COLUMBIA GAS SYSTEM

C

1992
Annual
Report

Mission Statement

The Columbia Gas System, Inc., through its subsidiaries, is active in pursuing opportunities in all segments of the natural gas industry and in related energy resource development. Exemplified by Columbia's three-star logo, these separately managed companies strive to benefit: System shareholders—*through enhancing the value of their investment;* customers—*through efficient, safe, reliable service;* and employees—*through challenging and rewarding careers.*

Portraits of Accomplishment

Columbia Gas could not be a natural gas industry leader without the energy of dedicated, innovative employees. Columbia's 1992 annual report highlights four of Columbia's many talented employees. Their accomplishments exemplify the hard work and effort that help Columbia maintain its leadership role—in oil and gas drilling, in customer service and in environmentally sound energy technologies.

Pictured at the opening of the operating segment discussions are: Dick Stollar, chief geologist for Columbia Natural Resources Company; Janet Shobe, customer service representative, and Jim Ogg, meter mechanic, for Columbia Gas Transmission Corporation; and Tim Davis, manager of natural gas vehicle market development for the Columbia distribution companies.

No company can attain its goals without the sustained accomplishments of a dedicated workforce. This is one of Columbia's strengths.

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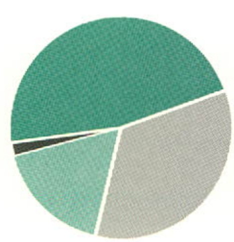
	1992*	1991*	1990
Income Statement Data ($ in millions)			
Operating Revenues	**2,922.0**	2,576.8	2,357.9
Net Income (Loss)	**51.2**	(694.4)	104.7
Operating Income (Loss) by Segment:			
Oil and Gas	**(101.2)**	(4.5)	43.3
Transmission	**129.9**	(1,192.2)	128.2
Distribution	**137.7**	114.9	96.7
Other Energy & Corporate	**(3.5)**	(4.6)	(6.1)
Total	**162.9**	(1,086.4)	262.1
Per Share Data ($)			
Net Income (Loss) on Common Stock	**1.01**	(13.74)	2.21
Dividends	**–**	1.16	2.20
Book Value	**21.26**	19.92	34.83
Market Price:			
High	**23⅞**	47 ½	54 ¾
Low	**14**	12 ⅞	41 ½
Close	**19⅛**	17 ¼	46 ⅞
Common Stock Data (000)			
Average Shares Outstanding	**50,559**	50,537	47,316
Average Daily Shares Traded	**141**	383	146
Operating Statistics			
Gas Production (billion cubic feet)	**69.2**	76.3	75.3
Oil Production (thousands of barrels)	**3,061**	3,411	2,688
Transmission Throughput (billion cubic feet)	**1,741.0**	1,527.2	1,386.1
Distribution Throughput (billion cubic feet)	**486.7**	462.4	465.7
Balance Sheet and Other Data ($ in millions)			
Capital Expenditures	**299.7**	381.9	629.6
Total Assets	**6,530.9**	6,332.2	6,196.3

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financial Statements.



NET PLANT BY SEGMENT AT DECEMBER 31, 1992
($ in millions)

Transmission	1,603
Distribution	1,175
Oil & Gas	591
Other Energy	61

To Our Shareholders

While the principal focus of your management and your board of directors continues to be the prompt resolution of the bankruptcy proceedings, day-to-day operations of Columbia's business units are certainly not being ignored. In fact, I'm pleased to report that they are all functioning efficiently and effectively.

Columbia Gas Chairman and CEO John H. Croom inspects TriStar Ventures' Pedricktown, New Jersey, cogeneration plant. The facility began supplying electric power to New Jersey residents and steam to a major chemical facility in mid-1992. Nearby in Vineland, New Jersey, a TriStar partnership is constructing a similar installation at a food-processing plant.

Unlike many companies that seek protection under Chapter 11 of the Bankruptcy Code, Columbia is not losing money. Net income for 1992 was $51.2 million, or $1.01 a share. However, if we eliminate the effects of the special charges and bankruptcy-related costs that have tended to obscure the stability and strength of our operating subsidiaries, we get a clearer picture of Columbia's operating performance. As shown on the accompanying chart, absent these charges and costs, net income for 1992 would have been $98.7 million as compared with $80.8 million in 1991. Much of the improvement in 1992's earnings is due to the combined effect of improved rate structures and substantial increases in throughput by both our transmission and distribution segments. The results also reflect increased revenues from our propane operations and income from two new cogeneration facilities that TriStar Ventures and its partners put into commercial operation in 1992. Although early in the year the earnings of our oil and gas segment (like those of other oil and gas production companies) were constrained by low energy prices, this situation improved in the fourth quarter due to higher gas prices and increased domestic oil production resulting from a highly successful horizontal drilling program in the Southwest.

Developing and implementing strategies and programs that will enable each of our business segments to operate profitably will continue to be a major priority as your management and your board of directors work closely together to emerge from Chapter 11 as promptly and effectively as possible.

Members of your board of directors continue to be actively involved in the bankruptcy proceedings, both individually and through the special committee that was formed to assist management in devising a responsible plan of reorganization. Their support and their input into the decision-making process have been extremely valuable.

As the 1992 performances of our various operating companies demonstrated, our businesses are fundamentally strong. This includes our principal pipeline subsidiary, Columbia Gas Transmission Corporation, now that it has rejected the noncompetitive gas purchase contracts that were the major cause of Columbia's financial difficulties.

The exaggerated claims for damages and lost profits resulting from Columbia Transmission's rejection of the noncompetitive contracts continue to be a principal issue in the bankruptcy proceedings. They are currently being reassessed by a claims resolution process established by the bankruptcy court that we believe will result in recalculated claims which are only a fraction of those presently asserted by the producers.

Over the past several months, additional issues have surfaced and competing interests, including regulatory agencies, have become involved, making the proceedings far more complex and time-consuming. These matters are addressed in another section of this report; however, the most significant involves complex litigation resulting from the attempt by Columbia Transmission's creditors' committee to access more than $2 billion of parent company assets. The committee's complaint challenges the validity of secured and unsecured debt Columbia Transmission owes the parent company, dividend and interest payments it made to the parent company and its transfer of natural resource properties to another subsidiary. We are confident that our strong and credible defenses will prevail on each of these issues and are seeking to expedite court proceedings that have been pending for several months.

Highlights
Year Ended December 31
($ in millions except per-share data)

	1992	1991
Net income before extraordinary item, accounting changes and unusual items	$ 98.7	$ 80.8
Extraordinary item and accounting changes	(39.7)	100.4
Unusual items	(7.8)	(875.6)
Net Income (Loss)	$ 51.2	$ (694.4)
Earnings (loss) per share		
Net income before extraordinary item, accounting changes and unusual items	$ 1.95	$ 1.60
Extraordinary item and accounting changes	(0.78)	1.98
Unusual items	(0.16)	(17.32)
Earnings (Loss) on Common Stock	$ 1.01	$ (13.74)

Delays Disrupt Timetable

Delays associated with these court cases and other issues have severely disrupted our projected timetable for emerging from Chapter 11. It now appears unlikely that we will be able to gain approval for plans of reorganization before the end of this year.

Let me assure you that your management and your board of directors are as eager as you are to conclude the bankruptcy proceedings. We continue to believe that it is in the overall best interests of all concerned to avoid prolonged and costly litigation by developing consensual reorganization plans that maximize value to existing shareholders, creditors and other affected parties. This has been our goal from the start, and we are working hard to accomplish it. We are optimistic that preliminary discussions of reorganization proposals currently under way with representatives of various constituencies will prove fruitful and lead to plans that have broad support. However, we also are confident of the strength of our legal positions and are prepared to continue court proceedings to preserve shareholder equity if that should become necessary.

Order 636

Looking ahead, Columbia is well-prepared for the changes taking place throughout the gas industry as a result of the radically new, industry-wide operating guidelines mandated in the Federal Energy Regulatory Commission's Order No. 636. Commonly referred to as the restructuring rule, Order 636 will result in unprecedented levels of competition throughout the gas industry. It will have a significant impact on the relationships between various segments of the industry and change the traditional roles of Columbia's operating units.

For example, responsibility for developing and managing gas supply will transfer from pipeline companies to distribution companies. Fortunately, Columbia's distribution companies already have in place one of the nation's most sophisticated supply procurement programs that will provide their customers with ample and dependable supplies of competitively priced natural gas in the years ahead.

Under the new guidelines, the sales function, traditionally provided by most pipeline companies, will all but disappear. Beginning later this year, under FERC-approved schedules, Columbia's pipeline companies plan to offer their distribution company and end-user customers a wide array of competitively priced transportation and storage services that will better match their needs under Order 636.

Recognizing the significant effect Order 636 and other regulatory and market forces are having on the gas industry, Columbia is taking a close look at the way its operations are structured. Special teams are examining various functions and processes and asking: "Is there a better way?" Our objective is to better position each of our business segments to effectively compete in the energy industry's rapidly changing environment.

Strong, Stable Markets

Columbia's markets remain strong. Customer demand has been stable throughout our operating territory during the past few years despite the prolonged recession and the demand-depressing effect of warm weather.

Longer term, the natural gas industry is full of promise. In the years ahead, the United States will need substantial quantities of clean energy. There is growing recognition that natural gas is the environmentally preferred fuel and that sufficient domestic reserves of clean-burning gas are available.

Columbia should benefit from the expanded role that natural gas will play in our nation's future. We are encouraged by the potential offered by new markets such as the growing use of natural gas to generate electric power and to fuel motor vehicles. The amount of gas our distribution companies expect to sell for electric power generation alone is expected to increase 10 percent annually over the next five years.

LNG Business Plan

Each of our operating companies continues to review and adjust its business plan to take advantage of all marketing opportunities. For example, our Columbia LNG subsidiary is actively seeking authorization to initiate a service at its liquefied natural gas receiving and regasification terminal on the Chesapeake Bay that will provide distribution companies with extra gas they need to serve the abnormally large demands of their customers on colder winter days.

Columbia LNG is also investigating opportunities that could result in the terminal once again being used to handle liquefied natural gas imports.

One major reason Columbia can look to the future with confidence is the efficiency and effectiveness of its various operating companies. The latest testimony to this was contained in the results of an outside audit of our largest distribution company, Columbia Gas of Ohio. For over 10 months an outside audit firm conducted a broad-based examination of the company's operations, policies and planning capabilities, which I might add are consistent with those of each of our other distribution subsidiaries. The auditors' findings were summed up in this excerpt from the final report: "Columbia Gas of Ohio is well-managed, understands and deals effectively with emerging issues and continued changes in the industry, and is positioned to remain a viable and effective local distribution company."

Another major reason Columbia is optimistic about the future is its skilled and dedicated workforce. The outstanding efforts of the 10,000-member Columbia family contributed greatly to the improved performances of our operating units this past year. Their consistent ability to deliver efficient, dependable, high-quality services has been a source of pride and gratification over the years. Without their help, our achievements would not have been possible. Their response to the challenges of these difficult times has been nothing short of outstanding. Each is committed to seeing that his or her company is recognized as the best in the industry.

Board Member Resigns

Effective December 31, 1992, John W. Snow, chairman, president and chief executive officer of CSX Corporation, resigned from the board of directors citing the press of CSX business and increased responsibilities in other areas. Columbia benefited greatly from his business knowledge during the time he served on the board. His advice and counsel will be missed.

In the coming year, your management, your board of directors and the entire Columbia team are committed to pursuing all opportunities that will provide the highest quality services to our customers and build value for our shareholders.

Sincerely,

JH Croom

John H. Croom
Chairman, President and CEO

February 17, 1993

SYSTEM PROFILE

The Columbia Gas System is one of the nation's largest natural gas systems. It consists of a holding company, a service company and 17 operating subsidiaries. The operating units are engaged in the exploration, production, purchase, marketing, storage, transmission, and wholesale and retail distribution of natural gas, as well as other energy operations such as cogeneration. Columbia's operations are divided into four primary segments—oil and gas, transmission, distribution, and other energy operations.

Oil and Gas Operations

Two Columbia subsidiaries, Columbia Gas Development Corporation and Columbia Natural Resources, Inc., explore for, develop, purchase, produce, and market oil and natural gas in the United States. These companies hold interests in more than two million net acres of natural gas and oil leases and have proved reserves in excess of 800 billion cubic feet of natural gas equivalent.

Operations are focused in the Appalachian, Arkoma, Michigan, Permian, Powder River and Williston basins; onshore and offshore in the Gulf Coast areas of Texas and Louisiana, and in Utah and California. Offshore holdings include interests in federal blocks, most of which are located in the West Cameron, Vermilion, Eugene Island and Ship Shoal areas of the Gulf of Mexico.

Columbia's exploration and development companies are among the industry's leaders in utilizing new technologies such as horizontal drilling and three-dimensional seismic analysis. Their success rates have been consistently better than national averages.

Transmission Operations

Columbia's two interstate pipeline companies, Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company, operate a 23,700-mile pipeline network that extends from offshore in the Gulf of Mexico to New York State and the Eastern Seaboard. In addition, Columbia Transmission operates one of the nation's largest underground storage systems.

OIL AND GAS

Net Acreage (000)		Net Productive Gas Wells	5,926
Developed	1,629	Net Productive Oil Wells	366
Undeveloped	880	Oil and Gas Production	
Proved Reserves		Natural Gas (Bcf)	69
Natural Gas (Bcf)	780	Oil (000 Bbls)	3,061
Oil (000 Bbls)	14,650	1992 Capital Expenditures ($ in millions)	71

TRANSMISSION

Total Throughput (Bcf)	1,741	Storage Capacity (Bcf)	775
Sales (Bcf)	196	1992 Capital Expenditures ($ in millions)	114
Transportation (Bcf)	1,545		

Historically, Columbia Transmission offered both a wholesale sales service and a transportation service to local distribution companies. However, when a new federally mandated business restructuring takes effect in late 1993, Columbia Transmission will expand its transportation and storage services for local distribution companies and their industrial and commercial customers and provide a minimal sales service. Columbia Gulf's pipeline system, which extends from offshore Louisiana to West Virginia, carries a major portion of the gas delivered by Columbia Transmission. It also transports gas for third parties within the production areas of the Gulf Coast. Columbia Gulf owns interests in the Overthrust, Ozark and Trailblazer pipelines, which extend into major midcontinent and western gas-producing areas. Combined, Columbia Transmission and Columbia Gulf serve customers in 15 northeastern, middle Atlantic, midwestern, and southern states and the District of Columbia.

Columbia LNG Corporation, the owner of the largest and most strategically located liquefied natural gas receiving and regasification terminal in North America, has announced plans to initiate peaking and terminalling services by the end of 1994.

Distribution

Retail Customers		Total Throughput (Bcf)	487
Residential	1,711,946	1992 Capital Expenditures ($ in millions)	100
Commercial	161,937		
Industrial and Other	2,382		
Total	1,876,265		

Other Energy

Coal Reserves (million tons)	550	Propane Customers	65,899
1992 Capital Expenditures ($ in millions)	15	Gallons Sold (000)	63,348

Distribution Operations

Columbia's five distribution subsidiaries provide natural gas service to more than 1.8 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky and Maryland. These subsidiaries not only develop gas supplies for their high-priority customers, but also transport gas for industrial and commercial customers who purchase gas from other sources. More than 28,000 miles of distribution pipelines serve such major markets as Columbus, Lorain, Parma, Springfield and Toledo in Ohio; Gettysburg, York and a part of Pittsburgh in Pennsylvania; Lynchburg, Staunton, Portsmouth and Richmond suburbs in Virginia; Ashland, Frankfort and Lexington in Kentucky; and Cumberland and Hagerstown in Maryland.

The distribution companies are leaders in developing new natural gas technologies, guiding research, organizing field tests and encouraging the manufacture and marketing of natural gas vehicles, gas air conditioning and heat pumps, efficient water and space heaters, and fuel cells.

Other Energy Operations

Columbia's TriStar Ventures Corporation primarily participates in natural gas-fueled cogeneration projects that produce both electricity and useful thermal energy. In 1992, projects developed and managed by TriStar and its partners began operating in New Jersey and New York and construction was begun on a second project in New Jersey. A fourth major TriStar cogeneration project is in the permitting stage in the District of Columbia.

Two System subsidiaries, Columbia Propane Corporation and Commonwealth Propane, Inc., sell propane at wholesale and retail to approximately 66,000 customers in six states.

In the Appalachian area, another System subsidiary owns approximately 550 million tons of coal reserves, much of which contain less than one percent sulfur. Approximately 50 percent of these reserves are leased to other companies for development.

The Columbia Gas System Service Corporation takes advantage of economies of scale to provide centralized, cost-efficient data processing, financial, accounting, legal and other services for the parent company and other operating subsidiaries.

Operating Results ($ millions)

Highlights

OIL AND GAS

	1992	1991	1990
Operating Revenues	**198.7**	214.8	215.0
Operating Expenses	**299.9**	219.3	171.7
Operating Income (Loss)	**(101.2)**	(4.5)	43.3
Capital Expenditures	**70.8**	120.8	229.0
Natural Gas Production (Bcf)	**69.2**	76.3	75.3
Oil Production (000 Bbls)	**3,061**	3,411	2,688

- Columbia's southwest exploration drilling efforts experienced a 42 percent success rate–more than double the normal industry rate.
- Aggressive marketing, long-term contracts and price hedging programs allowed Columbia to market its gas at an average price that was 25 percent higher than the average spot market price.
- Columbia's domestic oil production rose eight percent, while domestic gas production was virtually unchanged.

TRANSMISSION

	1992	1991	1990
Net Revenues	**761.4**	634.5	647.3
Operating Expenses	**631.5**	1,826.7	519.1
Operating Income (Loss)	**129.9**	(1,192.2)	128.2
Total Throughput (Bcf)	**1,741.0**	1,527.2	1,386.1
Capital Expenditures	**114.2**	152.9	279.5

- Columbia's transmission companies proposed a new menu of 18 services that respond to customer needs and comply with new federal guidelines.
- The transmission companies reached rate case settlements with their customers.
- Studies continued to assess the impact of new environmental requirements on past operating practices.
- Total throughput increased 14 percent.
- Columbia Transmission's service territory experienced its eighth consecutive warmer-than-normal heating season.
- An agreement to sell Columbia LNG stock was terminated.

