 of approximately $225 million are primarily for maintenance of business, system expansion, and system enhancement. These expenditures are expected to be financed through internally generated funds and short-term and long-term borrowings. Capital expenditures for 1994 were $173 million compared to $164 million for 1993. The increase was due primarily to 1994 system enhancements.

In July 1992, EPG filed an application with FERC, which was amended in November 1992, to expand the delivery capacity of its system in the vicinity of Yuma, Arizona and, through an extension of its system south to San Luis Rio Colorado, Sonora, Mexico, to serve northern Mexican markets. The proposed expansion would have provided shippers the opportunity to deliver natural gas to Mexican markets in northern Baja California via new pipeline capacity of 348 MMcf/d. The project cost was estimated to be approximately $71 million. In June 1994, EPG withdrew the July 1992 application, citing delays in the conversion to natural gas and expansion of the existing Benito Juárez Power Plant in Rosarito, Baja California Norte, Mexico. In withdrawing the pending application, EPG emphasized that it is not abandoning the project. At such time as CFE proceeds with its plans for the Benito Juárez Power Plant, EPG may refile its application.

EPG is a member of a consortium that plans to build the proposed Samalayuca II Power Plant near Ciudad Juárez, Chihuahua, Mexico. In December 1992, an award for construction was granted to the consortium by CFE. In August 1994, EPG increased its prospective ownership interest in the Samalayuca II Power Plant from 10 percent to 20 percent. CFE and the consortium signed a trust agreement in August 1994. Additional annexes to the trust agreement are currently being negotiated with CFE. The trust agreement, together with the annexes, will form the basis for seeking international financing for the Samalayuca II Power Plant project.

In March 1993, EPG filed an application with FERC to expand its system in order to provide natural gas service to the proposed Samalayuca II Power Plant and to an existing power plant in the same location. The proposed expansion would provide an additional 300 MMcf/d of capacity at a cost of approximately $57 million. In November 1993, FERC issued an order which approved the proposed border crossing facility south of Clint, Texas that would connect EPG's facilities with facilities in Mexico. FERC deferred action on the remainder of the March 1993 filing until EPG demonstrates that it has executed long-term contracts or binding precedent agreements for a substantial amount of the firm capacity of the proposed facilities. FERC required the executed contracts or agreements by January 1995. EPG has advised FERC that it does not have the contracts or agreements at this time. EPG has requested that FERC not dismiss the March 1993 application. Management believes that Mexico wants and needs this natural gas project and the process of obtaining contracts is ongoing. In December 1993, PG&E, CPUC, and SoCal jointly filed a motion with FERC seeking clarification or rehearing of the November 1993 FERC order on the Samalayuca II Power Plant project discussed above.

In April 1994, EPG filed an application with FERC for a certificate of public convenience and necessity to build a 98 mile pipeline to parallel and loop its existing Havasu Crossover Line. The proposed pipeline would allow for the transfer of 468 MMcf/d of San Juan Basin gas to EPG's south system and would enhance EPG's overall system flexibility to meet market demands. The project is expected to cost approximately $62 million. At the request of several of EPG's customers, FERC held a technical conference in August 1994 with respect to the April 1994 application. The application is currently pending before FERC.

In June 1994, EPG filed an application with FERC for a certificate of public convenience and necessity to expand its existing mainline system in the San Juan Basin by approximately 300 MMcf/d at a cost of about $26 million. At December 31, 1994, EPG had a commitment to purchase approximately $9 million of pipe in connection with the proposed expansion. The proposed expansion would accommodate increased volumes and provide markets with enhanced access to San Juan Basin gas supplies. FERC held a technical conference in August 1994 with respect to the June 1994 application. The application is currently pending before FERC.

In March 1993, MPC filed an application, which was amended in November 1993 and April 1994, for a certificate of public convenience and necessity to build and operate a 475 MMcf/d expansion of its existing system at an estimated cost of approximately $500 million.

In December 1993, FERC held a public conference to examine the question raised by CPUC and PG&E regarding MPC's proposed expansion. The primary issue was whether FERC or CPUC should have jurisdiction over the expansion. In February 1994, FERC issued an order determining that it has exclusive jurisdiction over MPC and its proposed expansion. In March 1994, CPUC, PG&E, and other parties filed for rehearing or clarification of FERC's February 1994 order. The petitions for rehearing and/or clarification are pending action by FERC. In November 1994, FERC unanimously approved an order granting MPC a preliminary determination, subject to possible later modification, issuing the requested certificate of public convenience and necessity for the proposed expansion. FERC requested certain further information from the parties to determine whether PG&E, which is currently the principal gas supplier in the region to be served by the expansion project, is entitled to any compensation from MPC and/or EPG as a result of MPC's bypass of PG&E gas service. MPC and EPG have provided FERC with the requested information. The preliminary determination did not address the jurisdictional issues pending before FERC on rehearing of the February 1994 order. In December 1994, MPC and other parties filed requests for rehearing of the preliminary determination asking for reconsideration of rate and other modifications ordered by FERC. If FERC does not make significant changes to the preliminary determination, MPC will not go forward with the expansion. MPC expects to receive a final FERC certificate in the second quarter of 1995.

The capital projects discussed above are expected to be financed through internally generated funds and short-term and long-term borrowings.

Other

In January 1993, EPG experienced flood damage to its pipeline system in the Gila, Arizona area due to heavy rain. During 1994, EPG received approximately $22 million of insurance reimbursements, which represent substantially all costs incurred related to the flood damage.

In June 1994, EPG and Meridian Oil Production Inc. ("MOPI") entered into an agreement concerning production from MOPI's conventional gas wells located on 1.5 million acres in the San Juan Basin. Under the terms of the agreement, MOPI's gas is committed to flow exclusively through EPG's gathering and processing facilities from May 1994 through February 2000. The agreement provides for new rates for gathering and processing of natural gas liquids effective January 1, 1994 through February 29, 2000.

Results of Operations

Year Ended December 31, 1994, Compared to Year Ended December 31, 1993

Operating revenues for the year ended December 31, 1994, were $39 million lower than for the same period of 1993. New system rates that became effective January 1, 1994, resulted in lower reservation revenues of $28 million and lower transportation revenues of $28 million. Additionally, lower gas sales rates, lower gas sales volumes, and the 1993 sale of gas in storage contributed $25 million, $12 million, and $18 million, respectively, to the decrease to operating revenues. The decrease due to the 1993 sale of gas in storage is offset in operating charges. Lower accruals for regulatory issues, the consolidation of MPC, and higher rates for gathering and processing offset the decrease in operating revenues by $41 million, $18 million, and $15 million, respectively.

Operating charges were $32 million lower for the year ended December 31, 1994, than for the same period of 1993. Lower gas sales volumes and the 1993 sale of gas in storage contributed $11 million and $18 million, respectively, to the decrease in operating charges. The decrease due to the 1993 sale of gas in storage is offset in operating revenues. Additionally, operation and maintenance expense decreased primarily due to a 1993 accrual for estimated take-or-pay undercollections, a 1993 litigation settlement, lower plant and pipeline maintenance, 1994 adjustments to the 1993 take-or-pay undercollections accrual, and lower environmental cleanup expenses. Offsetting the decrease in operating charges was a litigation special charge of $15 million related to the *Amoco* decision. In addition, higher average cost of gas, an increase in depreciation expense, and the consolidation of MPC further offset the decrease in operating charges by $15 million, $8 million, and $9 million respectively.

Interest and debt expense for the year ended December 31, 1994, was $3 million higher than for the same period of 1993 due primarily to the consolidation of MPC.

Allowance for funds used during construction ("AFUDC") was $5 million lower for the year ended December 31, 1994, than for the same period of 1993 due primarily to a decrease in the average construction work in progress balance.

Other-net income was $13 million higher for the year ended December 31, 1994, than for the same period of 1993. Contributing to the higher other income in 1994 were $14 million related to the recovery of EPG's investment in its underground storage facility and lower environmental clean-up expenses. The increase in other income was partially offset by interest expense related to the special charge for litigation in connection with the *Amoco* decision of approximately $4 million, and a reduction in partnership earnings due to the consolidation of MPC.

EPG's mainline throughput for the year ended December 31, 1994, was 1,326 Bcf compared to 1,306 Bcf for the same period of 1993. Throughput was higher due to an increase in deliveries to off-system and East-of-California markets. The increase in throughput was partially offset by lower deliveries to the California market due to higher storage withdrawals and increased competition. Gathered volumes for the year ended December 31, 1994, were relatively unchanged compared to the same period of 1993.

Year Ended December 31, 1993, Compared to Year Ended December 31, 1992

Operating revenues for the year ended December 31, 1993, were $106 million higher than for the same period of 1992. New system rates and a new rate design placed into effect February 1, 1993, resulted in a $41 million increase in revenues which was comprised of an increase in reservation revenues of $111 million offset by a decrease in transportation revenues of $70 million. The consolidation of MPC contributed $27 million to the increase. Higher rates and volumes for gathering and processing increased revenues by $3 million and $7 million, respectively. Higher sales rates increased revenues by $34 million; however, lower sales volumes offset that increase by $5 million. In addition, the sale of gas in storage contributed $18 million to the increase in revenues; this increase is offset in operating charges. Offsetting the increase in operating revenues was a decrease of $13 million due to lower transportation volumes, a decrease in return on take-or-pay receivables of $4 million, and a decrease in liquid revenues of $2 million.

Operating charges were $62 million higher for the year ended December 31, 1993, compared to the same period for 1992. Higher average cost of gas contributed $39 million to the increase. In addition, the sale of gas in storage contributed $18 million to the increase in operating charges; this increase is offset in operating revenues. Higher operation and maintenance costs of $26 million were due primarily to an accrual for estimated take-or-pay undercollections, the consolidation of MPC, and increases in employee benefit costs and outside contractors fees, primarily related to environmental clean-up. This increase is partially offset by lower stock related benefit costs. An increase of $3 million in other taxes is primarily due to the consolidation of MPC and an increase in ad valorem taxes. The increase in operating charges was partially offset by lower depreciation rates after giving effect to the rate settlement. Additionally, lower gas sales volumes resulted in a decrease in operating charges of $4 million.

Interest and debt expense for the year ended December 31, 1993, was $7 million higher than for the same period of 1992 due primarily to the consolidation of MPC.

AFUDC was $2 million lower for the year ended December 31, 1993, than for the same period in 1992 due to a decrease in expansion project expenditures during 1993.

Other-net was $6 million higher for the year ended December 31, 1993, compared to the same period for 1992. Contributing to the higher expense was a $6 million increase related to environmental accruals; a $4 million reduction in direct bill interest income; and a $4 million reduction in partnership earnings due to the consolidation of MPC. The increase was offset by lower interest expense of $4 million on tax adjustments and $3 million of interest income related to the recovery of EPG's investment in its underground storage facility.

EPG's throughput for 1993 was 1,306 Bcf compared to 1,357 Bcf in 1992. This decrease is due to lower deliveries to the utility electric generation market resulting from the availability of excess hydroelectric power in the California markets. The lower deliveries to California were partially offset by higher throughput to off-system markets.