DISTRIBUTION

	1992	1991	1990
Net Revenues	**696.5**	645.5	622.4
Operating Expenses	**558.8**	530.6	525.7
Operating Income	**137.7**	114.9	96.7
Total Throughput (Bcf)	**486.7**	462.4	465.7
Customers (millions)	**1.9**	1.8	1.9
Capital Expenditures	**99.7**	98.0	107.0

- Columbia's distribution companies helped promote the natural gas vehicle market, winning a national award for efforts to encourage production of natural gas-powered lift trucks and opening the nation's largest public natural gas vehicle fueling station in Columbus.
- Columbia Gas of Ohio became the latest Columbia distribution subsidiary to earn high marks after a third-party management audit.
- Despite the economic downturn and warm weather, Columbia's distribution companies increased throughput by 5 percent and added 28,000 customers.
- The distribution companies strengthened their supply planning efforts in response to new federal guidelines.

OTHER ENERGY

	1992	1991	1990
Net Revenues	**97.6**	102.1	101.2
Operating Expenses	**90.8**	97.2	95.7
Operating Income	**6.8**	4.9	5.5
Capital Expenditures	**15.0**	10.2	14.1

- Commercial service began at joint-venture cogeneration projects in New Jersey and New York, and ground was broken for a project at a food processing plant in New Jersey.
- Realigned customer mix and reduced delivery costs improved propane profit margins.

Trends Affecting Operations	Outlook
▪ Gas supply and demand are becoming more balanced. This should alleviate the downward pressure on gas prices caused by the gas supply deliverability surplus of the 1980s. ▪ While wellhead prices for oil and gas will remain volatile, a trend toward moderate price appreciation should bolster drilling economics. ▪ Strengthened by a favorable political climate and natural gas's beneficial environmental attributes, demand growth forecasts continue to be favorable. ▪ As major oil companies refocus their efforts overseas, domestic opportunities for independent producers are improving.	▪ Columbia's oil and gas companies are continuing to invest in the latest technologies to reduce the risks and costs associated with exploration and development efforts. ▪ Natural gas marketing is being strengthened to capitalize on opportunities created by recent federal regulations and capture business efficiencies.
▪ New federal regulations will permit customers to shop for the best portfolio of services and prices, thus increasing competition for both existing and new markets. ▪ Competition will require increased reliance on improved technologies. ▪ Changing environmental regulations will have a major impact on operations and construction projects. ▪ New federal regulations will provide greater opportunities for LNG peaking services.	▪ Anticipated regulatory stability during the next few years will allow Columbia's transmission companies to focus their attention on satisfying customer needs. ▪ The transmission companies will work with federal, state and local regulatory agencies and expand employee training programs to assure that their operations are as safe and environmentally benign as possible. ▪ Electronic measurement and other computer-based technologies that offer competitive advantages and operating efficiencies will continue to be aggressively pursued. ▪ Columbia LNG plans to reactivate the Cove Point terminal as a peaking facility and offer a terminalling service for imported LNG.
▪ State regulatory commissions will carefully monitor new federal guidelines requiring strong supply portfolio planning capabilities. ▪ Weather variations will continue to be the major factor in residential and commercial customer consumption levels. ▪ The Clean Air Act and the National Energy Strategy offer opportunities to build markets by promoting the beneficial environmental attributes and domestic availability of natural gas. ▪ Core markets will face aggressive competition from alternative fuels.	▪ To remain competitive with electric utilities, Columbia's distribution companies are emphasizing programs that focus on reducing costs and promoting conservation. ▪ The distribution companies are seeking "weather normalization clauses" in their rate structures to reduce the effects of weather variations on customer bills and on earnings and cash flow. ▪ Growing year-round and off-season markets, such as electric generation and gas air conditioning, that complement heat-sensitive residential and commercial customers, will help smooth distribution's load profile and improve financial performance. ▪ Through effective management, Columbia's distribution companies are minimizing the need for rate case filings.
▪ Federal regulations are increasing the complexity of securing long-term gas supply and transportation arrangements for cogeneration projects. ▪ Propane faces growing competition from other fuels.	▪ TriStar Ventures' fuel management capabilities will be a valuable attribute in securing independent power project opportunities. ▪ Propane marketing programs gear up to build year-round load and maintain market leadership in Virginia.

Bankruptcy Matters

On July 31, 1991, The Columbia Gas System, Inc. (Corporation) and its wholly-owned subsidiary, Columbia Gas Transmission Corporation (Columbia Transmission), filed separate petitions seeking protection under Chapter 11 of the Federal Bankruptcy Code. Both the Corporation and Columbia Transmission have been granted debtor-in-possession status under the Bankruptcy Code, allowing them to continue the normal operations of their businesses subject to the jurisdiction of the Bankruptcy Court.

Background

On June 19, 1991, the Corporation announced that: (1) it anticipated that a substantial portion of Columbia Transmission's exposure on above-market priced gas purchase contracts would be charged to income in the second quarter; (2) Columbia Transmission was launching a comprehensive effort to renegotiate or terminate all of its above-market gas purchase contracts under a program which contemplated offering producers up to $600 million of Columbia Transmission obligations as compensation for restructuring their contracts; (3) the Corporation was suspending the dividend on its common stock; and (4) corporate officers were meeting with bank lenders that day seeking to reestablish the Corporation's credit facilities on revised terms in view of Columbia Transmission's financial difficulties. In addition, Columbia Transmission's financial problems were exacerbated when the West Virginia Supreme Court ordered the posting of a $10 million bond by July 29, 1991, in order to stay the execution of a $29.5 million judgment in a lease dispute which was subsequently reversed.

As of July 31, 1991, the Corporation was in default on $83.5 million of short-term debt obligations and the negotiations with banks and producers had met with only limited success. As a result, on July 31, 1991, the Corporation and Columbia Transmission filed for protection under Chapter 11 of the Federal Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware (Bankruptcy Court). A discussion of the proceedings under Chapter 11 protection is included in Note 2 of Notes to Consolidated Financial Statements.

Bankruptcy Issues

Prepetition obligations of the Corporation primarily represent debentures, bank loans and commercial paper outstanding on the filing date together with accrued interest to that date. Columbia Transmission's prepetition obligations include secured and unsecured debt and accrued interest payable to the Corporation, estimated supplier obligations, estimated rate refunds, accrued taxes and other trade payables and liabilities.

On March 19, 1992, the Official Committee of Unsecured Creditors of Columbia Transmission (the

Columbia Transmission Creditors' Committee) filed a complaint (Intercompany Complaint) alleging that the $1.7 billion of Columbia Transmission's secured and unsecured debt securities held by the Corporation should be recharacterized as capital contributions (rather than loans) and equitably subordinated to the claims of Columbia Transmission's other creditors. The Intercompany Complaint also challenges interest and dividend payments made by Columbia Transmission to the Corporation of approximately $500 million for the period from 1988 to the petition date and the 1990 property transfer from Columbia Transmission to Columbia Natural Resources, Inc. (CNR) as an alleged fraudulent transfer. Based on the Securities and Exchange Commission (SEC) standardized measurement procedures, CNR's properties had a reserve value of $451 million as of December 31, 1992, a significant portion of which is attributable to the transfer from Columbia Transmission. Subsequently, the Columbia Transmission Creditors' Committee filed a motion for a jury trial and to transfer the Intercompany Complaint from the Bankruptcy Court to the U.S. District Court. In June 1992, the Corporation filed a motion with the Bankruptcy Court seeking dismissal of, or summary judgment on, principal portions of the complaint filed by the Columbia Transmission Creditors' Committee. On February 9, 1993, the U.S. District Court denied the Columbia Transmission Creditors' Committee motion which now permits the Bankruptcy Court to decide the Corporation's motion for summary judgment. Management believes that the Intercompany Complaint is without merit; however, the ultimate outcome of these issues is uncertain at this stage of the proceedings.

The Corporation continues to analyze reorganization plan scenarios. The primary goal is to achieve a consensual plan of reorganization which appropriately addresses the interests of the Corporation. Preliminary discussions with Columbia Transmission's creditors have commenced to establish the value of the estate, as well as consensually resolve the matters raised in the Intercompany Complaint. Since the standing and value of the Corporation's debt investment in Columbia Transmission is crucial to the determination of the value of the Corporation's estate, significant provisions of the Corporation's plan of reorganization cannot be known until further progress occurs on the Intercompany Complaint and bankruptcy proceedings.

At December 31, 1992, the Corporation's investment in Columbia Transmission is as follows:

	$ millions
Secured Debt	
First Mortgage Bonds	930.4
Gas Inventory Loan(s)	410.0
Accrued interest on secured debt	207.1
Unsecured Debt	
Installment Notes	343.9
Accrued interest to petition date	7.1
Equity investment	(499.0)
Total Investment	1,399.5

Depending upon the value of the Columbia Transmission estate, as well as the standing and value of the Corporation's debt investment, management is evaluating the feasibility of: (1) obtaining financing for reorganization, and/or (2) restructuring the Columbia Gas System.

Provisions of any such reorganization plan(s), or the inability of the Corporation and/or Columbia Transmission to obtain approval of a plan, could have a material adverse effect on the Corporation and its subsidiaries and on the rights of shareholders and holders of debt and other obligations.

The Internal Revenue Service (IRS) filed identical claims of $553.7 million against both debtor companies and the consolidated Columbia Gas System for tax deficiencies, interest and penalties for the tax years 1985–1990. Through year-end, negotiations with IRS representatives have resulted in tentative agreements on a number of issues and substantial progress on two of the remaining three issues. The accompanying financial statements reflect the effect of the tentative agreements.

The Corporation and the IRS are in the early stages of discussion on the remaining and most significant issue, the payments to producers under Columbia Transmission's 1985 producer settlement program. The IRS position on the producer payment issue, if sustained, could result in a deficiency of approximately $250 million. Management believes the deductions claimed in filed tax returns are appropriate and supportable and, accordingly, has not recorded any reserves for this issue.

Management recognizes the importance of resolving this issue due to the significant effect it could have on creditors, stockholders, and the reorganization objectives. Nevertheless, although management prefers to settle this issue through negotiations rather than protracted litigation, it retains all rights to pursue this latter alternative to achieve a favorable resolution. Although management believes its position on these issues is correct, it is not possible at this time to predict with certainty the outcome of negotiations with the IRS.

Columbia Transmission has recorded liabilities of approximately $1 billion to reflect the estimated effects of its above-market producer contracts and estimated supplier obligations associated with pricing disputes and take-or-pay obligations for historical periods. With Bankruptcy Court approval, Columbia Transmission has rejected more than 4,600 above-market gas purchase contracts with producers. The producers, whose gas purchase contracts were rejected, filed claims for damages in excess of $20 billion. The Bankruptcy Court has approved the appointment of a claims mediator to implement a claims estimation procedure related to the rejected above-market producer contracts and other producer claims. The resolution of these issues can significantly influence future reported financial results as accounting standards require that as claim amounts are allowed by the Bankruptcy Court, the full amount of the allowed claim must be recorded. This could result in liabilities being recorded which bear little relationship to the amounts ultimately required to be paid in settlement of those claims and could conceivably exceed the Corporation's total investment in Columbia Transmission. Any such distortion would not be corrected until final plans of reorganization are approved for the Corporation and Columbia Transmission.

Other Related Issues

Corporation's Objection to Claims

On July 29, 1992, the Bankruptcy Court approved procedures, as requested by the Corporation, for disposing of certain claims filed against the Corporation. On August 18, 1992, the Corporation filed objections to more than 7,100 proofs of claim filed against the Corporation. These objections largely sought to expunge claims made by bondholders, stockholders and commercial paper holders because stockholders are not creditors of the Corporation and because the debtholders' claims are duplicative of other claims made on the claimants' behalf by their representatives. The objections also sought to disallow, reduce or reclassify other claims. On January 12, 1993, the Bankruptcy Court issued an order granting the requested relief. As a result, only 400 of the approximately 7,500 claims filed against the Corporation remain to be resolved.

Leveraged Employee Stock Ownership Plan

On May 31, 1992, the debt service payment on debentures issued under the Leveraged Employee Stock Ownership Plan (LESOP) portion of the Columbia's Employees' Thrift Plan was not made and no further debt service payments are likely to be made until the Corporation emerges from bankruptcy. Management has concluded that it is more equitable and may be economically preferable to pay all creditors at the same time in accordance with consummation of the Corporation's Plan of Reorganization. Under the terms of the Corporation's guarantee of the debentures, the LESOP debenture holders will become creditors of the Corporation, subordinated to holders of the debentures and medium-term notes issued by the Corporation.

Property Taxes

On August 19, 1992, the Bankruptcy Court denied Columbia Transmission's motion to pay $6.7 million in West Virginia property taxes because they were determined to be prepetition expenses and, therefore, are subject to the automatic stay imposed by the Bankruptcy Code. The State of West Virginia and Columbia Transmission have appealed the ruling on the grounds that the taxes arose postpetition and should be paid as a normal operating expense.

Columbia Transmission Leases

On October 16, 1992, the Bankruptcy Court approved Columbia Transmission's request to assume more than 15,600 leases for natural gas storage facilities and other nonresidential real property. Assumption of these leases by Columbia Transmission will dispose of thousands of small claims which total about $1.2 million. Approximately 12,000 of the leases pertain to Columbia Transmission's underground natural gas storage operations with the remainder for company office buildings, operating centers, work locations, warehouses, equipment storage, and transmission measurement and regulating facilities, all of which are essential to the company's day-to-day operations.

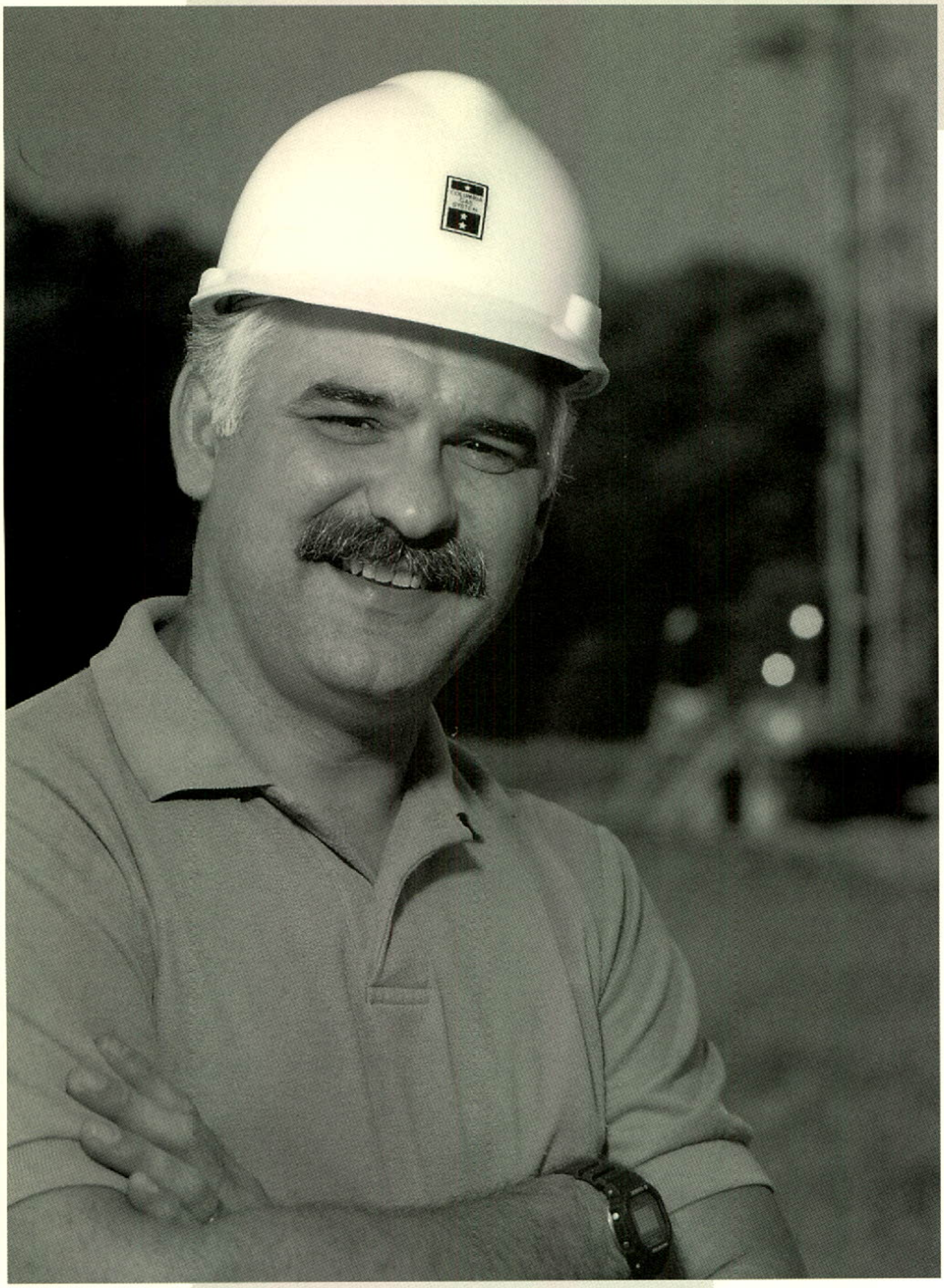
Customer Refunds

In July 1992, the U.S. District Court for the District of Delaware overturned a February 1992 Bankruptcy Court ruling which would have allowed Columbia Transmission to flow through to customers a portion of refunds from upstream pipeline suppliers related to prepetition periods and to pay prepetition surcharges collected from customers to the Gas Research Institute (GRI). The District Court decision stated that all such amounts are unsecured claims subject to distribution under Columbia Transmission's reorganization plan. Columbia Transmission and its customers have appealed the District Court decision to the U.S. Court of Appeals for the Third Circuit. The Federal Energy Regulatory Commission (FERC) filed a brief in support of Columbia Transmission's appeal on the customer refund flowthrough and GRI issues.

On October 15, 1992, the FERC authorized Columbia Transmission to suspend all remaining flowthrough payments to upstream pipelines and all related billings and billing adjustments to its customers pending the outcome of the appeals of the District Court decision.

Reorganization Plans

Until March 25, 1993, both the Corporation and Columbia Transmission have exclusive rights to file their individual plans of reorganization. It is anticipated that a request to extend this period of exclusivity will be submitted to the Bankruptcy Court.

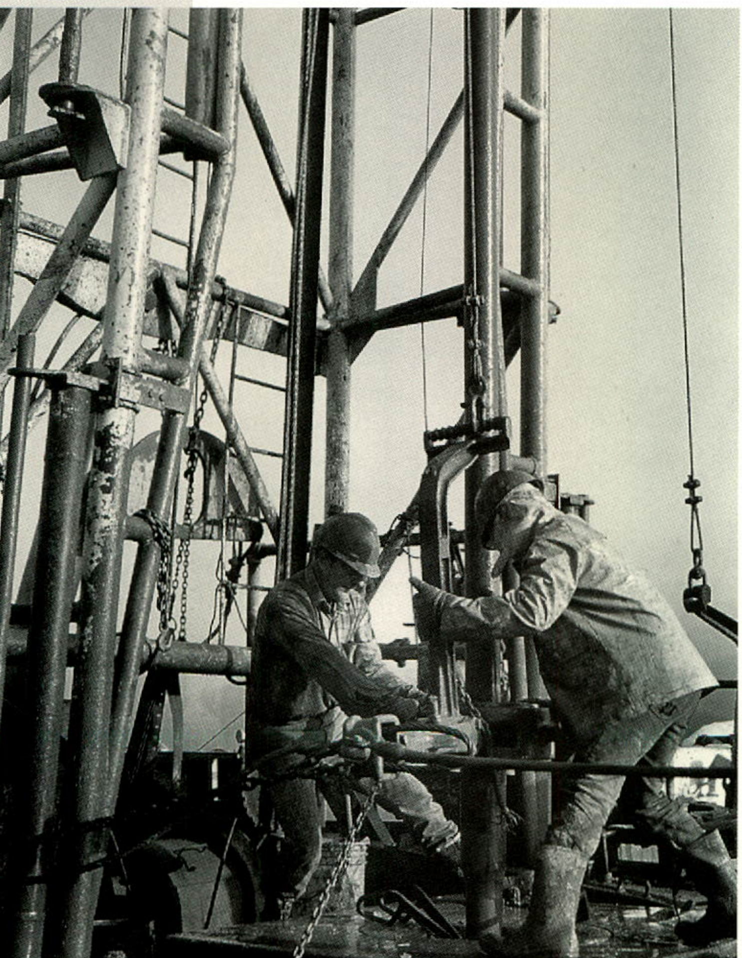


Dick Stollar and other Columbia Gas geologists are using computers to take the guesswork out of a challenging business. Processing geological data can be as simple as adding two numbers or as complicated as mathematically sorting millions of data points in three-dimensional space. Computer imaging helped Columbia Natural Resources' chief geologist redraw the underground map of a much-drilled Appalachian Basin prospect that other companies had largely written off. Once the attractive geological features were pinpointed, attention turned to a careful examination of the economics. Drilling costs? Reservoir size and characteristics? Lifting costs? Taxes? Before the drill bit touched the ground, Dick and other CNR employees had modeled the entire life cycle of the prospect. Today, Columbia Natural Resources is reaping the benefits of Dick's persistence and his careful scrutiny of the three-dimensional computer data, and the oil and gas produced from these efforts are creating value for Columbia shareholders.

OIL AND GAS

Market Conditions

In early 1992, natural gas prices collapsed to the lowest levels since the late 1970s due to the lingering effects of oversupply and warm weather. Prices later improved somewhat but remained at relatively low levels. Overall for 1992, the oil and gas segment received an average domestic natural gas price of $2.02 per thousand cubic feet of gas compared to $1.88 in 1991. Domestic oil prices continued their decline from a 1991 level of $22.18 per barrel to $18.20 per barrel for 1992. Columbia utilizes price-hedging techniques from time to time to manage the risk of price declines for its oil and gas production.



Capital Expenditures

Because of low energy prices in the early part of 1992, capital expenditures for the oil and gas segment during the year were reduced from an original estimate of $93 million to $71 million. The 1993 capital expenditure program will be held at a level of $69 million and limited to expenditures required to meet legal and contractual obligations, maintain future deliverability of existing reserves and meet safety considerations. In the Appalachian area, six exploratory wells will be drilled in 1993, and the number of development wells drilled will increase to 139. The Southwest 1993 drilling program will focus on development wells and certain activities, such as seismic testing and land acquisition, in order to allow additional exploratory drilling to commence in 1994.

Reserves

The reduced level of capital expenditures during 1992 limited the addition of new reserves by the oil and gas segment. Proved domestic natural gas reserves for 1992 of 779.5 Bcf compares to 808.1 Bcf at the end of 1991.

Statements of Operating Income from Oil and Gas Operations (Unaudited)*

Year Ended December 31 (in millions)	1992	1991	1990
Operating Revenues			
Gas	**$ 143.1**	$142.6	$153.9
Oil and liquids	**55.6**	72.2	61.1
Total Operating Revenues	**198.7**	214.8	215.0
Operating Expenses			
Operation and maintenance	**78.7**	78.3	62.6
Depreciation and depletion	**210.0**	130.1	98.5
Other taxes	**11.2**	10.9	10.6
Total Operating Expenses	**299.9**	219.3	171.7
Operating Income (Loss)	**$(101.2)**	$ (4.5)	$ 43.3

*Years 1991 and 1990 include results from Canadian operations that were sold effective December 31, 1991.

Proved domestic oil and liquids reserves declined approximately 900,000 barrels from the 1991 level of 15.6 million barrels. The limited 1993 capital program will probably result in a decrease of proved oil and natural gas reserves as production will likely exceed reserve additions.

Southwest

Columbia Gas Development Corporation (Columbia Development) achieved a 42% success rate for the 24 gross (21 net) exploratory wells in which it was a participant in 1992. Of particular significance was a horizontal exploratory well drilled on a 56,000-acre block in Grand County, Utah, which tested at a rate of 1,325 barrels of oil and 879,000 cubic feet of gas per day. This was the fourth in a series of wells Columbia Development drilled to develop reserves in the Kane Springs area. Kane Springs is located on federal land on which 10 drilling permits will be granted. Eight have been assigned. Columbia Development is currently pursuing the rights to the remaining two permits.

Several additional significant discoveries were drilled during the year in Louisiana. These discoveries tested at a combined rate of 1,592 barrels of oil and 4.4 million cubic feet of gas per day. Two of these discoveries occurred in the South Harmony Church area. Four 100% interest development wells are planned for this area during 1993. When fully developed, it is anticipated the field will produce 2,000 to 3,000 barrels of oil daily.

During 1992, 46 gross (21 net) development wells were drilled with a success rate of 85%. Of these, 33 gross (14 net) were horizontal development wells and 13 gross (7 net) were vertical development wells. The more significant development wells occurred on horizontal projects in the Austin Chalk Trend of South Texas. Nine of these wells tested at a combined rate of 12,172 barrels of oil and 5.6 million cubic feet of gas per day. The most significant of these nine was the Double Eagle Ranch #1 located in Lee County, Texas, which tested at a rate of 1,611 barrels of oil and 713,000 cubic feet of gas per day. This well produced 175,000 barrels of oil during the second half of 1992.

A secondary oil recovery project in Huntington Beach, California, commenced production during 1992 using water injection technology. By late 1993, oil production is expected to reach approximately 2,400 barrels per day. Columbia Development owns a 50% working interest in the project. It is anticipated that this project will eventually include 16 producing wells.

The 1993 program for Columbia Development includes 45 gross (20 net) development wells. In addition to the 1993 program, 7 gross (4 net) development wells and 3 gross (3 net) exploratory wells carried over from the 1992 drilling program.

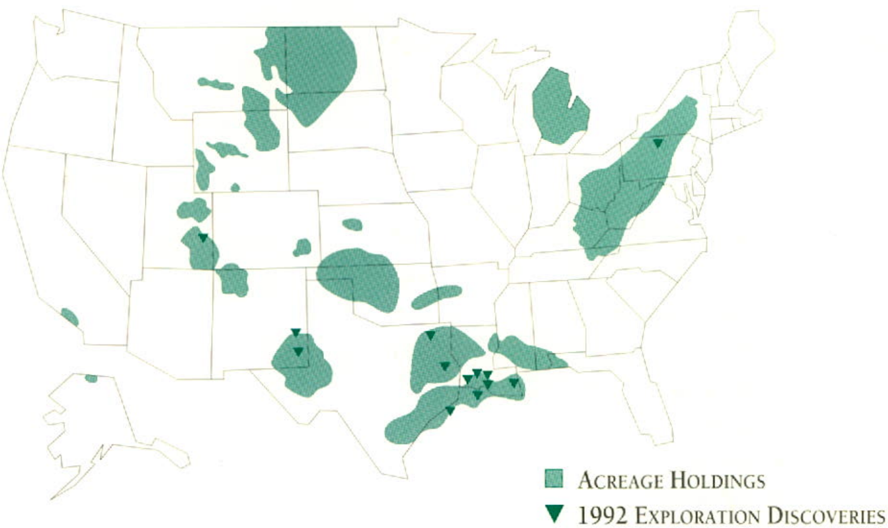
Appalachia

Columbia's drilling activity in the Appalachia area decreased 62% from 1991 to a level of 42 gross (25 net) wells. This total includes 40 gross (23 net) development wells with a success rate of 86% and two exploratory wells of which one was successful. The 1992 program concentrated on development of known prospects. The 1993 drilling program includes 139 development wells (81 net) and 6 exploratory wells (5 net).

Volumes

Domestic natural gas production in 1992 remained relatively unchanged from 1991 levels. However, total production declined 6 Bcf due to the sale of the Canadian operations effective December 31, 1991. In 1991, depressed energy prices, resulting from warmer than normal weather and an oversupply situation, led to a decline in domestic gas production of 3%, or 2 Bcf, from 1990, while production from Canadian operations increased 3 Bcf.

DOMESTIC ACREAGE HOLDINGS



The success of the Southwest exploration and development program continued during 1992 as domestic oil and liquids production increased 228,000 barrels from the prior year. This was offset by the sale of Canadian properties which reduced production by 578,000 barrels. In 1991, Columbia Development's horizontal drilling program was the primary cause of the 723,000-barrel increase in total production over 1990.

Operating Revenues

The sale of the Canadian subsidiary was the primary reason for lower operating revenues of $198.7 million during 1992, a decline of $16.1 million when compared to 1991. The Canadian subsidiary had gas revenues of $6.5 million and oil revenues of $9.2 million in 1991.

A rebound in domestic natural gas prices in the latter part of 1992 caused the average price to increase $0.14 to $2.02 per Mcf. This increase was sufficient to offset a decrease in gas revenues as a result of the sale of the Canadian subsidiary. In 1991, a decline in gas prices coupled with declines in domestic production led to the $11.3 million decrease in operating revenues compared to 1990.

A decline in the average price received for domestic oil and liquids production to $18.20 per barrel from $22.18 per barrel in 1991 resulted in a $12.1 million decrease in domestic oil and liquids revenues. Increased production during 1992 added $5 million to oil and liquids revenues. Increases in 1991 production more than offset price declines when compared to 1990 and led to an $11.1 million rise in oil and liquids revenue.

Operating Income (Loss)

The oil and gas segment recorded a $126.4 million writedown in the carrying value of U.S. oil and gas properties in the first quarter of 1992 due to depressed energy prices. This was the primary reason for the $101.2 million operating loss for the year. This writedown, combined with higher operating expenses, partially offset by losses incurred in 1991 for the Canadian oil and gas operation, caused the $96.7 millon decrease from the prior year. In 1991, depressed energy prices combined with Canadian writedowns of $36.4 million and increased operation and maintenance expense resulted in $47.8 million lower operating income compared to 1990.

OIL AND GAS OPERATING HIGHLIGHTS*

	1992	1991	1990	1989	1988
Capital Expenditures ($ in millions)	**70.8**	120.8	229.0	147.9	71.1
Proved Reserves					
Gas (Bcf)	**779.5**	808.1	925.7	902.7	897.8
Oil and Liquids (000 barrels)	**14,650**	15,568	18,991	16,731	14,904
Production					
Gas (Bcf)	**69.2**	76.3	75.3	77.7	74.6
Oil and Liquids (000 barrels)	**3,061**	3,411	2,688	1,924	2,328
Average Prices					
Gas ($ per Mcf)	**2.02**	1.81	2.00	1.89	1.72
Oil and Liquids ($ per barrel)	**18.20**	21.10	22.86	16.71	13.20

*Years 1991 through 1988 include results from Canadian operations that were sold effective December 31, 1991.

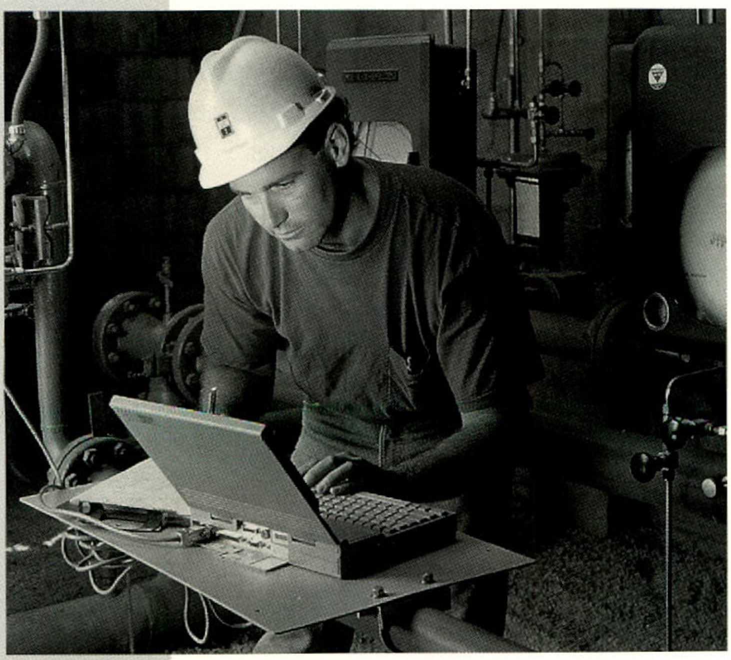
As a customer service representative, Janet Shobe is often the only personal contact Columbia Transmission's customers have with the pipeline network. To service their needs, Janet relies on strong communications skills and the up-to-the-minute information she retrieves from Columbia's state-of-the-art electronic measurement system. When a customer calls to check on flowing gas supplies, Janet can give the customer accurate data immediately because the measurement system is continuously updated for all of Transmission's major delivery points. With this information at her fingertips, Janet is a vital link in helping Columbia build its reputation as the best choice for transportation service in today's competitive natural gas market. Although few customers actually see Jim Ogg, his technical abilities serve them daily. As a meter mechanic for Columbia Transmission, Jim makes certain the electronic measurement equipment works correctly and with significantly greater accuracy and timeliness than the previous generations of equipment. Janet Shobe and Jim Ogg, along with other Columbians, help make the transmission companies' commitment to excellent customer service a reality.

TRANSMISSION

Marketing Initiatives

During 1992, Columbia Transmission completed construction required to provide Piedmont Natural Gas Company with 73,000 Mcf per day of firm transportation service and Virginia Power with approximately 41,700 Mcf per day of firm transportation. In addition, Columbia Transmission filed an application with the FERC in May 1992 requesting authority to construct facilities to provide a paper mill in Virginia with approximately 4,100 Mcf per day of firm transportation service. Deliveries are scheduled to begin during November 1993.

Columbia Transmission has also been pursuing opportunities to provide additional transportation services to cogeneration facilities.



The FERC's approval has been received for construction of the Rutledge Compressor Station in Harford County, Maryland, that is necessary to provide full service to the Eagle Point Cogeneration Plant in New Jersey of 53,400 Mcf per day and over 59,000 Mcf per day to New England Power (NEP) in Massachusetts. Rutledge is scheduled to be placed in service during 1994 to meet NEP's anticipated increased energy requirements. In September 1992, Columbia Transmission filed an application with the FERC for authority to construct facilities to provide 15,700 Mcf per day of firm transportation service to a cogeneration project in Olean, Cattaraugus County, New York. The party that is constructing the 79-megawatt cogeneration facility will also provide Columbia Transmission with the funds necessary for construction of the pipeline facilities. The proposed cogeneration facility will sell electric power to Niagara Mohawk Power Company. Service is scheduled to begin in December 1993. During July 1992, Columbia Transmission increased transportation service by approximately 11,700 Mcf per day to a cogeneration project in Binghamton, New York. The 50-megawatt facility produces electric power that is sold to New York State Electric and Gas Company and thermal energy that is sold to Anitec Image Corporation. Transportation is being provided under Columbia Transmission's off-peak firm transportation service.

Statements of Operating Income from Transmission Operations (Unaudited)

Year Ended December 31 (in millions)	1992	1991	1990
Net Revenues			
Sales revenues	**$924.8**	$ 609.2	$479.9
Less: Cost of gas sold	**654.4**	391.0	195.0
Net Sales Revenues	**270.4**	218.2	284.9
Transportation revenues	**449.0**	430.8	396.8
Less: Associated gas costs	**71.7**	104.0	100.3
Net Transportation Revenues	**377.3**	326.8	296.5
Storage Revenues	**113.7**	89.5	65.9
Net Revenues	**761.4**	634.5	647.3
Operating Expenses			
Provision for gas supply charges	**38.6**	1,319.2	–
Operation and maintenance	**438.3**	357.7	384.4
Depreciation	**95.6**	90.4	86.9
Other taxes	**59.0**	59.4	47.8
Total Operating Expenses	**631.5**	1,826.7	519.1
Operating Income (Loss)	**$129.9**	$(1,192.2)	$128.2

Order No. 636

In April 1992, the FERC issued Order No. 636 (Order 636), its final rule on Pipeline Service Obligations and Equality of Transportation Services by Pipelines. The FERC states that this order is the final stage in its effort to fundamentally change the role of pipelines from providing a merchant function to one in which they perform principally as transporters of gas that distribution companies and end users purchase directly from producers and other suppliers.

Order 636 requires pipelines to "unbundle" their sales, transportation and storage services and to provide and price these services separately. In addition, Order 636 requires changes to pipeline rate design which it believes will improve competitiveness of pipeline rates and provide more accurate market signals between gas buyers and sellers. The FERC ordered all pipelines to implement Order 636 before the 1993-94 winter and has established restructuring proceedings for each pipeline. In December 1992, Columbia Transmission and Columbia Gulf Transmission Company (Columbia Gulf) made their compliance filings with the FERC, setting forth each company's proposal for compliance with Order 636 by the mandated date of November 1, 1993.

In Order 636, the FERC provided that pipelines may recover all prudently incurred costs resulting from the transition to Order 636 and set general guidelines for their recovery. However, the FERC stated that filings to recover such costs should not be made until a pipeline's service restructuring proposal has been approved by the FERC. While Columbia Transmission's and Columbia Gulf's compliance filings identified various transition costs, actual filings to recover such costs will be made at a later date. The compliance filings contemplate collection of estimated transition costs in several areas. With respect to gas supply realignment costs, and costs associated with reforming or terminating above-market price gas supply contracts, Columbia Transmission noted in its filing that the majority of such costs on its system will be determined in the context of the bankruptcy proceedings regarding the determination of producer contract rejection costs. The company stated that the ultimate level of such costs is uncertain and that recovery would be pursued in future filings with the FERC. In February 1993, responses to the transmission companies' compliance filings were filed with the FERC by interested parties seeking to exclude from transition costs certain producer contract rejection costs. Columbia Transmission's efforts to recover gas supply realignment costs are expected to be strongly opposed.