Other

The Financial Accounting Standards Board issued *Statement of Financial Accounting Standards* ("SFAS") No. 106 which requires companies to account for other postretirement employee benefits ("OPEBs") (principally retiree medical costs) on an accrual basis versus the pay-as-you-go basis traditionally followed by most United States companies. The Company adopted SFAS No. 106 effective January 1, 1993.

The Company provides a non-contributory defined benefit postretirement medical plan that covers employees who retired on or before March 1, 1986, and limited postretirement life insurance for employees who retire after January 1, 1985. As such, the Company's obligation to accrue for OPEBs is primarily limited to the fixed population of retirees who retired on or before March 1, 1986. The medical plan is funded to the extent employer contributions are recoverable through rates.

EPG began recovering through its rates the OPEB costs included in the settlement agreement. To the extent actual OPEB costs differ from the amounts funded, a regulatory asset or liability is recorded. Management expects to seek inclusion of such amounts in its rates.

The Financial Accounting Standards Board issued SFAS No. 112 which requires companies to account for benefits to former or inactive employees after employment but before retirement (referred to in SFAS No. 112 as "postemployment benefits"). SFAS No. 112 is effective for the fiscal years beginning after December 15, 1993. These postemployment benefits include every form of benefit provided to former or inactive employees, their beneficiaries, and covered dependents. Benefits include, but are not limited to salary continuation, supplemental unemployment benefits, severance benefits, disability-related benefits (including workers' compensation), job training and counseling, and continuation of benefits such as health care benefits and life insurance coverage. Effective January 1, 1994, the Company adopted SFAS No. 112. The Company has recorded a liability for postemployment benefit costs of approximately $8 million to reflect the initial adoption of SFAS No. 112. Management expects to seek recovery of the $8 million through rates and has recorded a regulatory asset equal to that amount.

Deferred credits, in the Consolidated Balance Sheet, include excess deferrals resulting from the reduction of the statutory federal tax rate from 46 to 34 percent on July 1, 1987. Regulatory assets in the Consolidated Balance Sheet include expected future recoveries resulting from the increase of the statutory federal rate from 34 to 35 percent on January 1, 1993. Management expects to seek recovery of such amounts through its rates.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EL PASO NATURAL GAS COMPANY

CONSOLIDATED STATEMENT OF INCOME
(In thousands, except per common share amounts)

	Year Ended December 31,		
	1994	1993	1992
Operating revenues			
Reservation	$506,122	$483,471	$346,027
Transportation	41,102	59,631	141,789
Gas and liquid sales	225,857	280,839	237,965
Gathering and processing	66,581	51,427	41,759
Other	30,210	33,560	35,272
	869,872	908,928	802,812
Operating charges			
Operation and maintenance	295,182	340,818	314,782
Natural gas and liquids	233,823	249,484	197,759
Depreciation and amortization	65,037	54,051	73,229
Litigation special charge	15,062	—	—
Taxes, other than income taxes	38,473	35,330	32,132
	647,577	679,683	617,902
Operating income	222,295	229,245	184,910
Other (income) and income deductions			
Interest and debt expense	78,850	75,429	68,075
Allowance for funds used during construction	(485)	(5,438)	(7,096)
Interest income from BR	—	—	(1,602)
Other — net	(4,146)	8,428	2,244
	74,219	78,419	61,621
Income before income taxes	148,076	150,826	123,289
Income taxes	58,463	59,153	46,963
Net income	$ 89,613	$ 91,673	$ 76,326
Earnings per common share	$ 2.45	$ 2.46	$ 2.12
Average common shares outstanding	36,632	37,212	36,049

The accompanying Notes and Supplemental Schedules are an integral part of these Consolidated Financial Statements.

EL PASO NATURAL GAS COMPANY

CONSOLIDATED BALANCE SHEET
(In thousands, except per share amount)

ASSETS

	December 31, 1994	December 31, 1993
Current assets		
Cash and temporary investments	$ 27,636	$ —
Accounts and notes receivable, net	131,650	133,437
Materials and supplies inventory	34,666	34,665
Take-or-pay buy-outs, buy-downs, and prepayments, net	33,356	34,019
Other regulatory assets	12,000	12,000
Deferred income tax benefit	41,257	44,141
Costs recoverable through insurance	291	23,260
Other	18,303	22,490
Total current assets	299,159	304,012
Property, plant, and equipment, net	1,865,897	1,765,486
Take-or-pay buy-outs, buy-downs, and prepayments, net	14,502	48,106
Other regulatory assets	59,021	62,249
Other	93,192	89,810
	2,032,612	1,965,651
Total assets	$2,331,771	$2,269,663

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 1994	December 31, 1993
Current liabilities		
Accounts payable		
Trade	$ 117,575	$ 125,944
Other	111,781	73,939
Commercial paper	106,800	1,300
Take-or-pay financing liability	36,700	40,125
Accrual for regulatory issues	—	47,263
Current maturities of long-term debt	6,824	6,184
Accrued interest	31,236	30,447
Accrued taxes, other than income taxes	27,373	21,135
Other	13,766	10,127
Total current liabilities	452,055	356,464
Long-term debt, less current maturities	779,097	795,783
Deferred income taxes, less current portion	304,918	298,080
Take-or-pay financing liability, less current portion	—	40,383
Deferred credits	40,325	25,540
Other liabilities	45,740	45,865
	1,170,080	1,205,651
Commitments and contingent liabilities (see Notes 2, 4, and 13)		
Stockholders' equity		
Common stock, par value $3 per share; authorized, 100,000 shares; issued, 37,351 shares and 37,350 shares	112,053	112,051
Additional paid-in capital	454,705	455,496
Retained earnings	202,558	157,506
Less: Treasury stock 1,799 shares and 486 shares	59,680	17,505
Total stockholders' equity	709,636	707,548
Total liabilities and stockholders' equity	$2,331,771	$2,269,663

The accompanying Notes and Supplemental Schedules are an integral part of these Consolidated Financial Statements.

EL PASO NATURAL GAS COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	1994	1993	1992
Cash flows from operating activities			
Income from operations	$ 89,613	$ 91,673	$ 76,326
Adjustments to reconcile income to net cash provided by operating activities			
Depreciation and amortization	65,037	54,051	73,229
Deferred income taxes	49,394	8,550	(54,468)
Net take-or-pay recoveries	31,932	60,799	213,748
Costs recovered (recoverable) through insurance	22,969	(22,578)	1,096
Other working capital changes			
Accounts and notes receivable	862	34,877	7,215
Inventories	(2,527)	11,530	3,700
Other current assets	4,684	10,209	(16,707)
Accounts payable	33,322	(38,644)	17,680
Accrual for regulatory issues	(34,903)	1,210	15,267
Accrued taxes, other than income taxes	4,132	5,291	4,566
Other current liabilities	(4,037)	3,609	(24,693)
Other	(7,276)	14,975	16,579
Net cash provided by operating activities	253,202	235,552	333,538
Cash flows from investing activities			
Capital expenditures	(173,252)	(164,333)	(245,799)
Mojave acquisition	—	(35,695)	—
Proceeds from property dispositions	7,299	1,674	4,812
Other	(23,381)	(7,553)	(2,111)
Net cash used in investing activities	(189,334)	(205,907)	(243,098)
Cash flows from financing activities			
Proceeds from sale of common stock, net	26	947	95,557
Proceeds from reissuance of treasury stock	1,204	3,869	10,754
Proceeds from long-term financings	—	—	575,000
Long-term debt retirements	(16,174)	(2,871)	(186,416)
Net commercial paper borrowings	105,500	1,300	—
Proceeds from sale of volumetric take-or-pay receivables	—	—	210,621
Repayment of volumetric take-or-pay receivable	(43,808)	(35,313)	(94,800)
Repayment of payable to BR	—	—	(624,804)
Acquisition of treasury stock	(43,994)	(18,001)	(23,988)
Dividends paid prior to initial public offering	—	—	(274,000)
Dividends paid subsequent to initial public offering	(43,491)	(39,935)	(18,651)
Other	4,505	11,721	(35,846)
Net cash used in financing activities	(36,232)	(78,283)	(366,573)
Increase (decrease) in cash and temporary cash investments	27,636	(48,638)	(276,133)
Cash and temporary cash investments			
Beginning of period	—	48,638	324,771
End of period	$ 27,636	$ —	$ 48,638

The accompanying Notes and Supplemental Schedules are an integral part of these Consolidated Financial Statements.

EL PASO NATURAL GAS COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(Dollars in thousands, except per share amounts)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Treasury Stock		Total Stockholders' Equity
	Shares	Amount			Shares	Amount	
January 1, 1992	31,421,731	$ 94,265	$382,260	$ 338,353		$ —	$ 814,878
Net income				76,326			76,326
Issuance of common stock, net of related costs	5,882,700	17,648	72,220				89,868
Common stock dividends, prior to the Offering				(274,000)			(274,000)
Common stock dividends, subsequent to the Offering ($.75 per share)				(27,817)			(27,817)
Acquisition of treasury stock					(812,773)	(23,988)	(23,988)
Reissuance of treasury stock				(4,837)	628,258	18,562	13,725
December 31, 1992	37,304,431	111,913	454,480	108,025	(184,515)	(5,426)	668,992
Net income				91,673			91,673
Issuance of common stock, net of related costs	45,694	138	1,016				1,154
Common stock dividends, ($1.10 per share)				(40,904)			(40,904)
Acquisition of treasury stock					(509,095)	(18,001)	(18,001)
Reissuance of treasury stock				(1,288)	207,249	5,922	4,634
December 31, 1993	37,350,125	112,051	455,496	157,506	(486,361)	(17,505)	707,548
Net income				89,613			89,613
Issuance of common stock, net of related costs	800	2	24				26
Common stock dividends, ($1.21 per share)				(44,179)			(44,179)
Acquisition of treasury stock					(1,362,937)	(43,994)	(43,994)
Reissuance of treasury stock				(382)	50,162	1,819	1,437
Other			(815)				(815)
December 31, 1994	37,350,925	$112,053	$454,705	$ 202,558	(1,799,136)	$(59,680)	$ 709,636

The accompanying Notes and Supplemental Schedules are an integral part of these Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Company. All significant intercompany transactions are accounted for at market prices and have been eliminated in consolidation. The financial statements for previous periods include certain reclassifications that were made to conform to the current presentation. Such reclassifications have no impact on reported income or stockholders' equity.

On June 1, 1993, the Company acquired from a wholly owned subsidiary of Enron Corp., that subsidiary's 50 percent interest in MPC, a general partnership. This acquisition gave the Company 100 percent ownership of MPC. The operating results of MPC are included in the Company's consolidated results of operations for 1994 and the months of May 1993 through December 1993. The Company's previously owned 50 percent equity interest in MPC is included in other-net in the Consolidated Statement of Income.

Accounting for Regulated Operations

EPG and MPC are subject to the regulations and accounting procedures of FERC and therefore, continue to follow the reporting and accounting requirements of SFAS No. 71. Accounting methods for companies subject to cost-of-service regulation may differ from those used by non-regulated companies. However, when the accounting method prescribed by the regulatory authority is used for rate-making, such accounting conforms to the generally accepted accounting principle of matching costs against the revenues to which they apply.

Transactions which EPG has recorded differently than a non-regulated entity include the following: (i) take-or-pay payments recoverable from customers, based upon transportation volumes, have been recorded as an asset, net of allowance; (ii) losses on reacquired debt have been recorded in other assets and are being amortized over the life of the original or replacement debt; (iii) revenue related to the implementation of SFAS No. 109 has been recorded as a deferred credit and is being amortized into income; (iv) adjustment to reflect the increase in the federal income tax rate has been recorded in other regulatory assets to be recovered in future rates; (v) OPEB costs that differ from the amounts funded are recorded either as a regulatory asset or liability to be included in future rates; (vi) postemployment benefit costs have been recorded in other regulatory assets to be recovered in future rates; (vii) a portion of EPG's investment in its underground storage facility has been recorded as an asset and is being recovered in accordance with the settlement agreement; and (viii) the cost of equity funds used during construction has been capitalized.

Transactions which MPC has recorded differently than a non-regulated entity include the following: (i) the cost of equity funds used during construction has been capitalized; (ii) excess amounts due to straight-line depreciation rates have been recorded as other regulatory assets to be recovered in future rates; and (iii) deferred taxes on the equity portion of AFUDC have been recorded in other regulatory assets to be recovered in future rates.

Management believes that MPC remains "regulated" as the term is used in the relevant accounting literature. However, management is currently evaluating whether or not the application of these principles will continue to be appropriate for MPC in the future. At December 31, 1994, the Consolidated Balance Sheet contains assets and liabilities related to MPC's operations which have been recorded pursuant to regulatory accounting principles. If these accounting principles should no longer be applied to MPC's operations, an amount would be charged to earnings as an extraordinary item. At December 31, 1994, this amount was estimated to be approximately $8 million.

Cash and Temporary Investments

Short-term investments purchased with an original maturity of three months or less are considered cash equivalents.

Accumulated Provision for Uncollectible Accounts Receivable

The Company has established a provision for losses on trade accounts receivable which may become uncollectible. Collectibility of trade receivables is reviewed regularly, and the allowance for bad debts is adjusted as necessary under the specific identification method. The balances of this provision at December 31, 1994, and 1993 were $6.2 million and $3.9 million, respectively.

Gas Imbalances

The Company currently accounts for gas imbalances due to or due from shippers and operators. Gas imbalances are valued at the appropriate index price.

The Company has established a provision for gas imbalances which may become uncollectible. Collectibility of gas imbalances is reviewed regularly and the provision is adjusted as necessary under the specific identification method. The balances of the provision at December 31, 1994, and 1993 were $8.8 million and $5.6 million, respectively.

Materials and Supplies Inventory

Inventory is valued at cost and relieved using the average cost method.

Take-or-Pay Settlements

Assets resulting from the resolution of take-or-pay obligations include recoupable take-or-pay prepayments and take-or-pay buy-out and buy-down receivables. Recoupable prepayments result when EPG pays for, but does not physically receive, gas and retains the right to take such gas in the future, generally over five years. Take-or-pay buy-outs and buy-downs represent costs paid to natural gas producers for the termination or modification of gas purchase contracts. In exchange for EPG's agreement to absorb 25 percent of its take-or-pay buy-out and buy-down costs, FERC regulations provide for the direct billing of 25 percent of such costs to EPG's customers. In addition, such regulations allow EPG to recover the remaining 50 percent of its buy-out and buy-down costs through a surcharge added to its transportation rates.

Property, Plant, and Equipment

Included in the Company's property, plant, and equipment is construction work in progress of approximately $78 million and $53 million at December 31, 1994, and 1993, respectively. An allowance for both debt and equity funds used during construction is included in the cost of the Company's property, plant, and equipment.

EPG's properties are depreciated using the composite method. The straight-line depreciation rate for 1994 and 1993 was 1.6 percent for transmission facilities. For 1992, the depreciation rate for transmission facilities was 2.67 percent adjusted to 1.6 percent in accordance with the settlement agreement. The depreciation rate for gathering facilities was 3.5 percent for 1994, 1993, and 1992.

MPC's depreciation rates reflect a levelized cost-of-service approach and a 25-year depreciable life. MPC's depreciation rate for its plant during the first 15 years increases gradually from 1.48 percent in 1992 to 8.76 percent in 2007. The depreciation rates are designed to recover approximately 80 percent of MPC's plant balance by March 1, 2007. The depreciation rate related to years 16 through 25 will be determined in future rate proceedings. (See "*Accounting for Regulated Operations*" of this note.)

Additional acquisition cost assigned to utility plant represents EPG's portion of the excess of allocated acquisition cost over historical cost that resulted from the 1983 acquisition of EPG's former parent, TEPCO, by BR's former parent, Burlington Northern Inc. ("BNI"). These costs are being amortized on a straight-line basis over the estimated remaining life of the properties.

Costs of properties that are not operating units, as defined by FERC, which are retired, sold or abandoned are charged or credited, net of salvage, to accumulated depreciation and amortization. Gains or losses on sales of operating units are credited or charged to income.

Environmental Costs

Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to existing conditions caused by past operations and that do not contribute to current or future revenue generation are expensed. Reserves for estimated costs are recorded when environmental remedial efforts are probable and the costs can be reasonably estimated. The most current information available, including similar past experiences, available technology, regulations in effect, the timing of remediation, and cost-sharing arrangements are used in determining the reserves. The environmental reserves are based on management's estimate of the most likely cost to be incurred and are reviewed periodically and adjusted as additional or new information becomes available.

Financial Instruments With Off-Balance-Sheet Risk

The Company is a party to financial instruments with off-balance-sheet risk in the normal course of business to reduce its exposure to fluctuations in interest rates and the price of natural gas. These financial instruments include interest rate swaps, price swap agreements, futures, and options.

Gains or losses on futures and options contracts are deferred until the hedged commodity transaction occurs. The difference paid or received under the interest rate swap agreements is charged or credited to interest expense. Gains or losses on price swaps, futures, and options are recognized and reported as a component of the related transaction. Any cash flow activities resulting from holding these financial instruments are treated in the same manner as the underlying instrument.

Income Taxes

Income taxes are based on income reported for tax return purposes and 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.

Pursuant to a tax sharing agreement between EPG and BR covering periods prior to July 1992, EPG is responsible for its tax liabilities and those of its subsidiaries. EPG is required to pay BR its allocable portion of the consolidated federal tax liability and combined state income tax liability.

Treasury Stock

Treasury stock is accounted for using the cost method and is shown as a reduction to stockholders' equity in the Consolidated Balance Sheet. Treasury stock sold or reissued is valued on a first-in first-out basis. Included in treasury stock at December 31, 1994, are 430,000 shares that have been used to secure benefits under certain of the Company's benefit plans.

Earnings Per Share

Earnings per share of common stock is based on the weighted average number of shares of common stock outstanding during the year. The weighted average shares of common stock outstanding for 1994, 1993, and 1992 were 36,632,236, 37,212,192, and 36,049,135, respectively. Stock options are the only common stock equivalents and are currently not dilutive.

2. RATES AND REGULATORY MATTERS

General Rate Filings and Other

In July 1991, EPG filed for FERC approval of new system rates and placed the proposed new rates into effect on January 1, 1992, subject to refund. In July 1992, EPG again filed for new rates to recover increased costs and return on rate base associated with EPG's expansion and modernization projects. These rates became effective on February 1, 1993, subject to refund. In the July 1992 filing, EPG's rate base increased from $752 million to approximately $1.2 billion. EPG made its compliance filing in December 1992, in accordance with the Restructuring Rules.

In January 1993, EPG, certain of its customers, and FERC staff reached a settlement agreement which led to the resolution of the above mentioned rate and restructuring proceedings. The settlement agreement was filed in January 1993 to supersede EPG's December 1992 compliance filing. As required by the FERC order, EPG filed revised rates in September 1993, which implemented the settlement agreement effective October 1, 1993. Under the settlement agreement, EPG refunded a total of approximately $56 million, inclusive of interest, in the fourth quarter of 1993. EPG had provided for these rate refunds as revenues were collected.

The settlement agreement provided, in part, for the accelerated recovery of a substantial portion of EPG's investment in its underground storage facility. The amount to be recovered was approximately $56.7 million plus interest which began accruing February 1, 1993, at the FERC allowed rate, which approximates the prime rate. In March 1994, EPG received a final FERC letter order approving recovery of the $56.7 million of underground storage facility costs. Such costs are being recovered through December 31, 1996, by a demand charge mechanism. The amount recovered through December 31, 1994 was $32 million. The outstanding balances at December 31, 1994, and 1993 were $24 million and $37 million, respectively, of which $12 million is reflected in the current portion of other regulatory assets for both periods and $12 million and $25 million, respectively, are included in other regulatory assets in the Consolidated Balance Sheet. The settlement agreement also established new depreciation rates for certain of EPG's facilities effective January 1, 1992.

MPC filed a service and rate design restructuring plan in November 1992 in compliance with FERC's industry-wide Restructuring Rules. In March 1993, FERC issued an order essentially approving MPC's compliance filing, subject to changes, which were made in an amended restructuring plan in March 1993.

Several of MPC's customers filed protests and requests for rehearing of the March 1993 FERC order. The rehearing requests were denied, and FERC approved the amended restructuring plan in July 1993 with an effective date of August 1, 1993. In October 1993, FERC issued an order which denied requests for rehearing of the July 1993 order. Several of MPC's customers have filed petitions with the Court of Appeals for review of the March 1993, July 1993, and October 1993 orders. These petitions are currently pending before the Court of Appeals. The primary issues on appeal pertain to FERC's requirement that MPC's rates for firm transportation service be based upon SFV rate design rather than MFV rate design. The application of SFV rates requires MPC's existing firm shippers to pay a higher proportion of their total transportation rate in the reservation component of the rate. Such shippers have contended that FERC's application of SFV rate design to MPC unlawfully abrogates the rate provisions of MPC's service agreements and constitutes an unlawful rate increase. Management believes the Court of Appeals will uphold SFV rates as applied to MPC.

Producer Settlement and Cost Recovery

Since 1987, EPG has made, or has committed to make, buy-out and buy-down payments totaling $1.5 billion to resolve past and future take-or-pay exposure, to terminate and reform gas purchase contracts, to amend pricing and take provisions of gas purchase contracts, and to settle related litigation. These payments resolved virtually all the outstanding producer claims asserted against EPG and terminated or prospectively reformed substantially all of EPG's remaining gas purchase contracts, with the result that EPG no longer has any material take-or-pay exposure. In certain cases, EPG resolved claims by making recoupable prepayments. At December 31, 1994, and 1993, the recoupable prepayment balances were $6 million and $9 million, respectively.