Recovery of other transition costs by Columbia Transmission will be important to its prospective operating results. Purchased gas costs associated with Columbia Transmission's merchant function not yet collected from customers are estimated to be in the range of $150 million to $175 million at November 1, 1993. Further, the compliance filing details procedures to offer Columbia Transmission's customers its existing firm capacity on upstream pipelines, with demand charge commitments of approximately $108 million annually. Management expects a significant portion of such capacity to be acquired by existing customers, and therefore, any remaining Columbia Transmission commitments should be significantly below current levels. The filing also addresses the potential that some portion of Columbia Transmission's net investment in gathering facilities ($68 million at December 31, 1992) may be considered a stranded investment for which recovery in rates would be requested. The amount of any such stranded facilities depends upon the existing rate design in effect and the results of efforts which may be undertaken to sell or otherwise dispose of such properties and other factors. As noted above, filings to recover any such costs will not occur until the compliance filing is approved. Therefore, the ultimate outcome cannot be predicted with certainty. Based upon provisions of Order 636, which permit recovery of all prudently incurred costs, management believes that substantially all of these costs will be recovered.

Under its restructuring proposal, Columbia Transmission will offer customers 16 different services, including firm, off-peak firm and interruptible transportation services, firm and interruptible storage services, a no-notice firm transportation service, and firm and interruptible gathering services. Columbia Transmission anticipates providing only a minimal merchant function to some of its small general service customers after November 1, 1993, and will offer to all of its former sales customers a portion of almost all its storage capacity as well as the transportation capacity it has historically held on upstream pipelines, including Columbia Gulf. Order 636 also provides that pipelines collect rates based on the straight fixed variable (SFV) cost allocation and rate design. While not eliminating the risks a pipeline may face in collecting its cost-of-service, the SFV methodology generally provides that a pipeline can collect its fixed costs, including its allowed return in its demand charges, the monthly reservation fee customers pay to reserve pipeline capacity regardless of actual usage. Variable costs associated with actual usage of capacity will be recovered through a volumetric charge.

Cove Point LNG Terminal

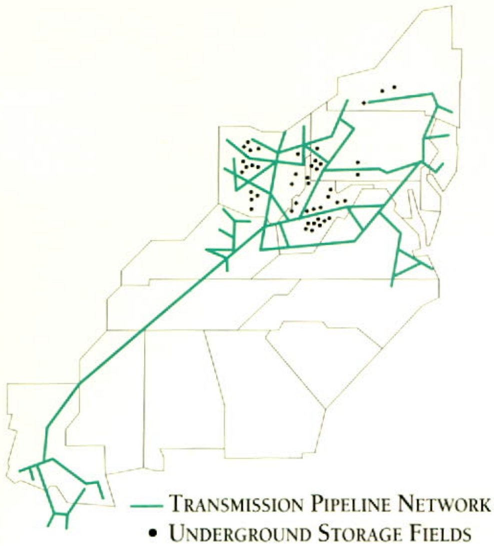
Columbia LNG Corporation (Columbia LNG) has developed a new business plan for its Cove Point, Maryland, terminal. This plan provides for a new peaking service by the end of 1994, as well as terminalling service for liquefied natural gas received by tanker. An application for these services was filed with the FERC in February 1993, which proposes to charge customers based upon individually negotiated market rates. In accordance with the business plan and in anticipation of the FERC filing, management concluded it is no longer appropriate for Columbia LNG to continue application of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," and regulatory assets have been removed from Columbia LNG's balance sheet, resulting in an extraordinary charge of $60.1 million pre-tax ($39.7 million after-tax) being recorded in the third quarter of 1992.

Discussions with potential customers have yielded positive indications to date regarding the viability of this new business plan. An open season, allowing customers to bid on the capacity of all of the offered services, will be held after the FERC certificate filing is noticed. The realization of the Corporation's remaining investment in Columbia LNG of $51.9 million will be dependent upon successful implementation of the business plan.

It is estimated that the cost of reactivating the facility will be approximately $40 million if only a peaking service is offered and $55 million if both a peaking and a terminalling service are offered. (See Note 12G in Notes to Consolidated Financial Statements for more information.)

Pipeline Supplier Direct Billings

Columbia Transmission's pipeline suppliers have revised their allocation of take-or-pay costs previously billed to Columbia Transmission as a result of FERC Order No. 528. Columbia Transmission has or will receive refunds from almost all of these upstream suppliers. The Bankruptcy Court held that Columbia Transmission may only flow through to customers a very small portion of the refunds received prepetition and all of the take-or-pay refunds received postpetition. The United States District Court for the District of Delaware reversed the Bankruptcy Court decision and ruled that all prepetition refunds are the property of Columbia Transmission's estate and cannot be flowed through to the customers. Columbia Transmission and the Official Committee of Customers, among others, have appealed this decision to the U.S. Court of Appeals. The FERC filed a brief with the U.S. District Court supporting the flowthrough of refunds. One of these pipeline suppliers, Tennessee Gas Pipeline Corporation, filed a settlement with the FERC in 1991



which was intended to resolve numerous outstanding issues, including its allocation of take-or-pay costs. The settlement reduced take-or-pay flow-through costs allocated to Columbia Transmission from approximately $200 million to approximately $80 million, excluding interest. As a result of payments made under the prior allocation method, Columbia Transmission anticipates receiving a refund of approximately $65 million including interest. In June 1992, the FERC approved the settlement, with certain amendments. Refunds to Columbia Transmission in three equal semi-annual installments commenced in January 1993.

Columbia Transmission previously reached a settlement with Kentucky West Virginia Gas Company (Kentucky West Virginia) concerning Kentucky West Virginia's filing to retroactively collect higher prices for gas it produced and sold between 1979 and 1983. However, the settlement was rejected by the FERC in 1991. In August 1992, Kentucky West Virginia and Columbia Transmission filed a revised settlement with the FERC that includes a bankruptcy claim of $19 million relating to higher prices for Kentucky West Virginia's gas production for prior years and a $7 million bankruptcy claim pertaining to Columbia Transmission's rejection of its gas purchase contract with Kentucky West Virginia. On November 6, 1992, the Bankruptcy Court approved Columbia Transmission's rejection of the original Kentucky West Virginia contract. Through 1992, Columbia Transmission has recorded liabilities totalling $26 million to reflect the proposed settlement. The settlement was approved with modifications by the FERC in February 1993. If the modifications are acceptable to Columbia Transmission and Kentucky West Virginia, it will be submitted for Bankruptcy Court approval.

Rate Cases

Columbia Transmission's and Columbia Gulf's rates are established by the FERC. The companies make periodic requests for rate changes to recover costs associated with new facilities, higher operating or capital costs, or to reflect changes in throughput, cost allocation or rate design. The settlements related to these filings are subject to the FERC and, during the pending bankruptcy of Columbia Transmission, Bankruptcy Court approval.

As of the end of 1992, Columbia Transmission and Columbia Gulf had several such rate settlements awaiting the FERC's approval. In October 1992, the FERC issued an order approving proposed settlements filed by Columbia Transmission and Columbia Gulf resolving all issues pending in a 1990 rate filing. This settlement is contingent on Columbia Transmission being allowed by the Bankruptcy Court to make full refunds of revenues collected in excess of the settled rates for prepetition and postpetition periods. An annual revenue increase of $89 million, over the prior rates which were in effect, will result from the settlement. The settlement remains subject to Bankruptcy Court approval.

During 1991 Columbia Transmission filed a general rate case effective December 1, 1991, to:

- permit recovery of increased costs since the last general rate filing,
- implement other changes in the cost of service, throughput, and demand billing determinants through the end of the test period,
- make certain changes to its FERC gas tariff, and
- make certain changes in cost classification, cost allocation, and rate design to be effective April 1, 1992, the expiration date of the rate design moratorium as provided for in a 1989 customer settlement.

The additional increased revenues amount to approximately $35 million annually compared to the underlying filed rates. Columbia Transmission and Columbia Gulf have settled all issues set for hearing in these rate cases, as well as the cost allocation and rate design for the period preceding implementation of restructuring under Order 636. Generally, the settlement resolves the cost of service, throughput levels and rate design upon which Columbia Transmission and Columbia Gulf would establish their rates. In addition, the agreement reflects utilization of the as-filed cost allocation and rate design for past periods, and implementation of a revised rate design from November 1, 1992, until the pipelines implement Order 636. This settlement provides for an annual revenue increase of $22 million. Columbia Transmission has agreed to waive implementation of the bidding procedures relating to its interruptible transportation rate schedule, which were proposed to be effective in November 1992. An Administrative Law Judge certified the settlement to the FERC in December 1992 where it is pending approval. However, certain parties have filed in opposition to this settlement agreement.

Environmental Matters

Columbia Transmission and Columbia Gulf are subject to extensive federal, state and local laws and regulations relating to environmental matters. These laws and regulations, which are constantly changing, require expenditures for corrective action at various operating facilities and waste disposal sites for conditions resulting from past practices that subsequently were determined to be environmentally unsound.

The transmission subsidiaries have received notice from the United States Environmental Protection Agency (EPA) that they are among several parties responsible under federal law for placing wastes at Superfund sites and may be required to share in the cost of remediation of these sites. However, considering known facts, existing laws and possible insurance and rate recoveries, management does not believe the identified Superfund matters will have a material adverse effect on future annual income or on the Corporation's financial position.

The management of the transmission subsidiaries is continuing its own ongoing comprehensive review of compliance with existing environmental standards, including review of past operational activities and identification of potential site problems, thorough site reviews and formulation of remediation programs where necessary. While the Corporation's transmission subsidiaries have made progress in these ongoing self-assessment programs, because of the thousands of miles of pipeline which they operate, the exceptionally large number of sites at which they conduct or have conducted operations, and the long period over which operations have been conducted, completion of site screenings, characterizations and, if required, site-specific remediations will take a considerable period of time. In addition, the Chapter 11 proceeding of Columbia Transmission adds complexity to addressing environmental issues as some governmental agencies may seek to have their claims resolved in the Bankruptcy Court.

In 1992, Columbia Transmission received a subpoena and information request (Request) from the EPA regarding three major environmental statutes: The Toxic Substance Control Act (TSCA), the Resource Conservation and Recovery Act (RCRA), and the Comprehensive Environmental Response Compensation and Liability Act (CERCLA). The Request relates to Columbia Transmission's past and current environmental practices. Since receipt of the Request, Columbia Transmission has provided the EPA with various materials regarding the Request. Columbia Transmission is meeting with the EPA to attempt to resolve the subpoena issues and continues to work cooperatively with environmental officials in the various states in which it operates.

As a consequence of its self-assessment program, Columbia Transmission in recent years has recorded projected compliance costs relating to the remediation of low levels of contamination by PCB-based lubricating oils used in certain air compressors, and other pollutants, including mercury. Further progress by Columbia Transmission in its self-assessment activities resulted in additional pre-tax charges of $65.3 million during 1992. These additional charges relate primarily to: 1) site characterization for pipeline and compressor station operations, 2) other investigatory costs to assess levels of contamination from non-PCB petroleum hydrocarbon occurrences and other regulated compounds, and 3) changes in established reserves for mercury contamination at certain sites and for low-level PCB contaminations in the compressed air systems. These and other minor adjustments bring Columbia Transmission's recorded net liability to approximately $100 million at December 31, 1992.

As characterization and site-specific activities by Columbia Transmission determine the possible existence, nature and extent of contamination, if any, at several thousand sites and operating facilities and as remediation plans are developed, additional charges to earnings will occur. To the extent such plans require approval of federal and/or state authorities, they may be subject to revision. Until assessment progresses further, management lacks sufficient data to predict the magnitude of all required costs. Based on the limited data now available and on various assumptions as to characterization, management believes that annual future expenditures for Columbia

Transmission's site investigations, characterization and remediation activities could be at the rate of approximately $20 million per year over the next 10 to 12 years, including costs already accrued. Earnings will continue to be charged appropriately in advance of required expenditures.

It is management's continued intent to address environmental issues with the cooperation of regulatory authorities in such a manner as to achieve mutually acceptable compliance plans. However, there can be no assurance that fines and penalties will not be incurred.

The eventual total cost of full future environmental compliance for Columbia Transmission and Columbia Gulf is impossible to estimate due to, among other things: (1) the possibility of as yet unknown contamination, (2) the possible effect of future legislation and new environmental agency rules, (3) the possibility of future litigation, (4) the possibility of future designations as a potentially responsible party by the EPA and the difficulty of determining liability, if any, in proportion to other responsible parties, (5) possible insurance and rate recoveries, and (6) the effect of possible technological changes relating to future remediation.

Management expects most environmental assessment and remediation costs to be recoverable through rates. Although significant charges to earnings could be required prior to rate recovery, management does not believe that environmental expenditures will have a material adverse effect on the Corporation's financial position based on known facts, existing laws and regulations and the period over which expenditures are required.

Clean Air Act Amendments of 1990

Columbia Transmission has completed a preliminary study to determine the impact of the Clean Air Act Amendments of 1990 (CAA-90). The study focused on 27 compressor facilities in five states. The facilities are among those affected by the new nitrogen oxide emission standards under CAA-90. It has been estimated that capital expenditures necessary to comply with these new standards could be $32 million over the next three years. However, due to the preliminary nature of the studies, the uncertainty of individual state regulations and other variables, the actual amount of future expenditures related to CAA-90 is difficult to estimate. Management anticipates that all capital expenditures made in compliance with CAA-90 will be recoverable through the rate-making process.

Volumes

Throughput for 1992 increased to 1,741 Bcf, or 14% over the previous year, reflecting 83 Bcf and 130 Bcf of higher sales and transportation volumes, respectively. Weather, which was 10% colder than 1991, and timing changes for prepaid gas sales, were the principal reasons for the sales increase; however, the favorable effect of Columbia Transmission's market-sensitive commodity rate, resulting largely from the rejection of noncompetitive above-market gas purchase contracts, also improved sales. Transportation volumes were higher principally due to customers using firm transportation services to move gas purchased from third parties to storage for future delivery under the terms of Columbia Transmission's firm storage service (FSS). Continuing the trend experienced over the past few years, firm transportation increased as customers moved from interruptible transportation services to more secure transportation arrangements to ensure deliverability of gas purchased from third parties. Lower-margin short-haul transportation volumes were 60 Bcf higher, reflecting additional arrangements made by marketers and customers for spot-market gas deliveries. Short-haul transportation has been increasing in recent years as customers continue to take advantage of lower-priced spot-market gas.

In 1991, throughput was 1,527 Bcf, an increase of 10% over the prior year. Compared to 1990, sales were up 23 Bcf and transportation increased 118 Bcf. Colder weather in 1991 accounted for most of the increase in sales volumes while transportation was higher due in large part to customers using transportation services to take advantage of Columbia Transmission's FSS. Short-haul transportation was also 67 Bcf higher, reflecting increased spot-market gas deliveries.

Net Revenues

Columbia Transmission's and Columbia Gulf's new rate designs, together with increased throughput, were the principal reasons for net revenues increasing to $761.4 million for 1992, an increase of $126.9 million over last year. Under the new rate design, a significant portion of the fixed costs, including a return and taxes, are collected in a monthly demand (capacity) charge and variable costs, such as gas costs, are reflected in commodity (usage) charges.

Net sales revenues were $52.2 million higher than last year as a result of the increased demand revenues allowed under the new rate design and higher sales volumes. In addition, $20.9 million of revenues were collected in the fourth quarter of 1992 under the terms of Columbia Transmission's gas inventory charge (GIC). It permits a charge to customers whose purchases fall below a predetermined level, provided Columbia Transmission's cost of gas meets a comparability test with competing pipelines, to partially compensate for incurred gas supply management costs.

Higher demand revenues for firm transportation services led to the $50.5 million improvement in net transportation revenues. In addition to the new rate design, demand revenues were also higher because customers switched to firm transportation services from other arrangements. Implementing the new rate design also improved storage service revenues by $24.2 million.

Net revenues for 1991 decreased from the 1990 level by $12.8 million. Net sales revenues were down $66.7 million, while transportation revenues and storage revenues increased $30.3 million and $23.6 million, respectively. The net sales revenue decline in 1991 compared to 1990 was primarily attributable to the effect of favorable one-time items recorded in 1990, including $30.5 million for a favorable court ruling allowing Columbia Transmission to recoup costs previously paid to other pipelines for expenses related to natural gas production. In addition, $22 million of GIC revenues were collected by Columbia Transmission in 1990. Net transportation revenues were higher in 1991 due to an increase in transportation volumes and higher demand revenues resulting from customers moving to firm transportation services. Lower average rates for short-haul transportation more than offset an increase in volumes transported. An increase in 1991 revenues of $23.6 million over 1990 for Columbia Transmission's storage service reflected the continued increase in customer utilization of this service together with the full-year effect of higher rates allowed by 1990 rate settlements.

Operating Income (Loss)

Transmission's 1992 operating income was $129.9 million, which compares to a loss of $1,192.2 million for 1991. The major cause of the increase was the 1991 provision for gas supply charges of $1,319.2 million. Eliminating the impact of bankruptcy and other unusual items, Transmission's operating income would have improved $62.1 million due to increased throughput and rate design changes. Increased reserves for future environmental costs and a writedown of previously capitalized gas costs due to the eventual elimination of the merchant function had a negative effect on current-year income.

After adjusting for the 1991 provision for gas supply charges mentioned above, 1991 operating income was essentially unchanged from the 1990 level of $128.2 million.