EPG has filed to recover $1.1 billion of its buy-out and buy-down costs under FERC cost recovery procedures. The collection period for such costs extends through March 1996. Through December 31, 1994, EPG had recovered approximately $1.0 billion. EPG has established a reserve, based on current throughput projections, for that portion of the receivables balance which is unlikely to be collected over the period through March 1996. The balances of this reserve were $9 million and $19 million at December 31, 1994, and 1993, respectively.

Under FERC procedures, take-or-pay cost recovery filings may be challenged by pipeline customers on prudence and certain other grounds. In October 1992, FERC approved an order, subject to rehearing, resolving all but one of the outstanding issues regarding EPG's take-or-pay proceedings. However, certain of EPG's customers have sought review of the eligibility of certain costs for which EPG has received FERC approval for recovery. The remaining issue unresolved by FERC involved the claim by several customers that EPG sought to recover an excessive amount for the value of certain production properties which were transferred to a producer as part of a 1989 take-or-pay settlement. In June 1994, FERC affirmed a 1993 decision of an ALJ which found that the valuation proposed by EPG was excessive and required EPG to refund to its customers the costs found to be ineligible for take-or-pay recovery. In July 1994, EPG filed for rehearing of the June 1994 order. In accordance with the FERC decision, EPG refunded $34 million, inclusive of interest, to its customers in September 1994. In November 1994, FERC issued an order which denied EPG's request for rehearing. EPG has filed a petition with the Court of Appeals for the review of the June 1994 order.

In January 1992, EPG completed a sale of substantially all of its remaining take-or-pay buy-out and buy-down receivables. The sale totaled $325 million, including $305 million of cash received at closing, which was used to repay $300 million of a payable to BR. The receivables sold in this transaction included $104 million which was recovered through direct bill and $221 million to be recovered through volumetric surcharge. The volumetric surcharge portion of the sale has been accounted for as a financing transaction because EPG is subject to certain recourse provisions related to such receivables. At December 31, 1994, and 1993, $47 million and $87 million, respectively, of the volumetric surcharge portion of the receivables sold remained outstanding. Amounts collected related to the take-or-pay receivables sold are remitted to the purchasers of the receivables.

3. LONG-TERM DEBT AND OTHER FINANCING

Long-term debt outstanding is as follows:

	December 31, 1994	December 31, 1993
	(In thousands)	
Long-term debt		
EPG		
6.90% Notes, due January 1997	$100,000	$100,000
9.45% Notes, due September 1999	47,447	47,442
7¾% Notes, due January 2002	214,624	214,570
8⅝% Debentures, due March 2012	16,811	16,791
8⅝% Debentures, due January 2022	258,420	258,362
Other	35	43
MPC		
Project financing loan, due March 2007, average interest rates of 8.0% and 7.6%	148,584	164,759
	785,921	801,967
Less current maturities	6,824	6,184
Total long-term debt	$779,097	$795,783

The following are aggregate maturities of long-term debt for the next five years and in total thereafter:

	(In thousands)
1995	$ 6,824
1996	7,517
1997	108,279
1998	18,081
1999	65,366
Thereafter	579,854
Total long-term debt, including current maturities	$785,921

In January 1992, EPG completed a purchase of $46 million and $41 million of aggregate principal amounts of the 9.45% Notes and 8⅝% Debentures, respectively. Funds for these purchases were provided by proceeds from borrowings under the BR Loan Agreements described below. In addition, in December 1991 EPG called for redemption, on January 23, 1992, of all the outstanding 9⅝% Debentures ($100 million aggregate principal amount) at a price equal to 106.84 percent of their principal amount.

EPG had a Commitment Agreement with BR under which it could borrow up to $300 million and Loan Agreements for borrowings up to $500 million. Proceeds from the sale of the take-or-pay receivables were used to repay the borrowings under the Commitment Agreement. In January 1992, EPG borrowed $109 million under the Loan Agreements. Borrowings under the Loan Agreements were used to pay for the purchase of the 9.45% Notes and the 8⅝% Debentures in January 1992 and the payment of related transaction costs.

In January 1992, EPG issued $575 million principal amount of new debt securities consisting of $100 million of 6.90% Notes due 1997, $215 million of 7¾% Notes due 2002, and $260 million of 8⅝% Debentures due 2022. The net proceeds of $569 million received from such issuance were used to repay $434 million of borrowings under the Loan Agreements with BR, to redeem $107 million of 9⅝% Debentures, and for general corporate purposes ($28 million) including costs related to the transactions discussed above. The Commitment Agreement and the Loan Agreements with BR were terminated prior to the completion of the Offering.

In February 1992, EPG established a $300 million revolving credit facility with a group of banks which would have expired in March 1996. This facility was replaced in August 1994 when EPG established with a group of banks a revolving credit facility of $400 million which expires in five years. As of December 31, 1994, and 1993, respectively, there were no borrowings outstanding under these facilities. Approximately $107 million and $1 million of commercial paper were outstanding as of December 31, 1994, and 1993, respectively. The weighted average interest rates on these borrowings for 1994 and 1993 were 4.58 percent and 3.24 percent, respectively.

EPG must comply with various restrictive covenants contained in its debt agreements which include, among others, maintaining a consolidated debt and guaranties to capitalization ratio no greater than 70 percent. Also, EPG must maintain consolidated tangible net worth of at least $400 million. Furthermore, certain EPG subsidiaries (other than any project financing subsidiary, as defined in the agreements) may not incur debt obligations which would exceed $75 million in the aggregate. As of December 31, 1994, EPG's consolidated debt and guaranties to capitalization ratio was 51.2 percent, its consolidated tangible net worth exceeded the minimum restrictive covenant requirement by approximately $300 million, and there were no subsidiary debt obligations of those subsidiaries limited by the debt agreements.

EPG filed a shelf registration statement in August 1994 pursuant to which EPG may offer up to $400 million of unsecured debt securities, preferred stock, and common stock from time to time as determined by market conditions. As of December 31, 1994, EPG had not requested that the registration statement be declared effective by the Securities and Exchange Commission.

In September 1991, MPC entered into a credit agreement ("Credit Agreement") with a group of banks which provided a 15 year project financing loan to MPC of up to $180 million. Total outstanding loan balances under the Credit Agreement were $149 million and $165 million at December 31, 1994, and 1993, respectively. The loan is repayable in semiannual installments through March 2007. Interest on the loan is payable quarterly.

Borrowings under the Credit Agreement are collateralized by a priority interest in the Company's partnership interests and certain other distributed and undistributed partnership property. The Credit Agreement also contains covenants relating to, among other things, partnership distributions and additional indebtedness.

MPC has entered into interest rate swap agreements which effectively convert $114.3 million of the current loan balance from floating-rate debt to fixed-rate debt. MPC makes payments to counterparties at fixed rates and in return receives payments at floating rates. Substantially all of the remaining $34.3 million of loan principal had interest rates ranging from 4.1 percent to 6.0 percent during 1994. With the impact of the interest rate swap agreements, the overall effective interest rates on the loan were approximately 8.0 percent and 7.6 percent during 1994 and 1993, respectively.

4. ENVIRONMENTAL

As of December 31, 1994, EPG had a reserve of approximately $40 million for the following environmental contingencies with income statement impact:

1 — EPG has been conducting remediation of PCB contamination at certain of its facilities. The majority of the required PCB remediation has been completed. Future PCB remediation costs are estimated to range between $7 million and $11 million over the next 5 years.

2 — EPG executed an Administrative Order on Consent with EPA in June 1993 to conduct a RI/FS for a BI site located in Statesville, North Carolina, that has been identified for cleanup. BI and EPG have entered into an agreement to jointly fund the RI/FS for the site. EPG's share of the potential remediation costs is estimated to be between $17 million and $29 million over a 30 year period.

3 — In November 1993, in accordance with an EPA order, EPG and ARCO submitted work plans for remediation of the subsurface at the Prewitt Refinery in McKinley County, New Mexico. EPG and ARCO have a cost sharing agreement to each pay one-half of any remediation costs at this site. EPG's share of the remediation costs is estimated to be between $12 million and $20 million over a 30 year period.

4 — In December 1993, EPA issued EPG a Notice of Liability for the CSMRI site in Golden, Colorado. EPA has determined that the volume of hazardous substances sent to the site by EPG represent less than 2.5 percent of the total volumes sent by all PRPs. Based on this percentage, EPG's share of the potential remediation costs is estimated to be less than $500,000.

5 — EPG and Texaco have been conducting environmental assessments of groundwater and soil contamination at various sites in southeastern Utah. Based upon currently available information, EPG estimates costs for remediation will be approximately $4 million. However, costs could be higher once the environmental assessment has been completed. EPG and Texaco are engaged in negotiations over the appropriate allocation of the remediation costs.

6 — In August 1992, EPG received a notice from the current owner of a site in Etowah, Tennessee requesting compensation for remediation expenses associated with the site. These costs are estimated to be approximately $1.7 million. EPG and the other PRP are engaged in negotiations over the appropriate allocation of the alleged costs.

7 — EPG and other PRPs entered into an agreement to conduct a RI/FS for a site located in Fountain Inn, South Carolina. The RI/FS was completed in October 1994, and EPA issued a Record of Decision for the site in November 1994. The proposed remediation and EPA oversight costs are estimated to be $800,000. The allocation of these costs between EPG and the other PRPs is currently

being negotiated. EPG's share of the costs is estimated to be between $300,000 and $500,000 over a 5 year period.

8 — EPG has entered into a *de minimis* administrative order on consent with EPA for EPG's share of the environmental remediation costs associated with a site in Odessa, Texas. In accordance with the order, EPG paid total costs of approximately $32,000 in the fourth quarter of 1994.

Management believes the amount reserved as of December 31, 1994 is sufficient to cover these and other small environmental assessments and remediation activities.

The State of Tennessee has asserted a claim that EPG is a liable party under state environmental laws for cleanup costs associated with a site in Elizabethton, Tennessee. The State and EPA are in the preliminary stages of investigating the nature and extent of contamination, as well as identifying other PRPs. Since testing is in the initial stages, EPG is unable to estimate its potential share of any remediation costs.

EPG also has potential expenditures, of a capital nature, for the following environmental projects:

1 — EPG has analyzed CAAA, and believes that these rules will impact the Company's operations primarily in the following areas: (i) potential required reductions in the emissions of NOx in non-attainment areas; (ii) the requirement for air emissions permitting of existing facilities; and (iii) enhanced monitoring of air emissions. EPG anticipates capitalizing the equipment costs associated with complying with CAAA and estimates that approximately $30 million will be spent from 1995 through 2005. However, EPA's proposed enhanced monitoring rules, when finalized, could potentially impose greater costs to the Company.

2 — EPG has been conducting remediation of mercury contamination at certain facilities and is replacing mercury containing meters with other measurement devices. The mercury remediation project is expected to be completed in 1995 at a cost of approximately $8 million. EPG will close and retire about 1,500 earthen siphon/dehydration pits in the San Juan Basin as required by certain environmental regulations. The project is expected to be completed in 1995 at a cost of approximately $6 million. The mercury remediation and pit closure costs, which are associated with the retirement of equipment, will be recorded as adjustments to accumulated depreciation, as permitted by regulatory accounting.

It is possible that new information or future developments could require the Company to reassess its potential exposure related to environmental matters. As such information or developments occur, related accrual amounts will be adjusted accordingly.

5. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is presented in accordance with the requirements of SFAS No. 107. The estimated fair value amounts have been determined by the Company using available market information and valuation methodologies.

As of December 31, 1994, and 1993, the carrying amounts of certain financial instruments employed by the Company, including cash, cash equivalents, short-term borrowings and investments, and trade receivables and payables are representative of fair value because of the short-term maturity of these instruments. The fair value of the long-term debt has been estimated based on quoted market prices for the same or similar issues. The fair value of the project financing is representative of the carrying amount due to the short-term nature of the interest rates. The fair value of all derivative financial instruments is the amount at which they could be settled, based on quoted market prices or estimates obtained from dealers. The following table reflects the carrying amount and estimated fair value of the Company's financial instruments.

	December 31,			
	1994		1993	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Balance sheet financial instruments				
Long-term debt	$637,337	$621,400	$637,208	$696,200
Project financing	148,584	148,584	164,759	164,759
Other financial instruments				
Interest rate swap agreements	—	2,144	—	19,264
Price rate swap agreements	—	1,190	—	1,004
Futures contracts	—	84	—	—
Total	$785,921	$773,402	$801,967	$881,227

Derivative Financial Instruments

The Company has only limited involvement with derivative financial instruments and does not use them for trading purposes. The Company uses derivatives to manage well-defined interest rate and commodity price risks. Those financial instruments held for hedging purposes are used to hedge only firm commitments. In 1993, both EPG and EPGM entered into separate price swap agreements; however, all contracts held by EPG were settled by the end of 1993. There were no futures or option contracts held in 1993. With the exception of MPC's interest rate swap agreements, all derivative financial instrument contracts at December 31, 1994, are held by EPGM.

1. Interest Rate Swap Agreements

MPC has entered into interest rate swap agreements which effectively converted $114.3 million of floating-rate debt to fixed-rate debt. MPC makes payments to counterparties at fixed rates and in return receives payments at floating rates. At December 31, 1994, and 1993, MPC had two interest rate swap agreements outstanding with an aggregate notional amount of $114.3 million. The two swap agreements were entered into in March 1992 and have remaining terms of approximately 5 years and 7 years, respectively.

The primary risks associated with swaps are the exposure to movements in interest rates and the ability of the counterparties to meet the terms of the contracts. Based on review and assessment of counterparty risk, MPC does not anticipate non-performance by the other party.

2. Price Swap Agreements

In 1994 and 1993, EPG and EPGM entered into certain price swap agreements with counterparties to effectively manage a portion of the market risk associated with the fluctuations in the price of natural gas. The agreements include both (i) transactions in which one party agrees to pay a fixed price while the other party agrees to pay a price based on a published index, and (ii) transactions in which the parties agree to pay based on different indices. At December 31, 1994, and 1993, EPGM had swap agreements used on the buying side of natural gas transactions with notional contract amounts of approximately $22.3 million and $22.5 million, respectively. EPGM had swap agreements used on the selling side of natural gas transactions with notional contract amounts of approximately $6.3 million and $7.5 million, at December 31, 1994, and 1993, respectively. EPGM also held two swap agreements in which payment by both parties is based on different indices. These agreements had a notional contract amount of approximately $0.7 million at December 31, 1994. The price swap agreements entered into in 1994 extend for periods of up to 5 years, while those originating in 1993 have current terms of up to 4 years. During 1994, EPGM realized a pretax loss of approximately $1.4 million pertaining to price swap agreements. During 1993, EPG and EPGM, collectively, realized a pretax loss of approximately $0.2 million pertaining to price swap agreements.

The primary risks associated with swaps are the exposure to movements in the value of natural gas and the ability of the counterparties to meet the terms of the contracts. While the notional contract amounts reflect the extent of involvement in the price swap agreements, the amounts potentially subject to credit risk, in the event of non-performance by the other parties, are substantially smaller. EPG periodically reviews and assesses counterparty risk to limit any material impact to its financial position or results of operations; consequently, EPGM does not anticipate non-performance by the other parties.

3. Futures Contracts

In 1994, EPGM entered into futures contracts to effectively manage a portion of the market risk associated with fluctuations in the price of natural gas. At December 31, 1994, EPGM held in its portfolio 25 futures contracts for an aggregate notional value of $0.5 million, expiring in March 1995. During 1994, EPGM realized a pretax loss of approximately $0.5 million pertaining to futures contracts. At December 31, 1994, EPGM had an unrealized loss of approximately $1.2 million pertaining to such contracts which is reflected in the Consolidated Balance Sheet. Risks on futures contracts stem from market movements in the value of natural gas.

4. Option Contracts

Options give EPGM the right, but not the obligation, to buy or sell natural gas at a predetermined price during a specified period. EPGM purchased option contracts during 1994; however, at December 31, 1994, did not hold any in its portfolio. Risks on option contracts stem from movements in the value of natural gas.

Risk Management

The Company does not obtain collateral or other security to support financial instruments subject to credit risk, but monitors the credit standing of counterparties. MPC's objective in entering into the interest rate swap agreements was to avoid the interest rate risk associated with the floating rate debt. EPGM is engaged in the trading of natural gas in the spot (30 day), intermediate (up to 1 year), and long-term (in excess of 1 year) markets. Volatility of prices for natural gas has inherently created financial risk in conducting seasonal and long-term marketing. The primary reason EPGM's risk management program includes the use of these instruments is to guard against adverse changes in the price of natural gas and attempt to ensure a margin on purchases or sales of natural gas. EPGM has established policies and procedures governing the use of derivative financial instruments in over-the-counter and listed exchange-based markets to manage the risks of buying and selling natural gas.

A designated committee oversees risk management activities of EPGM to ensure that specific risk management strategies have been developed, reviewed, and implemented, which comply with the stated objectives approved by management.

6. ACQUISITION

On June 1, 1993, the Company acquired from a wholly owned subsidiary of Enron Corp., that subsidiary's 50 percent interest in MPC for approximately $40 million in cash, representing the approximate book value of the investment. The acquisition, which was funded by internally generated cash flow, gave the Company 100 percent ownership of MPC. The acquisition was accounted for using the purchase method.

In conjunction with the acquisition, the following liabilities were assumed:

	(In thousands)
Fair value of assets acquired	$145,643
Cash paid	39,396
Liabilities assumed	$106,247

The operating results of MPC are included in the Company's consolidated results of operations for 1994 and May 1993 through December 1993. The Company's previously owned 50 percent equity interest in MPC is included in other-net in the Consolidated Statement of Income.

The following pro forma summary presents the consolidated results of operations of the Company as if the acquisition had occurred as of January 1, 1993 or January 1, 1992. These pro forma results have been prepared for comparative purposes only and do not purport to be indicative of what may have resulted had the acquisition occurred as of those dates or of results which may occur in the future.

	Year Ended December 31,	
	1993	1992
	(In thousands, except per share amounts)	
Operating revenue	$922,593	$834,181
Net income	93,102	78,603
Earnings per common share	2.50	2.18

7. CORPORATE REORGANIZATION

During 1992, EPG completed several transactions in preparation for its separation from BR. In January and February 1992, EPG declared and paid dividends totaling $274 million to BR. These dividends were paid from the balance owed to EPG under an intercorporate cash management arrangement.

In March 1992, EPG completed the Offering. The proceeds from the Offering, net of related costs, totaled approximately $96 million. In June 1992, BR distributed its 31.4 million shares of EPG's common stock, which represented approximately 85 percent of EPG's outstanding common stock, to BR shareholders. As a result, BR no longer retains an ownership interest in EPG.

8. CAPITAL STOCK

Under EPG's employee stock option plans, options may be granted to officers and key employees at fair market value on the date of grant, exercisable in whole or part by the optionee after completion of one to three years of continuous employment from the grant date. Options are also granted to non-employee members of the Board at fair market value on the date of grant and are exercisable immediately. Under the terms of these plans, EPG may grant stock appreciation rights ("SARs") to certain holders of stock options. SARs are subject to the same terms and conditions as the related stock options. The stock option holder who has been granted tandem SARs can elect to exercise either an option or a SAR. SARs entitle an option holder to receive a payment equal to the difference between the option price and the fair market value of the common stock of EPG at the date of exercise of the SAR. To the extent a SAR is exercised, the related option is cancelled, and to the extent an option is exercised, the related SAR is cancelled.

In January 1992, the Board granted options exercisable for 722,300 shares of common stock effective upon the closing of the Offering. One-third of the options became exercisable on December 19, 1992; one-third became exercisable on January 15, 1994; and one-third became exercisable on January 15, 1995.

After the Offering, 597,838 BR stock options and 100,730 BR SARs, at prices ranging from $25.50 to $44.75 per share, were converted to EPG stock options and SARs at prices ranging from $13.51 to $22.91 per share.

Additionally, the Board granted the following stock options:

Grant Date	Number of Stock Options	Exercise Price Per Share	Exercisable Date
1/12/93	554,000	$30.81	1/12/94
3/18/93	3,000	36.19	3/18/93
5/1/93	3,000	38.19	5/1/93
7/22/93	15,000	37.25	1/22/94
1/14/94	655,100	36.88	1/14/95
1/14/94	3,000	36.88	1/14/94
3/17/94	5,000	39.56	3/17/94
1/13/95	633,000	29.94	1/13/96

Activity in EPG's stock option plans for 1992, 1993, and 1994 was as follows:

	Options	SARs	Exercise Price Per Share
Balance, June 30, 1992	1,705,498	631,702	$13.51 to $21.81
Converted	13,821	—	20.82 to 22.91
Granted	3,000	—	25.69
Exercised	628,258	441,499	13.51 to 19.00
Cancelled	30,800	85,000	13.51 to 19.00
Balance, December 31, 1992	1,063,261	105,203	$13.51 to $25.69
Granted	575,000	—	30.81 to 38.19
Exercised	247,143	35,049	13.51 to 22.91
Cancelled	41,382	—	19.00 to 30.81
Balance, December 31, 1993	1,349,736	70,154	$13.51 to $38.19
Granted	663,100	—	36.88 to 39.56
Exercised	50,162	22,000	13.51 to 30.81
Cancelled	29,983	—	19.00 to 36.88
Balance, December 31, 1994	1,932,691	48,154	$18.14 to $39.56

At December 31, 1994, 1,062,871 stock options and 48,154 SARs were exercisable at prices ranging from $18.14 to $39.56 per share.

Stock options shown as cancelled in the table above may be a result of the tandem SAR being exercised. SARs shown as cancelled in the table above were cancelled when the underlying stock options were exercised.

The maximum number of shares for which stock options may be granted under EPG's current stock option plans is approximately 7 million shares of common stock, to be issued from shares held in EPG's treasury or out of authorized but unissued shares of EPG's common stock, or partly out of each, as shall be determined by the Board.