TRANSMISSION OPERATING HIGHLIGHTS

	1992	1991	1990	1989	1988
Capital Expenditures ($ in millions)	**114.2**	152.9	279.5	189.5	102.6
Throughput (Bcf)					
Sales	**196.0**	112.6	89.2	408.2*	369.3
Transportation					
Firm	**581.6**	418.1	319.4	195.6	108.3
Interruptible	**338.4**	431.8	480.1	627.7	504.3
Short-haul	**625.0**	564.7	497.4	387.4	268.5
Total	**1,545.0**	1,414.6	1,296.9	1,210.7	881.1
Throughput	**1,741.0**	1,527.2	1,386.1	1,618.9*	1,250.4
Sources of Gas for Throughput (Bcf)					
Sources of Gas Sold					
Spot Market	**66.3**	1.9	20.1	1.1	–
Producers	**106.7**	152.3	227.7	232.0	356.6
Pipelines	**–**	0.5	4.7	16.0	32.0
Storage withdrawals (injections)	**25.1**	24.5	(175.6)	184.6	(19.2)
Exchange	**32.1**	(37.8)	17.5	(14.5)	4.1
Other	**(34.2)**	(28.8)	(5.2)	(11.0)	(4.2)
Total Sources of Gas Sold	**196.0**	112.6	89.2	408.2	369.3
Transportation received from pipelines and producers	**1,545.0**	1,414.6	1,296.9	1,210.7	881.1
Total Sources	**1,741.0**	1,527.2	1,386.1	1,618.9	1,250.4

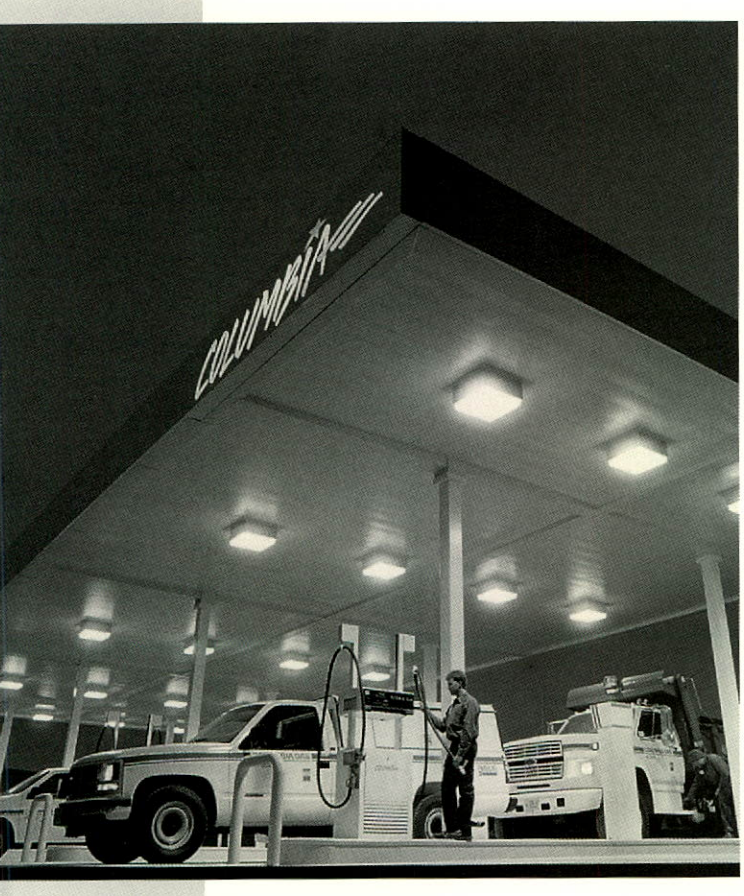
*Includes 116 billion cubic feet applicable to the sale of storage inventory gas.

Developing the market for natural gas vehicles (NGVs) is more than a job for Tim Davis. It's a passion. In addition to his eloquent promotion of natural gas vehicles, the manager of NGV market development for Columbia's distribution companies has helped generate industry standards that have given natural gas a solid advantage in this major market. As new federal environmental and energy legislation set future standards for improved vehicle emissions, Tim and other natural gas vehicle specialists are working to strengthen the foothold that natural gas has established. Columbia's commitment to establishing an NGV fueling infrastructure was clearly demonstrated with the dedication of the nation's largest public access fueling station. The company is also working with automakers and oil companies to make sure factory-built natural gas vehicles and public fueling facilities are in place to meet the demands of fleet owners and the public for vehicles that will meet tomorrow's clean air standards. As Tim Davis points out, "It's a market with unlimited potential for natural gas and enormous benefits for the nation's environment. NGVs increase year-round demand for natural gas while helping us all breathe a little easier. What more could you ask?"

D I S T R I B U T I O N

Market Conditions

1992 was the third consecutive year that temperatures were warmer than normal, but the second straight year that they were colder than the prior year. Weather continues to have a significant influence on sales for the distribution companies (Distribution). Despite a sluggish economy, Distribution added about 28,000 net residential and commercial customers in 1992.



The Clean Air Act of 1990 provides opportunities for natural gas to fuel electric power generation facilities and for converting coal-fired industrial boilers to natural gas. Natural gas deliveries to Distribution's power generation market now exceeds 19 Bcf per year. Throughput growth in this market is expected to increase 10% annually over the next five years. An industrial customer in Parma, Ohio, and another in Haverhill, Ohio, each converted coal boilers to natural gas, resulting in increased annualized throughput of 1.3 Bcf. Further development of this potential market will depend on whether adequate upstream pipeline capacity can be obtained to transport the large volumes required by electric power plants and whether clean-coal technologies will reduce the need to convert to natural gas. The Public Utilities Commission of Ohio (PUCO) recently issued its Ohio Energy Strategy Interim Report affirming the need to focus on natural gas to service more of Ohio's energy needs. This report will serve as the foundation for a long-term energy strategy within the state.

New business opportunities are also being pursued by Distribution outside of its core markets. Natural gas vehicles (NGVs) and power generation

Statements of Operating Income from Distribution Operations (Unaudited)*

Year Ended December 31 (in millions)	1992	1991	1990
Net Revenues			
Sales revenues	$1,574.2	$1,466.9	$1,380.0
Less: Cost of gas sold	945.3	882.2	819.9
Net Sales Revenues	628.9	584.7	560.1
Transportation revenues	73.4	66.6	45.2
Less: Associated gas costs	5.8	5.8	(17.1)
Net Transportation Revenues	67.6	60.8	62.3
Net Revenues	696.5	645.5	622.4
Operating Expenses			
Operation and maintenance	382.7	353.9	351.0
Depreciation	57.6	60.5	59.8
Other taxes	118.5	116.2	114.9
Total Operating Expenses	558.8	530.6	525.7
Operating Income	$ 137.7	$ 114.9	$ 96.7

*Includes Columbia Gas of New York, Inc. through March 31, 1991.

facilities are two such opportunities. Columbia Gas of Ohio opened the nation's largest public fueling station which provides 24-hour fueling services. The facility is fully automated and can fuel 12 vehicles simultaneously. In Virginia, Commonwealth Gas Service (COS) is assisting in the conversion of natural gas fleet vehicles operated by the Virginia Department of Transportation and the development of a fueling station to service these vehicles.

While industrial and commercial throughput increased for the year, there remains an ongoing concern for market loss due to bypass or competition from oil. Distribution faces bypass from local producers, other distribution companies, and intrastate and interstate pipelines, but to date it has been able to overcome this risk through competitive marketing approaches. Competition from oil might intensify if interstate pipeline restructuring costs from FERC Order 636 become significant and are reflected in end-user rates.

Rate Cases

A general rate case requesting additional revenues of $10 million annually was filed by COS in May 1992, with the Virginia State Corporation Commission. Increased rates went into effect, subject to refund, in October 1992 pending approval by the commission. These rates will allow recovery of actual costs of providing customer services, including increases in the cost of operations and the cost of capital invested to maintain quality service. A final decision is expected in mid-1993. An expedited rate case was filed by Columbia Gas of Maryland with the Public Service Commission during March and subsequently resolved through a stipulated settlement in April. By using this expedited approach, a $170,000 rate increase was placed in effect sooner than in a general rate case.

In February 1993, the PUCO approved a settlement that Columbia Gas of Ohio reached with customers and interested parties extending existing base rates through 1994. This agreement will not affect the recovery of gas costs. In exchange for the moratorium, the settlement includes initiatives that will provide Columbia Gas of Ohio with a better opportunity to earn a fair return on its investment. The collaborative settlement has further improved Columbia Gas of Ohio's relationship with the PUCO, its customers and other critical interests, and allows all parties to reallocate resources to address emerging business issues such as Order 636 and Integrated Resource Planning.

Columbia Gas of Ohio Management Audit

During 1991, Columbia Gas of Ohio filed an application with the PUCO requesting approval for an increase in rates. A Joint Stipulation and Recommendation was approved by PUCO which, among other things, provided for an independent management audit. The management audit, which was concluded in November 1992, found that the company is well-managed, deals effectively with emerging issues and changes in the industry and is positioned to remain a viable and effective local distribution company. Most of the findings and conclusions endorsed the current business practices of the company. The remaining comments point to opportunities for improvement which management is in the process of implementing.

Revenue Stabilization

Historically, Distribution's rate structures have provided for the recovery of a substantial portion of fixed costs through the weather-sensitive portion of its sales rate. Since approximately 98% of Distribution's residential and commercial customer base is heat-sensitive, fluctuations in the recovery of costs result from weather variations. Distribution is pursuing an array of regulatory initiatives, including weather normalization adjustments, designed to mitigate these fluctuations and provide more stable cost recovery. Distribution is also attempting to mitigate the negative impact of regulatory lag through the adoption of forward-looking ratemaking concepts, incentive rates and certain cost deferrals. These measures, if adopted by the regulatory commissions, should result in more stable recovery levels.

FERC Order No. 636

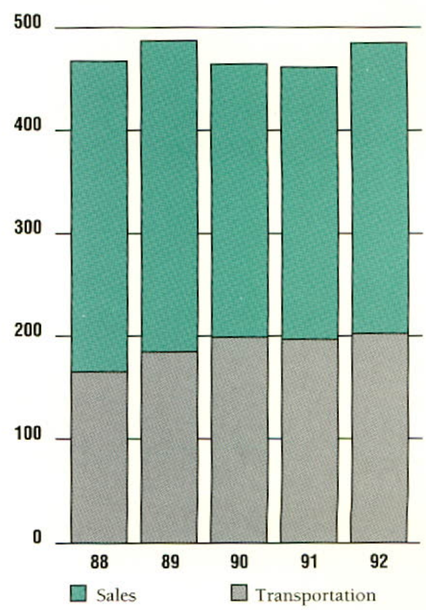
The move toward unbundling of pipeline services under Order 636 is creating a new operating environment for Distribution. The mandated straight-fixed variable rate design for pipelines places a greater premium on peak day capacity needed by heat-sensitive customers and will result in higher costs being incurred by Distribution. In addition, Distribution will assume full responsibility for acquiring and managing its own gas supplies. It is also apparent that Order 636 will require certain adjustments in state regulatory practices to recognize this additional gas management responsibility, Distribution's obligation to serve its customers and the end users increased access and utilization of natural gas transportation services. Order 636 also provides pipelines with an opportunity to pass through to distribution companies prudently incurred transition costs, including contract realignment and stranded costs stemming from Order 636. It is expected that local distribution companies (LDC) would recover any Order 636 costs over a three-to-five-year time period.

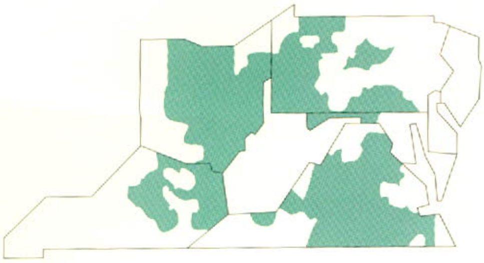
In February 1993, the Pennsylvania Public Utility Commission (PPUC) issued a proposed policy statement for comment regarding LDC recovery of Order 636 transition costs. The Pennsylvania Commission is considering the following positions:

- Pipeline deferred gas costs are recoverable through the gas cost recovery mechanism.
- Costs related to new facilities required by Order 636 restructuring may be considered purchased gas costs.
- Gas supply realignment costs and stranded costs may not be considered gas costs. Companies willing to absorb an equitable share of these costs would be permitted expedited recovery. Companies unwilling to absorb an equitable share would need to incorporate these costs in a base rate case filing.

Notwithstanding the proposed Pennsylvania policy statement and that state public service commissions have not yet developed final policies in these matters, management believes that Order 636 transition costs should be recoverable in Distribution rates.

DISTRIBUTION GAS THROUGHPUT
(in billion cubic feet)





■ Distribution Service Territory

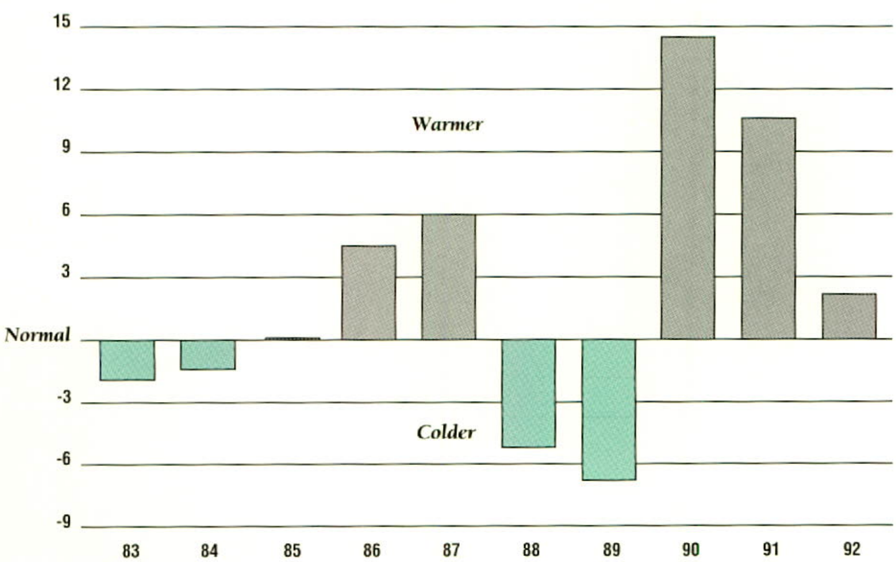
Gas Supply

Distribution continues to secure and provide its customers with competitively priced, reliable gas supplies. The restructuring and implementation of Distribution's gas supply portfolio, in response to Order 636, will require an aggressive approach toward optimizing available service levels. Some of these strategies will include utilizing appropriate pipeline capacity from the Southwest, using storage services, increasing purchases from local gas suppliers and acquiring and constructing pipeline facilities and interconnections that effectively enhance Distribution's market integration. This must be accomplished while achieving Distribution's two-part supply goal which includes maintaining competitive gas costs and providing reliable gas supplies.

Environmental Matters

Distribution is in the early stages of its self-assessment environmental program designed to ensure compliance with all state and federal environmental requirements. Management continues to anticipate recovery of investigation and remediation costs through normal rate processes.

Annual Percentage Variation from Normal Weather*



*Distribution Service Territory

Beginning in the mid-1800s, plants were constructed to manufacture low-cost gas for areas where natural gas was not generally available by heating certain combustibles in a low-oxygen atmosphere. The process created residues such as coal tar that were typically stored on site prior to being sold for commercial use. However, when the plants were closed or abandoned, this material was often buried on the plant site. As time passed, other uses were made of the plant sites and in some cases their identities as manufactured gas plants were lost. Certain predecessor companies of Distribution were, or may have been, involved with the ownership and/or the operation of some manufactured gas plants. At the present time, Distribution is investigating certain sites to determine the amount of remediation, if any, that may be required. Management anticipates the recovery of any remediation costs that may be incurred at any of these sites.

SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions

Effective January 1, 1991, the distribution subsidiaries adopted Statement of Financial Accounting Standards (SFAS) No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (OPEB). The present value of the postretirement benefit obligation to be paid to current and retired employees for all the distribution subsidiaries amounts to approximately $131.4 million as of December 31, 1992. Of this amount, $127.2 million is deferred as a regulatory asset pending anticipated recovery through rates in various jurisdictions. The Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board has recently issued guidelines establishing criteria for recording such a regulatory asset, including a requirement for collection of accrual basis expense in rates and recovery of the transition obligation within 20 years. These criteria will not necessarily be met by recovery methods adopted by public utility commissions regulating the distribution subsidiaries and could result in a writedown of some or all of this regulatory asset.

The distribution subsidiaries, as well as the Corporation's other operating companies, have implemented cost-containment measures

DISTRIBUTION OPERATING HIGHLIGHTS*

	1992	1991	1990	1989	1988
Capital Expenditures ($ in millions)	**99.7**	98.0	107.0	119.7	110.4
Throughput (Bcf)					
Sales					
Residential	**186.2**	178.4	173.5	201.5	195.0
Commercial	**81.8**	78.3	76.8	85.0	85.6
Industrial	**14.8**	10.8	16.6	16.4	25.0
Other	**0.2**	0.2	0.2	1.1	0.7
Total	**283.0**	267.7	267.1	304.0	306.3
Transportation	**203.7**	194.7	198.6	184.4	163.1
Throughput	**486.7**	462.4	465.7	488.4	469.4
Sources of Gas for Throughput (Bcf)					
Sources of Gas Sold					
Spot Market**	**169.9**	113.9	140.6	167.8	94.3
Producers	**57.1**	64.4	40.4	22.6	11.5
Pipelines	**84.0**	68.2	51.7	203.9	200.8
Storage withdrawals (injections)	**(10.7)**	11.4	38.1	(75.5)	–
Other	**(17.3)**	9.8	(3.7)	(14.8)	(0.3)
Total Sources of Gas Sold	**283.0**	267.7	267.1	304.0	306.3
Transportation received from pipelines and producers	**203.7**	194.7	198.6	184.4	163.1
Total Sources	**486.7**	462.4	465.7	488.4	469.4
Customers					
Residential	**1,711,946**	1,686,918	1,724,281	1,693,914	1,665,135
Commercial	**161,937**	160,378	165,144	161,864	157,440
Industrial	**2,358**	2,342	2,400	2,334	2,329
Other	**24**	24	20	26	29
Total	**1,876,265**	1,849,662	1,891,845	1,858,138	1,824,933
Degree Days	**5,507**	4,998	4,783	5,971	5,914

**Includes Columbia Gas of New York, Inc. through March 31, 1991.*
***Reflects volumes under purchase contracts of less than one year.*

designed to reduce their OPEB obligations. In addition to other measures, employees will be required to share a portion of their postretirement health benefit costs, and guidelines have been established redefining years of service requirements before an employee is eligible for retiree health benefits. Other cost-saving plans are being reviewed for consideration in an ongoing effort to effectively manage OPEB costs. The public service commissions in the distribution subsidiaries' operating territories continue to address these matters.

In Ohio, the staff of the PUCO has taken a position that would allow recovery of OPEB costs on an accrual basis. However, the method of recognizing the unfunded transition obligation at the time of adoption of SFAS No. 106 and the amortization period for the obligation is likely to be determined on a case-by-case basis. A final order from the PUCO regarding the outcome of this investigation is expected in the near future. The amount of the regulatory asset recorded for Columbia Gas of Ohio in the accompanying balance sheet totals \$77.4 million as of December 31, 1992.