In October 1992, the Board authorized the repurchase of up to 2 million shares of EPG's outstanding shares of common stock from time to time in the open market. Shares repurchased are held in EPG's treasury and are expected to be used in connection with EPG employee stock option plans to minimize dilution to existing shareholders. During 1992, EPG acquired 812,773 shares of its common stock for an aggregate value of $24 million and reissued, in connection with EPG's employee stock option plans, 628,258 shares of common stock out of treasury stock for an aggregate value of $11 million. The 184,515 remaining shares were reissued through April 1993, in connection with employee stock option plans, for an aggregate value of $5 million.

During 1993, EPG acquired 509,095 shares of its common stock for an aggregate value of $18 million and subsequently reissued, in connection with employee stock option plans, 22,734 shares of its common stock out of treasury stock for an aggregate value of $0.5 million. As of December 31, 1993, EPG had 486,361 shares of treasury stock. In addition, from April 1993 through December 1993, EPG issued 43,394 shares of common stock in connection with EPG's employee stock option plans.

In November 1994, the Board authorized the repurchase of an additional 3.5 million shares of EPG's outstanding common stock from time to time in the open market. Shares repurchased are held in EPG's treasury and are expected to be used in connection with EPG employee stock option plans and for other corporate purposes. During 1994, EPG acquired 1,362,937 shares of its common stock for an aggregate value of $44 million and subsequently reissued, in connection with employee stock option plans, 50,162 shares of its common stock out of treasury stock for an aggregate value of $1.8 million. In addition, 430,000 shares of treasury stock have been used to secure benefits under certain of the Company's benefit plans. These shares are subject to certain restrictions. As of December 31, 1994, EPG had 1,799,136 shares of treasury stock.

A total of 800, 2,300, and 132,700 restricted shares of EPG's common stock were granted to certain employees during 1994, 1993, and 1992, respectively. The market value of such shares awarded was approximately $26,000, $76,000, and $2.8 million in 1994, 1993, and 1992, respectively.

EPG has 25,000,000 shares of authorized preferred stock, par value $0.01 per share, none of which have been issued.

EPG filed a shelf registration statement in August 1994 pursuant to which EPG may offer up to $400 million of unsecured debt securities, preferred stock, and common stock from time to time as determined by market conditions. As of December 31, 1994, there had been no securities issued under this registration statement.

9. PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consists of the following:

	December 31,	
	1994	1993
	(In thousands)	
Property, plant, and equipment, at cost	$2,979,368	$2,873,301
Less accumulated depreciation	1,212,477	1,212,233
	1,766,891	1,661,068
Additional acquisition cost assigned to utility plant, net of accumulated amortization	99,006	104,418
Total property, plant, and equipment, net	$1,865,897	$1,765,486

10. INCOME TAXES

The following table reflects the components of income tax expense.

	Year Ended December 31, 1994	1993	1992
		(In thousands)	
Current			
Federal	$ 14,678	$ 42,112	$ 84,315
State	(5,609)	8,491	17,116
	9,069	50,603	101,431
Deferred			
Federal	35,062	7,506	(42,590)
Change in enacted tax rate	—	503	—
State	14,332	541	(11,878)
	49,394	8,550	(54,468)
Total tax expense	$ 58,463	$ 59,153	$ 46,963

The following table reflects the components of deferred tax expense (benefit).

	Year Ended December 31, 1994	1993	1992
		(In thousands)	
Gas cost settlements and recovery	$ 3,904	$ 17,633	$(51,602)
Financial accruals and reserves	28,176	(13,001)	(8,481)
Depreciation and amortization	33,363	7,355	10,567
Alternative minimum tax	(15,134)	2,103	(2,103)
Change in enacted tax rate	—	503	—
Other	(915)	(6,043)	(2,849)
Total deferred tax expense (benefit)	$ 49,394	$ 8,550	$(54,468)

The following table reflects the components of the net deferred tax liability.

	December 31, 1994	1993
	(In thousands)	
Deferred tax liabilities		
Property, plant and equipment	$275,214	$253,639
Regulatory and other assets	62,168	71,896
Total deferred tax liability	337,382	325,535
Deferred tax assets		
Take-or-pay buy-outs, buy-downs and prepayments	2,509	2,186
Accrual for regulatory issues	—	22,119
Other liabilities	55,740	40,842
Other	15,472	6,449
Total deferred tax asset	73,721	71,596
Net deferred tax liability	$263,661	$253,939

Tax expense of the Company differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference are as follows:

	Year Ended December 31,		
	1994	1993	1992
		(In thousands)	
Tax expense at the statutory federal rate of 35% for 1994 and 1993 and 34% for 1992	$51,827	$52,789	$41,918
Increase (decrease)			
State income tax, net of federal income tax benefit	5,670	5,871	3,458
Change in enacted tax rate	—	503	—
Other	966	(10)	1,587
Income tax expense	$58,463	$59,153	$46,963
Effective tax rate	39%	39%	38%

Deferred credits, in the Consolidated Balance Sheet, include excess deferrals resulting from the reduction of the statutory federal tax rate from 46 to 34 percent on July 1, 1987. Regulatory assets in the Consolidated Balance Sheet include expected future recoveries resulting from the increase of the statutory federal rate from 34 to 35 percent on January 1, 1993. Management expects to seek recovery of such amounts through its rates.

11. PENSION PLANS

Prior to July 1992, the Company participated in BR's pension plans, which were non-contributory defined benefit plans covering substantially all employees. The benefits were based on the number of years of credited service and the highest five-year average compensation levels. Contributions to the plans were determined by BR and were limited to amounts that were deductible for tax purposes.

In 1992, the Company established its own pension plans with provisions similar to those of the BR plans. On July 1, 1992, the Company's qualified pension plan received from BR's plan assets equal to the accumulated benefit obligation relating to the Company's employees.

The following table sets forth the qualified pension plan's funded status and amounts recognized in the Company's Consolidated Balance Sheet.

	December 31,	
	1994	1993
	(In thousands)	
Actuarial present value of benefit obligations		
Vested benefits	$430,499	$471,600
Nonvested benefits	818	896
Accumulated benefit obligation	$431,317	$472,496
Projected benefit obligation for service rendered to date	$489,121	$546,180
Plan assets at fair value, primarily listed stocks and U.S. bonds	407,620	434,505
Projected benefit obligation in excess of plan assets	$ 81,501	$111,675
Unrecognized net loss	$ 36,686	$ 64,194
Unrecognized net transition obligation	19,305	22,008
Recognized pension liability	25,510	37,991
Minimum liability adjustment included in recognized pension liability	—	(12,518)
	$ 81,501	$111,675

The following table reflects the components of net periodic pension cost.

	Year Ended December 31, 1994	1993	1992
	(In thousands)		
Service cost — benefits earned during the period	$ 9,345	$ 7,568	$ 3,311
Interest cost on projected benefit obligation	39,458	38,786	19,364
Actual return on plan assets	4,721	(43,850)	(27,641)
Pension cost allocated from BR plan	—	—	4,922
Net amortization and deferral	(39,669)	10,724	11,328
Net periodic pension cost	$ 13,855	$ 13,228	$ 11,284

The following table reflects the actuarial assumptions used in the valuation of the projected benefit obligation.

	1994	1993
Weighted average discount rate	8.75%	7.50%
Rate of increase in future compensation levels	5.00%	5.00%
Weighted average expected long-term rate of return on plan assets	9.25%	9.00%

Contributions to the plans are limited to amounts currently deductible for tax purposes. The accumulated vested benefit obligation is the actuarial present value of the vested benefits to which the employee is currently entitled, but it is based on the employee's expected date of termination.

12. POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS OTHER THAN PENSIONS

The Financial Accounting Standards Board issued SFAS No. 106 which requires companies to account for OPEBs, (principally retiree medical costs) on an accrual basis versus the pay-as-you-go basis traditionally followed by most United States companies. The Company adopted SFAS No. 106 effective January 1, 1993.

The Company provides a non-contributory defined benefit postretirement medical plan that covers employees who retired on or before March 1, 1986, and limited postretirement life insurance for employees who retire after January 1, 1985. As such, the Company's obligation to accrue for OPEBs is primarily limited to the fixed population of retirees who retired on or before March 1, 1986. The medical plan is funded to the extent employer contributions are recoverable through rates.

EPG began recovering through its rates the OPEB costs included in the settlement agreement. To the extent actual OPEB costs differ from the amounts funded, a regulatory asset or liability is recorded. Management expects to seek inclusion of such amounts in its rates.

The following table sets forth the postretirement plan's funded status and amounts recognized in the Company's Consolidated Balance Sheet.

	December 31, 1994	1993
	(In thousands)	
Accumulated postretirement benefit obligation	$ 86,656	$124,914
Plan assets at fair value, primarily U.S. stocks and U.S. bonds	16,758	8,751
Accumulated postretirement benefit obligation in excess of plan assets	$ 69,898	$116,163
Unrecognized net (gain) loss	$(26,441)	$ 9,285
Unrecognized transition obligation	96,987	105,796
(Prepaid) accrued postretirement benefit costs	(648)	1,082
	$ 69,898	$116,163

The following table reflects the components of net periodic postretirement benefit cost.

	Year Ended December 31, 1994	1993
	(In thousands)	
Interest cost on accumulated postretirement benefit obligation	$ 6,983	$ 9,377
Actual return on plan assets	472	(254)
Net amortization and deferral	6,585	9,062
Net periodic postretirement benefit cost	$ 14,040	$ 18,185

A 10 percent annual rate of increase in the per capita costs of covered health care benefits was assumed for 1995, gradually decreasing to 6 percent by the year 1999. Increasing the assumed health care cost trend rates by one percentage point in each year would increase the accumulated postretirement benefit obligation as of December 31, 1994, by approximately $8.0 million and increase the interest cost components of net periodic postretirement benefit cost for 1994 by approximately $0.7 million. A discount rate of 8.75 percent and 7.5 percent was used to determine the accumulated postretirement benefit obligation at December 31, 1994, and 1993, respectively. The weighted average of expected long-term rate of return for 1994 was 7.7 percent.

The Financial Accounting Standards Board issued SFAS No. 112 which requires companies to account for benefits to former or inactive employees after employment but before retirement (referred to in SFAS No. 112 as "postemployment benefits"). SFAS No. 112 is effective for the fiscal years beginning after December 15, 1993. These postemployment benefits include every form of benefit provided to former or inactive employees, their beneficiaries and covered dependents. Benefits include, but are not limited to, salary continuation, supplemental unemployment benefits, severance benefits, disability-related benefits (including workers' compensation), job training and counseling, and continuation of benefits such as health care benefits and life insurance coverage. Effective January 1, 1994, the Company adopted SFAS No. 112. The Company has recorded a liability for postemployment benefit costs of approximately $8 million to reflect the initial adoption of SFAS No. 112. Management expects to seek recovery of the $8 million through rates and has recorded a regulatory asset equal to that amount.