In November 1992, the PPUC issued an order in response to a coalition of several utilities filing a joint petition requesting the deferral of OPEB costs. Basically, the PPUC indicated that the appropriate ratemaking treatment for OPEB costs is pay-as-you-go, which may, on a case-by-case basis, be modified to include rate recovery of funded amounts. The PPUC further stated that the appropriate level of transition costs to be allowed will also be decided on a case-by-case basis. At December 31, 1992, the carrying value of Columbia Gas of Pennsylvania's (CPA) regulatory asset was approximately \$31.6 million. A recent order filed by the PPUC for another utility's pending rate case allowed only pay-as-you-go treatment of OPEB costs until the PPUC could be shown that a viable cost-containment program has been effectuated. The PPUC also based its order on its determination that the utility did not adequately demonstrate how it plans to fund OPEB costs. The PPUC directed that company to record the difference between the level of OPEB expense and the pay-as-you-go method as a regulatory asset and agreed to address, in a separate rate proceeding, the recovery of OPEB accruals that are deemed prudently incurred. CPA has taken certain steps which it believes differentiates its facts and circumstances from this decision and will help ensure a favorable ruling from the PPUC on the recovery of these costs. CPA is committed to advance funding of the costs for retirees benefits in an irrevocable trust fund to the extent these costs are allowed in rates.

In January 1993, the Maryland Public Service Commission decided to defer its decision on Columbia Gas of Maryland's application to recover OPEB costs until a generic decision is made at a later date. In early 1993, an order was issued by the Virginia State Corporation Commission that provides for the full recovery of OPEB cost accruals, to the extent that they are funded, and the recovery of transition costs over a period of 40 years. Any timing difference between OPEB expense and amounts recovered may be deferred as a regulatory asset. However, as a result of the EITF guidelines, the Virginia distribution subsidiary expensed \$4.2 million in 1992. The Kentucky commission has indicated that it will address the recovery of OPEB costs on a case-by-case basis through rate filings.

Although proceedings in the applicable state jurisdictions are not final, based on currently available information, management believes rate recovery mechanisms will be adopted which permit continued regulatory asset treatment in accordance with recent EITF guidelines.

Integrated Resource Planning

Distribution is becoming involved in Integrated Resource Planning (IRP) that utilizes demand side options, coupled with traditional supply side alternatives, to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest overall cost. These demand side options can include activities that reduce or shift periods of high gas demand, improve load factors and increase gas use during low-demand periods. Pilot programs focusing on demand side management initiatives are currently being developed by Distribution and are anticipated to be filed for commission approval during 1993. Costs incurred associated with this activity are expected to be recovered through future rate filings.

During 1992, the Maryland Public Service Commission approved the implementation of two new demand side management programs on a pilot basis that deal with new construction and high-efficiency furnaces. Costs associated with these programs are being deferred as a regulatory asset and are being recovered through a special rate surcharge.

Volumes

Although 1992 was 2% warmer than normal, it averaged 10% colder than the prior year. After adjusting for the 1991 sale of Columbia Gas of New York, total throughput for 1992 increased approximately 30 Bcf. The colder weather, combined with the net addition of approximately 28,000 residential and commercial customers, was responsible for the 20 Bcf increase in sales. Increased transportation deliveries to power-generating facilities and customers using additional transportation services were the primary reasons for the transportation improvement of 10 Bcf.

Throughput for 1991 increased 5 Bcf from 1990, after adjusting for the sale of Columbia Gas of New York. Weather that was 4% colder than 1990 and the net addition of approximately 27,000 new residential and commercial customers were the primary reasons for the increase. Also contributing to the improvement was higher transportation deliveries, primarily to power-generating facilities in Virginia and a refinery operating in Kentucky.

Net Revenues

Colder weather in 1992 was the primary cause of the increase in Distribution's net revenues to $696.5 million, an increase of $51 million. The full-year effect of 1991 rate settlements in all of Distribution's operating areas and colder 1992 weather primarily caused the $44.2 million increase in net sales revenues from $584.7 million in 1991. The improvement in net sales revenues was partially offset by the impact of the sale of the New York subsidiary in 1991. The increased transportation volumes during 1992 resulted in higher net transportation revenues of $6.8 million.

The combined effect of general rate settlements and colder weather in 1991 increased Distribution's net revenues to $645.5 million, $23.1 million higher than in 1990.

Operating Income

Increased net revenues, partially offset by rising operating expenses, resulted in an operating income increase of $22.8 million over 1991 to $137.7 million. Higher labor and benefits costs contributed to the increased level of operating expenses during 1992. Regulatory lag continues to affect operating income since only a portion of current increased costs are being recovered through rates.

In 1991, the rise in net revenues was partially offset by higher operating expenses, primarily labor and benefits expense. Operating income for 1991 increased to $114.9 million, up $18.2 million over 1990.

OTHER ENERGY

Cogeneration

Cogeneration is a highly efficient process which simultaneously produces electricity and useful thermal energy from a single fuel. This continues to be a key growth area for natural gas. The Columbia Gas System is involved in several cogeneration projects through TriStar Ventures Corporation (TriStar), a wholly-owned subsidiary. During 1992, two major cogeneration projects were completed by TriStar and its partners. A 117-megawatt facility in Pedricktown, N.J., commenced operations in April. The facility provides electricity to Atlantic City Electric Company in southern New Jersey and steam and electricity to a BF Goodrich chemical plant. A 50-megawatt plant in Binghamton, N.Y., began commercial service in November. It produces electricity for New York State Electric and Gas Corporation and sells recovered heat and electric power to the Anitec Image Division of International Paper Company. Natural gas is delivered to these facilities by Columbia Transmission. During 1992, these projects generated \$3.3 million of income before interest and income taxes. The transmission subsidiaries of the Corporation benefit from increased throughput that the projects generate while the oil and gas segment has increased sales opportunities.

TriStar and its partners have other projects in various stages of development. In particular, construction began during 1992 on a 47-megawatt plant near Vineland, N.J. This facility is scheduled to begin operations in mid-1994, providing a municipal electric utility in Vineland with electricity and Progresso Quality Foods with thermal energy. The construction of a 56-megawatt plant in the Washington, D.C., area has been delayed pending regulatory review and approval. In 1992, TriStar recorded a \$1.8 million reserve for certain costs caused by this delay. However, if further delays in the project are encountered, additional costs may be incurred. It is anticipated that construction of this project will begin in the first half of 1993 with commercial operation in 1995.

Propane

During 1992, over 63 million gallons of propane were sold to approximately 66,000 customers by Columbia Propane Corporation and Commonwealth Propane, Inc. The propane companies' principal operating areas include parts of Virginia, Ohio, Maryland and Pennsylvania. The propane companies have been focusing on increasing sales to the higher margin segment of their markets through innovative programs.

Coal

The approximately 550 million tons of proved coal reserves owned by the Corporation are among the largest in the Appalachian area. Approximately 50% of these reserves, much of which contain less than one percent sulfur, are leased to other parties for development. Royalty revenues from these leases are anticipated to continue to increase during 1993.

Net Revenues

The mix of propane sales over the past two years has been changing with sales increasing to residential customers and decreasing to wholesale and industrial customers. This has caused total sales volumes to decrease but net sales revenues to increase, since the additional residential sales provide higher margins than either wholesale or industrial sales. This change led to net sales revenues of $27.3 million in 1992, an increase of $0.7 million over 1991, and to $26.6 million in 1991, an increase of $2.3 million compared to the 1990 level.

Other Energy Operating Highlights

	1992	1991	1990	1989	1988
Capital Expenditures ($ in millions)	**15.0**	10.2	14.1	16.4	23.8
Propane					
Gallons sold (millions)	**63.3**	70.5	74.4	75.2	73.3
Customers	**65,899**	64,618	63,546	62,707	50,016
Coal Reserves (million tons)	**550**	550	550	550	650

Statements of Operating Income from Other Energy Operations (Unaudited)

Year Ended December 31 (in millions)	**1992**	1991	1990
Net Revenues			
Sales revenues	**$133.5**	$121.0	$110.1
Less: Products purchased	**106.2**	94.4	85.8
Net Sales Revenues	**27.3**	26.6	24.3
Other revenues	**70.3**	75.5	76.9
Net Revenues	**97.6**	102.1	101.2
Operating Expenses			
Operation and maintenance	**80.8**	87.6	87.4
Depreciation and depletion	**4.9**	4.0	3.6
Other taxes	**5.1**	5.6	4.7
Total Operating Expenses	**90.8**	97.2	95.7
Operating Income	**$ 6.8**	$ 4.9	$ 5.5

A decline in 1992 revenues from services provided to affiliates more than offset increased coal royalties and resulted in a reduction in other revenues of $5.2 million, to $70.3 million, from the prior year. Other revenues in 1991 of $75.5 million were $1.4 million lower than the year earlier primarily due to a one-time favorable adjustment recorded in 1990 for prior period royalty payments.

Operating Income

The net revenue decline of $4.5 million was more than offset by a decrease of $6.4 million in operating expenses primarily reflecting a decrease in labor and benefits costs caused by a reduced number of employees and a one-time adjustment in 1991 for employee severance costs. The drop in operating expenses, partially offset by the decline in net revenues, resulted in operating income of $6.8 million compared to $4.9 million in 1991.

A small improvement in net revenues was more than offset by increases in operating expenses which decreased operating income in 1991 by $0.6 million to $4.9 million from the 1990 level.

CONSOLIDATED REVIEW

Net Income (Loss)

For 1992 the Corporation recorded net income of $51.2 million, or $1.01 per share, compared to a net loss of $694.4 million, or $13.74 per share last year. Included in the results for both years were several unusual items that are discussed below. Absent these unusual items net income for 1992 would have been $98.7 million, compared to $80.8 million for the same period in 1991. The current period increase primarily reflects the beneficial effect of improved rates for the distribution and transmission subsidiaries together with increased throughput due in part to colder weather. The unusual items and their after-tax impact on net income are listed below.

1992 ($ in millions)

- 137.0 improvement for bankruptcy-related issues largely due to not recording interest costs on prepetition obligations partially offset by related expenses,
- (83.4) writedown in the carrying value of oil and gas properties due to depressed energy prices in the first quarter,
- (41.0) reserve addition for environmental costs,
- (39.7) charge by Columbia LNG resulting from the discontinuance of SFAS No. 71,
- (24.2) writedown of previously capitalized gas costs by Columbia Transmission due to the eventual elimination of its merchant function,
- 13.1 improvement for gas inventory charges collected from customers, and
- (9.3) reserve adjustment for a proposed producer settlement.

1991 ($ in millions)

- (870.7) expense associated with a provision for gas supply charges,
- 100.4 improvement for the net effect of accounting changes,
- 43.8 improvement for bankruptcy items primarily for not accruing interest expense on prepetition debt,
- (24.0) writedowns in the carrying value of the Canadian oil and gas properties,
- (17.4) expense for reserve additions for environmental costs,
- (9.6) writedown in cogeneration project investments,
- 9.2 gain on sale of New York distribution subsidiary, and
- (6.9) reserve adjustment for a proposed producer settlement.

A pre-tax writedown in the first quarter of 1992 in the carrying value of U.S. oil and gas properties of $126.4 million as compared to $36.4 million in writedowns of the Canadian properties in 1991 was the major cause of the oil and gas segment reporting an operating loss of $101.2 million for 1992 and an operating loss of $4.5 million in 1991. Also contributing to the decline was higher operating expenses partially offset by losses incurred by the Canadian oil and gas operation in 1991 which was sold effective December 31, 1991.

The transmission segment had operating income of $129.9 million for 1992 compared to a loss of $1,192.2 million in the prior year. The major cause of the increase was the 1991 provision for gas supply charges of $1,319.2 million. The increase in net revenues due to higher throughput and rate design changes, offset by reserve additions for future environmental costs and a writedown of previously capitalized gas costs, also contributed to the improved operating income.

Colder weather in 1992, combined with favorable rate settlements in each of the distribution operating areas, increased the distribution segment operating income $22.8 million over 1991 to $137.7 million. As a result of the colder weather combined with the net addition of 28,000 residential and commercial customers, throughput increased 24 Bcf, or 5%. Current recovery of increased expenses continues to be hampered by regulatory lag.

For other energy operations, lower operation and maintenance costs, partially offset by a decline in net revenues, resulted in an operating income of $6.8 million, an increase of $1.9 million.

Due primarily to Columbia Transmission's after-tax charges of $870.7 million recorded during 1991 related to above-market producer contracts, the Corporation recorded an after-tax loss of $694.4 million, or $13.74 per share compared to net income of $104.7 million, or $2.21 per share in 1990. Also contributing to the loss was the effect of 1991 writedowns for the Canadian properties and lower oil and gas prices. Partially offsetting these decreases was the adoption of SFAS No. 106 and SFAS No. 96, which resulted in a net after-tax benefit to the Corporation of $100.4 million. In addition, Distribution results improved due to weather that was 4% colder than 1990 but still 11% warmer than normal.

Changes in other income (deductions) also affecting income are discussed on page 38.

Revenues

Increased throughput from colder weather during 1992 that provided higher sales volumes combined with the full-year effect of higher distribution rates, Columbia Transmission's new rate design and a more competitive sales rate increased operating revenues to $2,922 million, an increase of $345.2 million over 1991.

Operating revenues for 1991 increased $218.9 million to $2,576.8 million. With weather colder than in 1990 and higher average rates in effect for 1991, gas sales revenue increased $153.7 million. Also increasing revenues in 1991 compared to 1990 was additional recovery of upstream pipeline supplier take-or-pay costs, the majority of which were offset by associated gas purchase expense. Gas transportation revenues increased $51.8 million over 1990 due in part to additional volumes being transported. Other revenues increased $13.4 million over the same period.

Expenses

Volumes purchased during 1992 to meet higher gas sales requirements increased products purchased to $1,236.9 million from $1,056.5 million last year. In 1991, increased volumes purchased for resale brought total 1991 products purchased expense to $1,056.5 million, an increase of $209.7 million over 1990.

In anticipation of Columbia Transmission providing only a minimal merchant function after November 1, 1993, a $38.6 million provision for gas supply charges was recorded reflecting a writedown of certain capitalized gas costs in excess of amounts to be amortized in 1993. In 1991 Columbia Transmission recorded a $1,319.2 million provision for gas supply charges to reflect the rejection of above-market producer contracts, related gas supply management costs and the impact of contract rejection on gas costs previously capitalized.

The recording by Columbia Transmission of higher environmental expenses and higher labor and benefits expense were the primary reasons for the $111.3 million increase in operation and maintenance expense to $921.5 million in 1992. Also contributing to this increase are additional expenses associated with certain producer settlements. In 1991, a reduction in costs associated with Columbia Transmission's efforts to renegotiate certain producer contracts and settle other producer disputes decreased operation and maintenance expense from 1990's level by $11.8 million. Partially offsetting this decrease was higher labor and benefits expense combined with higher environmental expense for estimated future costs.

A writedown in the carrying value of U.S. oil and gas properties during 1992 due to depressed first-quarter energy prices, partially offset by the sale of the Canadian oil and gas subsidiary in 1991, resulted in an increase in depreciation and depletion expense of $83.1 million to $368.1 million. Due primarily to an increase in 1991 over 1990 of $13.8 million in writedowns of the carrying value of the Canadian oil and gas property and increased investment in plant, depreciation and depletion expense increased $36.2 million in 1991 over 1990.

Other Income (Deductions)

As a result of the bankruptcy filing, the Corporation discontinued recording interest expense on prepetition debt obligations on August 1, 1991, which, if recorded, would have increased interest expense by $224.9 million in 1992 and $85.6 million in 1991. This action, when comparing the two years, together with lower other interest expense, was the reason for the decline in interest expense and related charges of $123.7 million. Several items primarily caused the $11.9 million decline in interest income and other, net. These items included a lower interest income accrual of $3.8 million, a $1.8 million writedown of coal facilities and a $1.8 million writedown for cogeneration projects. Also contributing to this decrease was a $17.9 million gain on the sale of Columbia Gas of New York, Inc. and a $2.9 million gain on the sale of the Canadian properties in 1991 that was largely offset by a $14.5 million writedown for certain cogeneration investments. Although reorganization items, net remained relatively unchanged from the prior year, an increase in interest income of $22.4 million from the accumulation of excess cash was offset by an increase of $16.3 million in professional fees.

In 1990, a favorable court ruling provided a $17.9 million benefit, and a settlement on the value of a property dispute increased interest income and other, net $47.9 million. These items together with the writedown for certain cogeneration investments in 1991 contributed to the $37.9 million decrease in interest income and other, net for 1991 compared to the year earlier. Mitigating this decrease was the effect during 1991 of the Corporation recording the gain on the sale of Columbia Gas of New York, Inc. together with higher pipeline partnership income and other interest income. Primarily as a result of not accruing $85.6 million in interest expense for prepetition debt securities by the Corporation since August 1, 1991, interest expense and related charges declined $32.4 million compared to 1990. Expenses incurred by the Corporation and Columbia Transmission during 1991 related to the Bankruptcy filings resulted in $14.4 million for reorganization items, net. Of this amount, $18.9 million was attributable to professional fees and related expenses, partially offset by $4.5 million of interest income on excess cash accumulated as a result of the bankruptcy filing.

Income Taxes

Income taxes, as detailed in Note 5 of Notes to Consolidated Financial Statements, increased $481.5 million, principally due to the Corporation having pre-tax book income in 1992 compared to an operating loss in 1991.

Liquidity and Capital Resources

Cash from Operations

Due primarily to colder weather in 1992 than experienced in the prior year and the suspension of interest payments on August 1, 1991, resulting from the bankruptcy filing, net cash from operations increased $233.8 million to $765.4 million compared to $531.6 million last year. Higher throughput in the current year from colder weather, increased receipts due to implementing a new rate design for the transmission subsidiaries and higher Distribution rates in effect were the primary reasons for the $300.5 million increase in cash received from customers. The suspension of interest payments on prepetition debt obligations led to the $100.4 million decrease in interest paid. Partially offsetting these increases was the receipt in 1991 of payment for a settlement of a property issue which caused other operating cash receipts to decline $48 million. Also, higher

Statements of Common Stock Prices and Dividends

Quarter Ended	High	Low	Close	Quarterly Dividends Paid
	Market Price			
	$	$	$	¢
1992				
December 31	**23⅞**	**18⅝**	**19⅛**	**–**
September 30	**20**	**16⅜**	**20**	**–**
June 30	**17⅝**	**14**	**17**	**–**
March 31	**19¼**	**16⅛**	**17¾**	**–**
1991				
December 31	19½	16	17¼	–
September 30	19¾	12⅞	18⅞	–
June 30	45¾	16½	19⅛	58
March 31	47½	42⅜	44⅛	58

income taxes due to timing differences between periods and increased property tax assessments caused income taxes paid and other tax payments to increase $40.6 million and $31.5 million, respectively.