13. COMMITMENTS AND CONTINGENT LIABILITIES

See Note 2 and 4 of Notes to Consolidated Financial Statements, Items 1 and 2 — Business and Properties, El Paso Natural Gas Company, *Master Separation Agreement,* and Item 3 — Legal Proceedings for discussions of litigation and other contingencies.

Minimum annual rental commitments at December 31, 1994, are as follows:

Year Ending December 31,	Operating Leases
	(In thousands)
1995	$ 9,167
1996	9,576
1997	10,010
1998	10,465
1999	10,943
Thereafter	94,154
Total	$144,315

Rental expense for operating leases was $9 million in 1994 and $8 million in 1993 and 1992.

EPG has a lease agreement for approximately 391,207 square feet of space which is currently used as the Company headquarters and its gas control center. The lease expires in May 2007, and grants EPG two ten year options to extend the term of the lease.

At December 31, 1994, EPG had a commitment to purchase approximately $9 million of pipe in connection with the expansion of its existing mainline system in the San Juan Basin.

The Company, through a subsidiary, plans to enter into a 7.75 year lease. The lease will be an unconditional "triple net" lease with the trustee of a special purpose trust. The trust will obtain financing for construction of the plant from a consortium of financial institutions. The total amount financed via the operating lease will not exceed $80 million, and the annual lease obligation will be a function of the amount financed and a variable interest rate. The Company will have an option at the end of the lease term, and will have an obligation upon the occurrence of certain events, to purchase the plant for a price sufficient to pay the entire amount financed and accrued interest. If the Company does not purchase the plant at the end of the lease term, it will have an obligation to pay a residual guaranty amount equal to approximately 87 percent of the amount financed. Construction of the plant is expected to be completed in early 1996.

Management is not aware of other commitments or contingent liabilities which would have a materially adverse effect on the Company's financial condition or results of operations.

14. SIGNIFICANT CUSTOMERS

The Company had gross revenues equal to or in excess of 10 percent of consolidated operating revenues from the following customers:

	Year Ended December 31,		
	1994	1993	1992
		(In thousands)	
Southern California Gas Company	$190,989	$238,885	$249,277
Pacific Gas & Electric Company	154,674	168,246	137,968
Southwest Gas Corporation	— (a)	95,188	79,784

(a) Less than 10 percent of consolidated operating revenues.

15. SUPPLEMENTAL CASH FLOW INFORMATION

The following provides additional information concerning supplemental disclosures of cash flow activities:

	Year Ended December 31,		
	1994	1993	1992
		(In thousands)	
Interest	$ 70,906	$ 66,773	$ 47,047
Income taxes, net of refunds	31,231	38,993	140,766

16. RELATED PARTY TRANSACTIONS

For the first six months of 1992, BR and Meridian were considered related parties of EPG. Through February 1992, EPG participated in an intercorporate cash management arrangement with BR, pursuant to which excess cash balances from each of BR's operating subsidiaries were advanced to BR on a daily basis and cash requirements of BR's operating subsidiaries were funded daily through advances from BR. Balances under the arrangement accrued interest at rates approximating short-term market rates. In January and February 1992, EPG declared and paid dividends totaling $274 million to BR from the balance owed to EPG under the intercorporate cash management arrangement.

In April 1992, the Board declared a quarterly dividend on common stock of $0.25 per share to the June 1, 1992, stockholders of record. EPG paid the dividend on June 19, 1992, in the amount of $9.3 million, $8 million of which was paid to BR.

Revenues associated with the transportation of gas for Meridian by EPG were $15 million for the six months ended June 30, 1992.

Certain BR corporate overhead expenses were allocated to EPG for the first six months of 1992. The allocated amounts were not material and management believes the allocation methodology was appropriate.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders
El Paso Natural Gas Company

We have audited the consolidated financial statements and the financial statement schedules of El Paso Natural Gas Company listed in Item 14(a) of this Form 10-K. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of El Paso Natural Gas Company as of December 31, 1994 and 1993, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 1994, in conformity with generally accepted accounting principles. In addition, in our opinion, the financial statement schedules referred to above, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information required to be included therein.

COOPERS & LYBRAND L.L.P.

El Paso, Texas
January 20, 1995

EL PASO NATURAL GAS COMPANY

CONSOLIDATED QUARTERLY INFORMATION

Years Ended December 31, 1994 and 1993
(In thousands, except per share amounts)
(Unaudited)

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
1994				
Operating revenues	$227,698	$209,424	$210,805	$221,945
Operating income	$ 58,881	$ 56,019	$ 59,598	$ 47,797
Net income	$ 23,391	$ 21,096	$ 24,011	$ 21,115
Earnings per common share	$ 0.65	$ 0.58	$ 0.65	$ 0.57
1993				
Operating revenues	$232,349	$245,056	$220,611	$210,912
Operating income	$ 53,177	$ 55,487	$ 57,397	$ 63,184
Net income	$ 21,785	$ 18,365	$ 20,683	$ 30,840
Earnings per common share	$ 0.59	$ 0.49	$ 0.55	$ 0.83

SCHEDULE II

EL PASO NATURAL GAS COMPANY

VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 1994, 1993, and 1992
(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
1994					
Allowance for bad debts	$ 3,868	$ 2,029	$ 734	$ 476	$ 6,155
Allowance for gas imbalances	5,597	—	3,243	—	8,840
Allowance for take-or-pay receivables	19,387	—	—	10,061	9,326
1993					
Allowance for bad debts	$ 5,084	$ —	$ 145	$ 1,361(b)	$ 3,868
Allowance for gas imbalances	12,097	—	—	6,500(c)	5,597
Allowance for take-or-pay receivables	—	19,387	—	—	19,387
1992(a)					
Allowance for bad debts	$ 8,229	$ —	$ 115	$ 3,260(b)	$ 5,084
Allowance for gas imbalances	2,082	10,015	—	—	12,097

(a) Presentation of prior years has been changed to conform to current year presentation.

(b) Primarily accounts charged off.

(c) Primarily accounts recovered.

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

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information appearing under the caption "Proposal No. 1 — Election of Directors" in the Company's proxy statement for the 1995 Annual Meeting of Stockholders (the "Proxy Statement") is incorporated herein by reference. Information regarding executive officers of the Company is presented in Items 1 and 2 of this Form 10-K under the caption "Executive Officers of the Registrant."

ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the caption "Executive Compensation" in the Proxy Statement is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information appearing under the caption "Security Ownership of a Certain Beneficial Owner and Management" in the Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

PART IV

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

(a) The following documents are filed as a part of this report:

1. Financial statements.

The following consolidated financial statements of the Company are included in Part II, Item 8 of this report:

(b) Reports on Form 8-K:

No reports on Form 8-K were filed by the Registrant during the quarter ended December 31, 1994.

EL PASO NATURAL GAS COMPANY

EXHIBIT LIST
December 31, 1994

3(i)	— Restated Certificate of Incorporation of EPG dated January 22, 1992, (Form 10-K, No. 1-2700, filed January 29, 1992); Certificate of Designation, Preferences and Rights of Series A Junior Participating Preferred Stock of EPG, dated July 7, 1992, (Form 10-K, No. 1-2700, filed February 3, 1993).
*3(ii)	— By-laws of EPG, as amended September 1, 1994.
4.B.1	— Indenture, dated as of March 1, 1987, between EPG and Citibank, N.A., Trustee, with respect to EPG's 8⅝% Debentures due 2012 (Form S-3, No. 33-34284, filed April 20, 1990); Supplemental Indenture, dated December 24, 1991, (Form 10-K, No. 1-2700, filed January 29, 1992).
4.B.2	— Indenture, dated as of August 1, 1987, between EPG and Citibank, N.A., Trustee, with respect to EPG's 9.45% Notes due 1999 (Form S-3, No. 33-34284, filed April 20, 1990); Supplemental Indenture, dated December 24, 1991, (Form 10-K, No. 1-2700, filed January 29, 1992).
4.B.3	— Indenture, dated as of January 1, 1992, between EPG and Citibank, N.A., Trustee, with respect to EPG's 6.90% Notes due 1997, 7¾% Notes due 2002 and 8⅝% Debentures due 2022 (Form 10-K, No. 1-2700, filed January 29, 1992).
4.C.	— Shareholder Rights Plan (Form 10-Q, No. 1-2700, filed November 12, 1992).
10.A	— Mojave Pipeline General Partnership Agreement by and among El Paso Mojave Pipeline Co., HNG Mojave, Inc., and Pacific Interstate Mojave Company, dated as of March 26, 1985, (Form 10-Q, No. 1-2700, filed May 15, 1985); Amendment No. 1 to General Partnership Agreement dated as of September 29, 1986, (Form 10-Q, No. 1-2700, filed May 13, 1988); Amendment No. 2 to General Partnership Agreement dated as of September 30, 1991, (Form 10-Q, No. 1-2700, filed November 14, 1991).
10.B	— Lease, dated May 27, 1982, between EPG and First Capital Kayser Center (Form 10-Q, No. 1-2700, filed November 14, 1991).
*10.C	— Transportation Service Agreement as Amended and Restated, effective November 1, 1993, between EPG and Pacific Gas and Electric Company.
*10.D	— Transportation Service Agreement as Amended and Restated effective July 16, 1993, between EPG and Southern California Gas Company.
10.E	— Transportation Service Agreement, dated August 9, 1991, and effective September 1, 1991, between EPG and Southwest Gas Corporation for service to Arizona; Transportation Service Agreement, dated August 9, 1991, and effective September 1, 1991, between EPG and Southwest Gas Corporation for service to Nevada (Form 10-Q, No. 1-2700, filed November 14, 1991); Amendatory Agreement and replacement of Exhibit B to Transportation Service Agreement dated August 9, 1991, and effective May 8, 1992, between EPG and Southwest Gas Corporation for service to Nevada. (Form 10-K, No. 1-2700, filed February 3, 1993).
*10.E.1	— Exhibit B to the Transportation Service Agreement dated August 9, 1991, and effective March 1, 1994, between EPG and Southwest Gas Corporation for service to Arizona.

10.F	— Credit Agreement among Mojave Pipeline Company and Deutsche Bank AG, New York Branch, and Swiss Bank Corporation, New York Branch, individually and as Agents, and the Banks named therein, dated as of September 30, 1991, and the following documents related thereto: Sponsor Performance Agreement among EPG and Deutsche Bank AG, New York Branch, as Collateral Agent and Deutsche Bank AG, New York Branch and Swiss Bank Corporation, New York Branch, as Agents, dated as of September 30, 1991; Partner Performance Agreement among El Paso Mojave Pipeline Co. and Deutsche Bank AG, New York Branch, as Collateral Agent and Deutsche Bank AG, New York Branch and Swiss Bank Corporation, New York Branch, as Agents, dated as of September 30, 1991; Pledge Agreement made by El Paso Mojave Pipeline Co. with and to Deutsche Bank AG, New York Branch (as Collateral Agent) for the Secured Creditors, dated as of September 30, 1991; \$90,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Deutsche Bank AG, New York Branch; \$90,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Swiss Bank Corporation, New York Branch (Form 10-Q, No. 1-2700, filed November 14, 1991); Syndication and replacement of Notes with a \$52,750,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Swiss Bank Corporation, New York Branch; a \$40,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Deutsche Bank AG, New York Branch; a \$30,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Banque Indosuez; a \$20,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to the Sumitomo Bank, Limited, Houston Agency; a \$20,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to the Bank of Nova Scotia; a \$17,250,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Credit Lyonnais Cayman Islands Branch (Form 10-K, No. 1-2700, filed January 29, 1992). First Amendment to Credit Agreement dated as effective December 23, 1992, among Mojave Pipeline Company and Deutsche Bank AG, New York Branch and Swiss Bank Corporation, New York Branch; Amendment to Sponsor and Partner Performance Agreements entered into effective as of December 23, 1992; Syndication and replacement of Note for \$52,750,000 payable to Swiss Bank Corporation, New York Branch and Note for \$17,250,000 payable to Credit Lyonnais Cayman Islands Branch with a \$40,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Swiss Bank Corporation, New York Branch; and a \$30,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Credit Lyonnais Cayman Islands Branch. Second Amendment to Credit Agreement dated as effective June 1, 1993, among Mojave Pipeline Company and Deutsche Bank AG, New York Branch and Swiss Bank Corporation, New York Branch; Amended and Restated Sponsor Performance Agreement dated as effective June 1, 1993, among El Paso Natural Gas Company and Deutsche Bank AG, New York Branch and Swiss Bank Corporation, New York Branch; Amendment and Ratification of Partner Documents dated as effective June 1, 1993, among EPNG Mojave, Inc. and El Paso Mojave Pipeline Co. and Deutsche Bank AG, New York Branch and Swiss Bank Corporation, New York Branch (Form 10-Q, No. 1-2700, filed August 16, 1993). Replacement of \$30,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Banque Indosuez with a \$30,000,000 Note dated September 30, 1991, executed by Mojave Pipeline Company and payable to Bank of Scotland. (Form 10-Q, No. 1-2700, filed May 13, 1994).
10.G	— Master Separation Agreement and documents related thereto dated January 15, 1992, by and among Burlington Resources Inc., EPG and Meridian Oil Holding Inc., including Exhibits (Form 10-K, No. 1-2700, filed January 29, 1992).

10.H	— Revolving Credit and Competitive Advance Facility Agreement dated as of August 10, 1994, between EPG, Chemical Bank and certain other banks (Form 10-Q, No. 1-2700, filed November 14, 1994).
10.I	— Omnibus Compensation Plan dated as of January 1, 1992, (Amendment No. 1 to Form S-2, No. 33-45369, filed February 27, 1992).
10.J	— Incentive Compensation Plan dated as of January 1, 1992, (Amendment No. 1 to Form S-2, No. 33-45369, filed February 27, 1992).
10.K	— Compensation Plan for Non-Employee Directors dated as of January 1, 1992, (Amendment No. 1 to Form S-2, No. 33-45369, filed February 27, 1992).
10.L	— Stock Option Plan for Non-Employee Directors dated as of January 1, 1992, (Amendment No. 1 to Form S-2, No. 33-45369, filed February 27, 1992).
10.M	— Rights Plan dated as of January 1, 1992, (Amendment No. 1 to Form S-2, No. 33-45369, filed February 27, 1992).
*10.N	— Supplemental Benefits Plan, Amended and Restated Effective as of January 13, 1995.
10.O	— Senior Executive Survivor Benefit Plan effective January 1, 1992, (Amendment No. 1 to Form S-2, No. 33-45369, filed February 27, 1992).
*10.P	— Deferred Compensation Plan, Amended and Restated Effective as of January 13, 1995.
*10.Q	— Retirement Income Plan for Non-Employee Directors, Amended and Restated Effective as of January 13, 1995.
*10.R	— Key Executive Severance Protection Plan, Amended and Restated Effective as of January 13, 1995.
*10.S	— Director Charitable Award Plan, Amended and Restated Effective as of January 13, 1995.
10.T	— Receivables Purchase and Sale Agreement dated as of January 14, 1992, between EPG, CIESCO L.P., Corporate Asset Funding Company, Inc. and Citicorp North America, Inc. (Form 10-K, No. 1-2700, filed February 3, 1993).
10.U	— Employment Agreement dated July 31, 1992, between The Company and William A. Wise (Form 10-K, No. 1-2700, filed February 3, 1993).
10.V	— Letter Agreement dated October 22, 1990, between The Company and Luino Dell'Osso, Jr. (Form 10-K, No. 1-2700, filed February 3, 1993).
10.W	— Letter Agreement dated February 22, 1991, between The Company and Britton White, Jr. (Form 10-K, No. 1-2700, filed February 3, 1993).
*10.X	— Letter Agreement dated January 13, 1995, between The Company and William A. Wise.
*11	— Computation of Earnings per Common Share.
*12	— Computation of Ratio of Earnings to Fixed Charges.
*21	— Subsidiaries of the Registrant.
*23	— Consents of Experts and Counsel.
*27	— Financial Data Schedule.

Each exhibit identified on this Exhibit List is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

SIGNATURES

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

EL PASO NATURAL GAS COMPANY
Registrant

By /s/ WILLIAM A. WISE
William A. Wise
Chairman of the Board,
President, and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of El Paso Natural Gas Company and in the capacities and on the date indicated:

Signature	Title	Date
/s/ WILLIAM A. WISE (William A. Wise)	Chairman of the Board, President, Chief Executive Officer, and Director	January 13, 1995
/s/ LUINO DELL'OSSO JR. (Luino Dell'Osso Jr.)	Vice Chairman of the Board, Chief Operating Officer, and Director	January 13, 1995
/s/ H. BRENT AUSTIN (H. Brent Austin)	Senior Vice President and Chief Financial Officer	January 13, 1995
/s/ THOMAS E. RICKS (Thomas E. Ricks)	Vice President, Chief Accounting Officer, and Controller	January 13, 1995
/s/ BYRON ALLUMBAUGH (Byron Allumbaugh)	Director	January 13, 1995
(Eugenio Garza Lagüera)	Director	January 13, 1995
/s/ JAMES F. GIBBONS (James F. Gibbons)	Director	January 12, 1995
/s/ BEN F. LOVE (Ben F. Love)	Director	January 13, 1995
/s/ KENNETH L. SMALLEY (Kenneth L. Smalley)	Director	January 13, 1995

REPORT OF MANAGEMENT

El Paso

To the Board of Directors and Stockholders
El Paso Natural Gas Company

The Management of El Paso Natural Gas Company is responsible for the preparation, integrity, and fairness of the accompanying financial statements as well as other information presented in this Annual Report on form 10-K. Such responsibility includes judgments, estimates, the selection of appropriate generally accepted accounting principles, the consistent application of such principles, and devising and maintaining adequate systems of internal controls.

In the opinion of management, the financial statements are fairly stated and have been prepared in conformity with generally accepted accounting principles, and, to that end, the Company and its subsidiaries maintain a system of internal control which: provides reasonable assurance that transactions are recorded properly for the preparation of financial statements; safeguards assets against unauthorized acquisition, use or disposition; maintains accountability for assets; requires proper authorization and accountability for all transactions; provides for a comparison of the recorded and existing assets at reasonable intervals and requires appropriate action with repsect to any difference; and promotes compliance with applicable laws and regulations. The financial statements have been audited by the independent accounting firm, Coopers & Lybrand L.L.P. , which was given unrestricted access to all financial records and related data. Their audit was conducted in accordance with generally accepted auditing standards and included a review of internal control to the extent deemed necessary for the purpose of their audit.

Management is responsible for the effectiveness of its system of internal control. This is accomplished through established codes of conduct, accounting and other control systems, policies and procedures, employee selection and training, appropriate delegation of authority, and segregation of responsibilities. To further ensure compliance with established standards and related control procedures, the Company conducts an ongoing, substantial corporate audit program. Corporate auditors monitor the operation of the internal control system and report findings and recommendations to management, including corrective action taken to address control deficiencies and opportunities for improving the system. Even an effective internal control system has inherent limitations, including the possibility of circumvention or overriding of controls, and therefore can provide only reasonable assurance with respect to financial statement preparation.

The Audit Committee of the Board of Directors, composed entirely of Directors who are not employees of El Paso Natural Gas Company, has met privately and separately with independent certified public accountants, corporate auditors, and management of the Company to review accounting, auditing, internal control, and financial reporting matters.

January 13, 1995

H. Brent Austin   Thomas E. Ricks

H. Brent Austin
Senior Vice President and
Chief Financial Officer

Thomas E. Ricks
Vice President and
Controller

DIRECTORS OF

EL PASO NATURAL

GAS COMPANY

Byron Allumbaugh (1) (2)
Chairman of the Board and
Chief Executive Officer
Ralphs Grocery Company

Luino Dell'Osso, Jr.
Vice Chairman of the Board
and Chief Operating Officer
El Paso Natural Gas Company

Eugenio Garza Lagüera (1) (2)
Chairman of the Board
Valores Industriales, S.A. ("VISA")
Fomento Económico
Mexicano, S.A. de C.V. ("FEMSA")
Grupo Financiero Bancomer, S.A. de C.V.
BANCOMER
Instituto Tecnologico Y de Estudios
Superiores de Monterrey, A.C.

James F. Gibbons Ph.D. (1) (2)
Dean of the School of Engineering
Stanford University

Ben F. Love (1) (2)
Investor
Retired Chairman of the Board and
Chief Executive Officer
Texas Commerce Bancshares, Inc.

Kenneth L. Smalley (1) (2)
Retired Senior Vice President
Phillips Petroleum Company and
Retired President
Phillips 66 Natural Gas Company

Malcolm Wallop (3)
President
Frontiers of Freedom Foundation
Former United States Senator (1976 - 1994)

William A. Wise
Chairman of the Board, President and
Chief Executive Officer
El Paso Natural Gas Company

(1) Audit Committee

(2) Compensation Committee

(3) Director as of February 1, 1995

El Paso

CORPORATE INFORMATION

Principal Corporate Office
El Paso Natural Gas Company
100 N. Stanton Street
El Paso, Texas 79901
(915) 541-2600

Stock Transfer Agent, Registrar,
Dividend Reinvestment Agent
and Continuous Oddlot
Sales Program Agent
The First National Bank of Boston
Shareholder Services
Mail Stop: 45-02-09
P.O. Box 644
Boston, Massachusetts 02102
(800) 736-3001
(617) 575-3100

Stock Exchange Listing
New York Stock Exchange
Symbol: EPG

Annual Meeting
The Annual Meeting of Stockholders
will be held in Phoenix, Arizona
on March 16, 1995.

Additional copies of this Annual Report
are available, without charge,
by writing or calling:

Investor and Public Relations
Norma F. Dunn
El Paso Natural Gas Company
P.O. Box 1492
El Paso, Texas 79978
(915) 541-5443

Corporate Secretary
Stacy J. James
El Paso Natural Gas Company
P.O. Box 1492
El Paso, Texas 79978
(915) 541-3403

El Paso

El Paso
Natural Gas Company

P.O. Box 1492
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915-541-2600