Largely due to reductions in amounts paid to suppliers and lower interest and other taxes paid, partially offset by lower cash received from customers, net cash from operations in 1991 was $531.6 million, up $111.5 million from 1990. Lower cash paid to suppliers of $307.1 million was made possible by the rejection of Columbia Transmission's above-market gas purchase contracts. In addition, cash payments made in 1990 for the purchase of natural gas to meet customer demand from the cold 1989 temperatures also caused 1991 cash paid to suppliers to decrease from 1990. As a result of the Chapter 11 filing, the suspension of payments for debt obligations on August 1, 1991, combined with the effect of a prior period payment for the settlement of a tax issue, interest and other taxes paid were reduced from the 1990 levels. Mitigating the higher level of cash expenditures in 1990 were the effects of an unusually cold December 1989 on cash received from customers in 1990. Higher taxable income and the timing of certain federal income tax payments increased income taxes paid in 1991 by $21.4 million.

The Corporation maintains a debtor-in-possession facility (DIP Facility) for up to $200 million, including the availability of letters of credit of up to $50 million. The DIP Facility was reduced by the Corporation from $275 million to the current level on July 10, 1992. The DIP Facility is used in conjunction with internally-generated funds for general corporate purposes and to provide financing for subsidiaries not involved in the bankruptcy proceedings.

During 1992, maximum borrowings under the DIP Facility were $136 million. The Corporation was in a cash surplus position for the majority of the year and expects to remain in a cash surplus position during most of 1993. As of January 31, 1993, the Corporation and its subsidiaries, excluding Columbia Transmission, had excess cash of $77.5 million, which was invested in money market instruments. The Corporation will likely request an extension of its DIP Facility past the current September 1993 expiration date.

The liquidity needs of Columbia Transmission are being satisfied by its internally-generated funds. Columbia Transmission also maintains a DIP facility solely for the issuance of letters of credit for up to $25 million. Columbia Transmission has extended its DIP facility to December 31, 1994, to allow for letters of credit with terms for the full calendar year of 1994. As of January 31, 1993, Columbia Transmission had $831.3 million invested in money market instruments through a wholly-owned subsidiary, Columbia Transmission Investment Corporation.

Capital expenditures for 1992 were $300 million, a decrease of $82 million from 1991. The Corporation's subsidiaries reduced capital expenditures to the extent possible, consistent with the need to maintain safe and efficient operating facilities, the need to meet new service and tariff obligations, drilling commitments, and the need to preserve going concern values.

For 1993, capital expenditures, which are under the same limitations as the 1992 program, are expected to increase to $391 million of which $31 million is attributable to carryovers from 1992. As shown in the table below, expenditures by Columbia Transmission are expected to increase from $106 million in 1992 to $138 million in 1993 while other transmission expenditures increase to $35 million. Distribution expenditures are expected to increase by $25 million to $125 million. Oil and gas expenditures in 1993 are expected to be $69 million, $2 million lower than the 1992 level.

CAPITAL EXPENDITURES

(in millions)	1993	1992
Columbia Transmission	$138	$106
Other Transmission	35	8
Distribution	125	100
Oil and Gas	69	71
Other Energy	24	15
Total	$391	$300

COMPARATIVE GAS OPERATIONS DATA

THE COLUMBIA GAS SYSTEM, INC. AND SUBSIDIARIES

	1992	1991	1990	1989	1988
Sales and Transportation Revenues ($ in millions)					
Residential	**1,089.1**	1,019.3	943.9	1,140.6	1,157.7
Commercial	**426.2**	402.2	369.9	450.7	470.1
Industrial	**67.5**	51.5	64.0	82.2	118.4
Wholesale	**569.4**	373.7	321.0	835.2	919.1
Other	**130.1**	108.2	102.4	81.6	40.6
Transportation	**438.6**	425.0	373.2	512.3	370.3
Total Sales and Transportation Revenues	**2,720.9**	2,379.9	2,174.4	3,102.6	3,076.2
Sales (billion cu. ft.)					
Residential	**186.3**	178.5	173.5	201.5	195.5
Commercial	**81.8**	78.4	76.8	85.0	85.6
Industrial	**14.8**	10.8	16.6	16.8	26.9
Wholesale	**148.3**	93.6	82.7	246.8	220.8
Other	**68.3**	65.7	52.3	46.1	22.5
Total Sales	**499.5**	427.0	401.9	596.2	551.3
Transportation volumes	**1,349.1**	1,269.8	1,175.0	1,051.5	779.4
Total Throughput	**1,848.6**	1,696.8	1,576.9	1,647.7	1,330.7
Sources of Gas Sold (billion cu. ft.)					
Total gas purchased	**433.0**	370.6	453.3	449.4	517.5
Total gas produced	**69.2**	76.3	75.3	77.9	74.6
Exchange gas–net	**17.5**	(15.3)	21.1	(15.0)	5.8
Gas withdrawn from (delivered to) storage	**14.5**	24.7	(137.5)	109.0	(0.2)
Company use and other	**(34.7)**	(29.3)	(10.3)	(25.1)	(46.4)
Total Sources of Gas Sold	**499.5**	427.0	401.9	596.2	551.3
Customers at Year End					
Residential	**1,711,946**	1,687,631	1,724,281	1,693,914	1,666,013
Commercial	**161,937**	160,420	165,144	161,864	157,475
Industrial	**2,358**	2,345	2,400	2,334	2,341
Wholesale	**78**	80	81	78	79
Other	**217**	200	142	127	96
Total Customers at Year End	**1,876,536**	1,850,676	1,892,048	1,858,317	1,826,004
Average Usage Per Customer (thousand cu. ft.)					
Residential	**108.8**	105.8	100.6	119.0	117.4
Commercial	**505.1**	488.7	465.1	524.9	543.6
Degree Days for Retail Operations	**5,507**	4,998	4,783	5,971	5,914
% Colder (warmer) than normal	**(2.1)**	(10.6)	(14.5)	6.8	5.2

($ in millions except per share amounts)	**1992***	1991*	1990	1989	1988
Income Statement Data ($)					
Total operating revenues	**2,922.0**	2,576.8	2,357.9	3,204.4	3,168.2
Products purchased	**1,236.9**	1,056.5	846.8	1,669.0	1,822.3
Earnings (Loss) on common stock before extraordinary item and accounting changes	**90.9**	(794.8)	104.7	145.8	111.1
Earnings (Loss) on common stock	**51.2**	(694.4)	104.7	145.8	111.1
Per Share Data					
Earnings (Loss) per common share ($):					
Before extraordinary item and accounting changes	**1.79**	(15.72)	2.21	3.21	2.46
Earnings (Loss) on common stock	**1.01**	(13.74)	2.21	3.21	2.46
Dividends:					
Per share ($)	**–**	1.16	2.20	2.00	2.295
Payout ratio (%)	**N/M**	N/M	99.5	62.3	93.3
Average common shares outstanding (000)	**50,559**	50,537	47,316	45,494	45,190
Balance Sheet Data ($)					
Capitalization excluding liabilities subject to Chapter 11 (including short-term debt and current maturities**):					
Common stock equity	**1,075.1**	1,006.9	1,757.8	1,620.3	1,552.6
Long-term debt	**5.4**	6.1	1,428.7	1,196.0	1,038.4
Short-term debt and current maturities	**1.4**	138.9	770.7	681.4	749.8
Total	**1,081.9**	1,151.9	3,957.2	3,497.7	3,340.8
Total assets	**6,530.9**	6,332.2	6,196.3	5,878.4	5,641.0
Other Financial Data					
Capitalization ratio (%) (including short-term debt and current maturities**):					
Common stock equity	**99.4**	87.4	44.4	46.3	46.5
Debt	**0.6**	12.6	55.6	53.7	53.5
Capital expenditures ($)	**299.7**	381.9	629.6	473.5	307.9
Net cash from operations ($)	**765.4**	531.6	420.1	400.5	429.4
Book value per common share ($)	**21.26**	19.92	34.83	35.50	34.18
Return on average common equity before extraordinary charges (%)	**8.7**	N/M	6.2	9.2	7.2

N/M—Not meaningful

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financial Statements.

**Prior to its Chapter 11 filing, the Corporation made extensive use of variable rate debt since the associated cost was normally less than senior long-term debt. Inclusion of the short-term debt in years prior to 1991 makes those historical ratios more meaningful.

Management's Statement of Responsibility for Financial Statements

The accompanying consolidated financial statements and related notes have been prepared by the Corporation based on generally accepted accounting principles, and are considered by management to present fairly the Corporation's financial position and results of operations. The integrity and objectivity of the data in these financial statements, including estimates and judgments relating to matters not concluded by year end, are the responsibility of management as is all other information included in the Annual Report, unless otherwise indicated.

To meet its responsibilities with respect to financial information, management maintains an accounting system and related controls to reasonably assure the integrity of financial records and the protection of assets. The effectiveness of this system is enhanced by the selection and training of qualified personnel, an organizational structure that provides an appropriate division of responsibility, a strong budgetary system of control, and a comprehensive program of internal audits designed, in total, to provide reasonable assurance regarding the adequacy of internal controls and implementation of company policies and procedures. The internal audit staff is under the direction of the Vice President and General Auditor who reports directly to the Chairman of the Board and has unrestricted access to the audit committee of the Board of Directors.

The audit committee assists the Board of Directors in its oversight role and is composed of seven directors who are not officers or employees of the Corporation. The audit committee meets periodically with the Vice President and General Auditor to review the results of internal audits and to monitor the discharge of his responsibilities. The audit committee also meets periodically with the Corporation's independent public accountants, who have free access to the audit committee to discuss internal accounting controls, auditing and financial reporting matters.

Report of Independent Public Accountants

To the Shareholders of The Columbia Gas System, Inc.:

We have audited the accompanying consolidated balance sheets of The Columbia Gas System, Inc. (a Delaware corporation, the "Corporation") and subsidiaries as of December 31, 1992 and 1991, and the related statements of consolidated income, common stock equity and cash flows for each of the three years in the period ended December 31, 1992. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the 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 financial position of the Corporation and subsidiaries as of December 31, 1992 and 1991, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1992, in conformity with generally accepted accounting principles.

On July 31, 1991, the Corporation and Columbia Gas Transmission Corporation ("Columbia Transmission"), a wholly-owned subsidiary, filed separate petitions seeking protection under Chapter 11 of the Federal Bankruptcy Code. Note 2 discusses, among other matters, uncertainties associated with the Chapter 11 proceedings, including the status of the Corporation's loans to Columbia Transmission, certain prepetition intercompany asset transfers and the measurement of certain liabilities. Further, as discussed in Note 12D, subsequent to the Corporation's June 1991 announcement of a probable charge to earnings and suspension of the dividend, purported class action and other complaints have been filed against the Corporation generally alleging violations of certain securities laws. The accompanying financial statements do not reflect any liability associated with these complaints as the Corporation believes it has meritorious defenses to these actions; however, the ultimate outcome is uncertain. As a result of these matters, the Corporation may take, or be required to take, actions which may cause assets to be realized or liabilities to be liquidated for amounts other than those reflected in the financial statements. These factors create substantial doubt about the Corporation's ability to continue as a going concern. The accompanying financial statements have been prepared assuming that the Corporation and Columbia Transmission will continue as going concerns which contemplates the realization of assets and payment of liabilities in the ordinary course of business. The appropriateness of the Corporation continuing to present financial statements on a going concern basis is dependent upon, among other items, the terms of the ultimate plan of reorganization and the ability to generate sufficient cash from operations and financing sources to meet obligations.

As discussed in Note 4, effective January 1, 1991, the Corporation changed its method of accounting for income taxes and post-retirement benefits other than pensions pursuant to standards promulgated by the Financial Accounting Standards Board.

Arthur Andersen & Co.

New York, New York
February 10, 1993

THE COLUMBIA GAS SYSTEM, INC. AND SUBSIDIARIES

Year Ended December 31 (in millions except per share amounts)	1992*	1991*	1990
Operating Revenues			
Gas sales	**$2,282.3**	$1,954.9	$1,801.2
Transportation	**438.6**	425.0	373.2
Other	**201.1**	196.9	183.5
Total Operating Revenues	**2,922.0**	2,576.8	2,357.9
Operating Expenses			
Products purchased	**1,236.9**	1,056.5	846.8
Provision for gas supply charges	**38.6**	1,319.2	–
Operation	**764.4**	689.4	714.1
Maintenance	**157.1**	120.8	107.9
Depreciation and depletion	**368.1**	285.0	248.8
Other taxes	**194.0**	192.3	178.2
Total Operating Expenses	**2,759.1**	3,663.2	2,095.8
Operating Income (Loss)	**162.9**	(1,086.4)	262.1
Other Income (Deductions)			
Interest income and other, net (Note 13)	**20.5**	32.4	70.3
Interest expense and related charges** (Note 14)	**(13.7)**	(137.4)	(169.8)
Reorganization items, net (Note 2)	**(8.3)**	(14.4)	–
Total Other Income (Deductions)	**(1.5)**	(119.4)	(99.5)
Income (Loss) before Income Taxes, Extraordinary Item and Cumulative Effect of Accounting Changes	**161.4**	(1,205.8)	162.6
Income taxes (Note 5)	**70.5**	(411.0)	57.9
Income (Loss) before Extraordinary Item and Cumulative Effect of Accounting Changes	**90.9**	(794.8)	104.7
Extraordinary item (Note 12G)	**(39.7)**	–	–
Cumulative effect of change in accounting for income taxes (Note 4B)	–	170.0	–
Cumulative effect of change in accounting for postretirement benefits (Note 4A)	–	(69.6)	–
Net Income (Loss)	**$ 51.2**	$ (694.4)	$ 104.7
Earnings (Loss) Per Share of Common Stock (based on average shares outstanding)			
Before extraordinary item and accounting changes	**$ 1.79**	$ (15.72)	$ 2.21
Extraordinary item	**(0.78)**	–	–
Change in accounting for income taxes	**–**	3.36	–
Change in accounting for postretirement benefits	**–**	(1.38)	–
Earnings (Loss) on Common Stock	**$ 1.01**	$ (13.74)	$ 2.21
Dividends Per Share of Common Stock	**–**	$ 1.16	$ 2.20
Average Common Shares Outstanding (thousands)	**50,559**	50,537	47,316

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financial Statements.

**Due to the bankruptcy filing, interest expense of $224.9 million and $85.6 million has not been recorded for 1992 and 1991, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Assets as of December 31 (in millions)	**1992***	1991*
Property, Plant and Equipment		
Gas utility and other plant, at original cost	**$5,758.6**	$5,575.0
Accumulated depreciation and depletion	**(2,916.6)**	(2,794.8)
	2,842.0	2,780.2
Oil and gas producing properties, full cost method	**1,190.4**	1,167.6
Accumulated depletion	**(602.1)**	(441.3)
	588.3	726.3
Net Property, Plant and Equipment	**3,430.3**	3,506.5
Investments and Other Assets		
Gas inventory–noncurrent	**346.3**	375.8
Gas supply prepayments	**20.0**	85.8
Accounts receivable–noncurrent	**218.0**	94.1
Unconsolidated affiliates	**66.7**	52.4
Investment in Columbia LNG Corporation	**51.9**	92.5
Other	**31.2**	32.2
Total Investments and Other Assets	**734.1**	732.8
Current Assets		
Cash and temporary cash investments	**820.6**	408.3
Accounts receivable		
Customers (less allowance for doubtful accounts of $11.8 and $9.7, respectively)	**504.6**	535.3
Other	**241.9**	326.0
Gas inventory	**330.7**	372.4
Other inventories–at average cost	**47.4**	50.7
Prepayments	**127.0**	130.5
Other	**56.8**	1.6
Total Current Assets	**2,129.0**	1,824.8
Deferred Charges	**237.5**	268.1
Total Assets	**$6,530.9**	$6,332.2

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financial Statements.

**The Corporation has 10,000,000 shares of preferred stock, $50 par value, authorized but unissued.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Capitalization and Liabilities as of December 31 (in millions)	**1992***	1991*
Common Stock Equity		
Common stock, par value $10 per share–outstanding 50,559,225 shares	**$ 505.6**	$ 505.6
Additional paid in capital	**601.8**	601.8
Retained earnings	**37.7**	(13.5)
Unearned employee compensation (Note 9)	**(70.0)**	(87.0)
Total Common Stock Equity	**1,075.1**	1,006.9
Long-Term Debt	**5.4**	6.1
Total Capitalization**	**1,080.5**	1,013.0
Current Liabilities		
Debtor-in-possession financing (Note 10)	**–**	136.0
Debt obligations	**1.4**	2.9
Accounts and drafts payable	**231.7**	188.4
Accrued taxes	**144.1**	135.8
Accrued interest	**15.6**	16.7
Estimated rate refunds	**182.3**	67.9
Deferred income taxes	**19.7**	21.5
Other	**267.8**	257.6
Total Current Liabilities	**862.6**	826.8
Liabilities Subject to Chapter 11 Proceedings (Note 2)	**3,967.2**	3,903.5
Other Liabilities and Deferred Credits		
Income taxes–noncurrent	**190.3**	217.4
Investment tax credits	**40.8**	42.2
Postretirement benefits other than pensions	**233.4**	230.2
Other	**156.1**	99.1
Total Other Liabilities and Deferred Credits	**620.6**	588.9
Commitments and Contingencies (Notes 2, 3, 4, 9 and 12)	–	–
Total Capitalization and Liabilities	**$6,530.9**	$6,332.2

THE COLUMBIA GAS SYSTEM, INC. AND SUBSIDIARIES

Year Ended December 31 (in millions)	1992*	1991*	1990
Operations			
Cash received from customers	**$2,880.1**	$2,579.6	$2,829.8
Other operating cash receipts	**125.6**	173.6	161.2
Cash paid to suppliers	**(1,027.3)**	(1,012.1)	(1,319.2)
Interest paid	**(1.4)**	(101.8)	(172.5)
Income taxes paid	**(120.4)**	(79.8)	(58.4)
Other tax payments	**(196.0)**	(164.5)	(197.9)
Cash paid to employees and for other employee benefits	**(479.1)**	(464.2)	(445.2)
Other operating cash payments	**(407.0)**	(396.0)	(377.7)
Reorganization items–net	**(9.1)**	(3.2)	–
Net Cash From Operations	**765.4**	531.6	420.1
Investment Activities			
Capital expenditures**	**(294.5)**	(376.5)	(600.1)
Replacement of base gas inventory	–	–	(156.9)
Gas supply prepayments–net	**3.2**	(36.3)	(17.5)
Other investments–net	**72.2**	89.3	8.1
Net Investment Activities	**(219.1)**	(323.5)	(766.4)
Financing Activities			
Dividends paid	–	(55.7)	(103.9)
Issuance of revolving credit agreement	–	20.0	145.0
Retirement of long-term debt and preferred stock	**(2.4)**	(20.3)	(71.7)
Issuance of common stock	–	3.4	225.3
Issuance of long-term debt	–	–	204.5
Increase (decrease) in short-term debt and other financing activities	**4.4**	108.9	(59.0)
Net debtor-in-possession financing	**(136.0)**	136.0	–
Net Financing Activities	**(134.0)**	192.3	340.2
Increase (decrease) in cash and temporary cash investments	**412.3**	400.4	(6.1)
Cash and temporary cash investments at beginning of year	**408.3**	7.9	14.0
Cash and temporary cash investments at end of year***	**$ 820.6**	$ 408.3	$ 7.9
Net Income Reconciliation:			
Net income (loss)	**$ 51.2**	$ (694.4)	$ 104.7
Items not requiring (providing) cash:			
Depreciation and depletion	**368.1**	285.0	248.8
Deferred income taxes	**(30.3)**	(525.7)	(14.6)
Amortization of prepayments for producer contract modifications	**23.9**	54.5	72.3
Provision for gas supply charges	**38.6**	1,319.2	–
Extraordinary item	**39.7**	–	–
Change in accounting for income taxes	–	(170.0)	–
Change in accounting for postretirement benefits	–	69.6	–
Gain on sale of interests in subsidiaries	–	(21.4)	–
Other–net	**182.7**	39.6	31.3
Net change in working capital (Note 15)	**91.5**	175.2	(22.4)
Net Cash From Operations	**$ 765.4**	$ 531.6	$ 420.1

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financial Statements.

**Includes amounts transferred from interest paid, cash paid to employees and for other employee benefits and other operating cash payments.

***The Corporation considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Statements of Consolidated Common Stock Equity

(In millions except for share amounts)	Common Stock* Shares Outstanding (000)	Common Stock* Par Value	Additional Paid In Capital	Retained Earnings	Unearned Employee Compensation	Accumulated Foreign Currency Translation Adjustment
Balance at December 31, 1989	45,643	$456.4	$422.2	$736.4	$ 0.0	$5.3
Net Income				104.7		
Common stock dividends ($2.20 per share)				(103.9)		
Common stock issued:						
LESOP	2,000	20.0	71.8		(91.7)	
Dividend Reinvestment Plan	64	0.6	2.4			
Long-Term Incentive Plan	165	1.7	5.3			
Public Offering	2,600	26.0	97.5			
Other				1.1	2.2	(0.2)
Balance at December 31, 1990	50,472	504.7	599.2	738.3	(89.5)	5.1
Net Income (loss)				(694.4)		
Common stock dividends ($1.16 per share) (Note 2)				(58.6)		
Common stock issued:						
Dividend Reinvestment Plan	75	0.8	2.4			
Long-Term Incentive Plan	12	0.1	0.4			
Other			(0.2)	1.2	2.5	(5.1)**
Balance at December 31, 1991	50,559	505.6	601.8	(13.5)	(87.0)	0.0
Net Income				51.2		
Sale of LESOP shares					17.0	
Balance at December 31, 1992	**50,559**	**$505.6**	**$601.8**	**$ 37.7**	**$(70.0)**	**$0.0**

*100 million shares authorized at December 31, 1992, 1991 and 1990—$10 par value.

**The Corporation's only foreign subsidiary, Columbia Gas Development of Canada Ltd., was sold during 1991.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

1. Summary of Significant Accounting Policies

A. Principles of Consolidation. The Consolidated Financial Statements include the accounts of the Corporation and all subsidiaries. All appropriate intercompany accounts and transactions have been eliminated, except for the Corporation's investment in Columbia LNG Corporation (see Note 12G).

On July 31, 1991, the Corporation and its wholly-owned subsidiary, Columbia Gas Transmission Corporation (Columbia Transmission), filed separate petitions seeking protection under Chapter 11 of the Federal Bankruptcy Code. The debtor companies are operating their businesses as debtors-in-possession (DIP) under the jurisdiction of the United States Bankruptcy Court for the District of Delaware (Bankruptcy Court). As such, the debtor companies cannot engage in transactions considered to be outside the ordinary course of business without obtaining Bankruptcy Court approval (see Note 2).

The accompanying financial statements reflect all adjustments necessary in the opinion of management to present fairly the results of operations in accordance with generally accepted accounting principles applicable to a going concern, which contemplates the realization of assets and payment of liabilities in the ordinary course of business. As a result of the reorganization proceedings under Chapter 11, the debtor companies may take, or be required to take, actions which may cause assets to be realized, or liabilities to be liquidated, for amounts other than those reflected in the financial statements. The appropriateness of continuing to present financial statements on a going concern basis is dependent upon, among other things, the terms of the ultimate plan of reorganization, future profitable operations, the ability to comply with DIP and other financing agreements and the ability to generate sufficient cash from operations and financing sources to meet obligations. The consolidated financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts, or the amounts and classification of liabilities that might be necessary as a result of the outcome of the uncertainties discussed herein.

Certain reclassifications have been made to the 1991 and 1990 financial statements to conform to the 1992 presentation.

B. Basis of Accounting for Rate-Regulated Subsidiaries. Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," provides that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it reasonable to assume that such rates can be charged and collected. In 1985, it was determined that the Corporation's interstate transmission companies no longer met these criteria, and consequently, these companies discontinued the application of the provisions of SFAS No. 71. In 1992, management concluded that it was no longer appropriate for Columbia LNG Corporation (Columbia LNG) to continue application of SFAS No. 71 (see Note 12G). The Corporation's gas distribution subsidiaries follow the accounting and reporting requirements of SFAS No. 71.

C. Gas Utility and Other Plant and Related Depreciation. Property, plant and equipment (principally utility plant) are stated at original cost. The cost of gas utility and other plant of the distribution companies includes an allowance for funds used during construction (AFUDC).

In addition, Columbia Gas of Ohio, Inc. is permitted to include in its plant investment post-in-service carrying charges on those eligible plant investments which are placed in service between December 31, 1990, and December 31, 1994. Subject to commission approval, the carrying charges are also authorized to be included in base rates in subsequent rate filings.

Property, plant and equipment of other subsidiaries includes interest during construction (IDC). The before-tax rates for AFUDC and IDC were as follows:

Year Ended December 31 (%)	**1992***	1991*	1990
AFUDC	**8.0**	8.0	9.4
IDC	**9.6**	9.6	9.5

*The portion of interest capitalized by subsidiaries during the period for which the Corporation is in bankruptcy is eliminated in the Consolidated Financial Statements. The 1992 and 1991 rates represent those in effect prior to the Chapter 11 filings.

Improvements and replacements of retirement units are capitalized at cost. When units of property are retired, the accumulated provision for depreciation is charged with the cost of the units and the cost of removal, net of salvage. Maintenance, repairs and minor replacements of property are charged to expense. The Corporation's subsidiaries provide for annual depreciation on a composite straight-line basis. The annual depreciation rates were as follows:

Year Ended December 31 (%)	**1992**	1991	1990
Transmission property	**2.6**	2.6	2.6
Distribution property	**3.3**	3.6	3.7

D. Oil and Gas Producing Properties. The Corporation's subsidiaries engaged in exploring for and developing oil and gas reserves follow the full-cost method of accounting. Under this method of accounting, all productive and nonproductive costs directly identified with acquisition, exploration and development activities are capitalized in countrywide cost centers. If costs exceed the sum of the estimated present value of the cost centers' net future oil and gas revenues and the lower of cost or estimated value of unproved properties, an amount equivalent to the excess is charged to current depletion expense. Gains or losses on the sale or other disposition of oil and gas properties are normally recorded as adjustments to capitalized costs.

Depletion for domestic subsidiaries is based upon the ratio of current-year revenues to expected total revenues, utilizing current prices, over the life of production. Depletion for the Canadian subsidiary, which was sold as of December 31, 1991, was based upon the ratio of volumes produced to total reserves.

E. Futures Contracts. Futures transactions are used from time to time to hedge prices of crude oil, natural gas production, propane inventories and natural gas purchase and sales commitments, in order to minimize the risk of market fluctuations. Under internal guidelines, hedging positions for oil and gas production can be taken for up to 80% of the expected uncommitted monthly production. Gains and losses on the futures transactions are recognized when the hedged transaction is complete.

F. Gas Inventory. Gas inventory is carried at cost on a last-in, first-out (LIFO) basis. The estimated replacement cost of gas inventory (including noncurrent) in excess of carrying amounts at December 31, 1992, was approximately $638 million for Columbia Transmission and $68 million for the distribution companies. Liquidation of LIFO layers related to gas delivered by the distribution companies does not affect income since the effect is passed through to customers as part of purchased gas adjustment tariffs. Columbia Transmission also reflects billing adjustments for LIFO liquidation, except for capitalized costs associated with certain producer payments not eligible for recovery in gas adjustment tariffs.

G. Income Taxes and Investment Tax Credits. The Corporation and its subsidiaries account for income taxes under the provisions of SFAS No. 109, "Accounting for Income Taxes" (see Note 4B).

The Corporation and its subsidiaries record income taxes to recognize full interperiod tax allocations. Under the liability method, deferred income taxes are recognized for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities.

Previously recorded investment tax credits of the gas distribution subsidiaries were deferred and are being amortized over the life of the related properties to conform with regulatory policy.

H. Estimated Rate Refunds. Certain rate-regulated subsidiaries collect revenues subject to refund pending final determination in rate proceedings. In connection with such revenues, estimated rate refund liabilities are recorded which reflect management's current judgment of the ultimate outcome of the proceedings. No provisions are made when, in the opinion of management, the facts and circumstances preclude a reasonable estimate of the outcome.

I. Deferred Gas Purchase Costs. The Corporation's gas distribution subsidiaries defer differences between gas purchase costs and the recovery of such costs in revenues, and adjust future billings for such deferrals on a basis consistent with applicable tariff provisions.

J. Revenue Recognition. The Corporation's rate-regulated subsidiaries bill customers on a monthly cycle billing basis. Revenues are recorded on the accrual basis including an estimate for gas delivered but unbilled at the end of each accounting period. Columbia Transmission also records revenues to reflect future billing adjustments to recover or refund the difference between current gas costs and amounts billed through its purchased gas adjustment tariff.

2. Reorganization Proceedings under Chapter 11 of the Bankruptcy Code

A. General. Under the Bankruptcy Code, actions by creditors to collect prepetition indebtedness are stayed and other contractual obligations may not be enforced against either the Corporation or Columbia Transmission. As debtors-in-possession, both the Corporation and Columbia Transmission have the right, subject to Bankruptcy Court approval and certain other limitations, to assume or reject executory contracts and unexpired leases. In this context, "rejection" means that the debtor companies are relieved from their obligations to perform further under the contract or lease but are subject to a claim for damages for the breach thereof. Any claims for damages resulting from rejection are treated as general unsecured claims in the reorganization. The parties affected by these rejections may file claims with the Bankruptcy Court in accordance with bankruptcy procedures. Prepetition claims which were contingent or unliquidated at the commencement of the Chapter 11 proceeding are generally allowable against the debtor-in-possession in amounts fixed by the Bankruptcy Court. Substantially all liabilities as of the petition date are subject to resolution under plans of reorganization to be approved by the Bankruptcy Court after submission to any required vote by affected parties. The Corporation's reorganization plan also requires approval by the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935.

B. Prepetition Obligations. Columbia Transmission's prepetition obligations include secured and unsecured debt payable to the Corporation, estimated supplier obligations, estimated rate refunds, accrued taxes and other trade payables and liabilities. Prepetition obligations of the Corporation primarily represent debentures, bank loans and commercial paper outstanding on the filing date together with accrued interest to that date. A substantial amount of Columbia Transmission's liabilities subject to Chapter 11 proceedings relate to amounts owed to the Corporation. Columbia Transmission's borrowings have been funded by the Corporation on a secured basis since June 1985. Under an Inventory Financing Agreement, the Corporation agreed to lend Columbia Transmission up to $410 million, which was the amount outstanding on the petition date. The loan is secured by Columbia Transmission's gas in underground storage. In addition, substantially all of Columbia Transmission's other assets have been pledged to the Corporation as security for First Mortgage Bonds issued by Columbia Transmission to the Corporation. On the petition date, the principal amount of the First Mortgage Bonds outstanding was $930.4 million. Prepetition and postpetition interest on secured debt owed by Columbia Transmission to the Corporation is approximately $207.1 million at December 31, 1992. In addition to these secured claims, the Corporation has an unsecured claim against Columbia Transmission of $351 million in installment notes issued prior to 1985 and accrued interest to the petition date.

The Official Committee of Unsecured Creditors of Columbia Transmission (Columbia Transmission Creditors' Committee) filed a complaint (Intercompany Complaint) against the Corporation and Columbia Natural Resources with the Bankruptcy Court alleging that the $1.7 billion of debt securities held by the Corporation should be recharacterized as capital contributions (rather than loans) and equitably subordinated to the claims of Columbia Transmission's other creditors. The Intercompany Complaint also challenges interest and dividend payments made by Columbia Transmission to the Corporation of approximately $500 million for the period from 1988 to the petition date. The Intercompany Complaint also challenges the 1990 property transfer from Columbia Transmission to Columbia Natural Resources as an alleged fraudulent transfer. The exploration and production properties of Columbia Natural Resources had a reserve value of $451 million (utilizing SEC standardized measurement procedures) as of December 31, 1992, a significant portion of which had been transferred from Columbia Transmission. In May 1992, the Columbia Transmission Creditors' Committee filed a motion to transfer this complaint from the Bankruptcy Court to the U.S. District Court. On June 11, 1992, the Corporation filed a motion with the Bankruptcy Court seeking dismissal of, or summary judgment on, principal portions of the Intercompany Complaint. The U.S. District Court denied the Columbia Transmission Creditors' Committee motion on February 9, 1993, which permits the Bankruptcy Court to decide the Corporation's pending motion for summary judgment. Management believes that the Intercompany Complaint is without merit; however, the ultimate outcome of these issues is uncertain at this stage of the proceedings.

The resolution of these issues could have a significant impact on the value of the estates of Columbia Transmission and the Corporation. Dependent upon the value of the Columbia Transmission estate, as well as the standing and value of the Corporation's debt investment, management will evaluate the feasibility of: (1) obtaining financing for reorganization, and/or (2) restructuring the Columbia Gas System.

The Internal Revenue Service (IRS) filed identical claims of $553.7 million against both debtor companies and the consolidated Columbia Gas System for the tax years 1985–1990. Through year-end, negotiations with IRS representatives have resulted in tentative agreement on a number of issues and substantial progress on two of the remaining three issues. The accompanying financial statements reflect the effect of the tentative agreements.

The Corporation and the IRS are in the early stages of discussion on the remaining and most significant issue, the payments to producers under Columbia Transmission's 1985 contract reformation effort. The IRS position on the producer payment issue, if sustained, could result in a deficiency of approximately $250 million. Management believes the deductions claimed in filed tax returns are appropriate and supportable and, accordingly, has not recorded any reserves for this issue.

Management recognizes the importance of resolving this issue due to the significant effect the issue has on creditors, stockholders, and its reorganization objectives. Although management prefers to settle this issue through negotiation rather than protracted litigation, it retains all rights to pursue this latter alternative to achieve a favorable resolution. The future earnings impact, if any, associated with the ultimate resolution of these remaining issues is not possible to predict with certainty because of the complexity of the matters, as well as the timing and method of resolution.

Columbia Transmission has recorded liabilities of approximately $1 billion to reflect the estimated effects of its high-cost producer contracts and estimated supplier obligations associated with pricing disputes and take-or-pay obligations for historical periods. Studies supporting these liabilities are based on projections of future spot-market prices and contract deliverability as well as contract pricing, discount rate and measurement date assumptions. These assumptions are not necessarily the same as those that would be applicable in the final measurement of contract rejection damages resulting from Columbia Transmission's rejection, with Bankruptcy Court approval, of more than 4,600 high-cost gas purchase contracts with producers. Claims associated with these contracts exceed $20 billion. The Bankruptcy Court has approved the appointment of a mediator to implement a claims estimation procedure related to the rejected high-cost producer contracts, which could ultimately result in liabilities materially different from recorded amounts.

Claims totalling nearly $350 million have also been filed against Columbia Transmission by its customers that generally seek to protect rights associated with any revenues collected subject to refund in general rate filings and purchased gas adjustment filings, including matters subject to court appeals. Appropriate reserves for rate refund liabilities have been recorded for these matters to reflect management's judgment of the ultimate outcome of the proceedings.

On July 6, 1992, the U.S. District Court for the District of Delaware overturned a Bankruptcy Court ruling which allowed Columbia Transmission to flow through to customers a portion of postpetition refunds received from upstream suppliers relating to prepetition periods and to pay prepetition Gas Research Institute (GRI) surcharges. The Bankruptcy Court had ruled the funds were held by Columbia Transmission in trust and were therefore payable because they were not part of Columbia Transmission's estate. Columbia Transmission, the Columbia Transmission Creditors' Committee, and customers, among others, have appealed the U.S. District Court decision to the United States Court of Appeals for the Third Circuit. On October 2, 1992, the Federal Energy Regulatory Commission (FERC) filed a brief in support of Columbia Transmission's appeal on the refund flowthrough and GRI issues. If the U.S. District Court decision is upheld, all such amounts will be unsecured claims subject to distribution under Columbia Transmission's reorganization plan.

On October 15, 1992, the FERC authorized Columbia Transmission to suspend all remaining flowthrough payments to upstream pipelines and all related billings and billing adjustments to its customers pending the outcome of the appeals of the U.S. District Court decision.

Pipeline suppliers have filed protective proofs of claims against Columbia Transmission for contingent liabilities of approximately $900 million in the event that Columbia Transmission decides to reject their contracts. Except for relatively minor commitments, management has no current intention to seek Bankruptcy Court approval for rejection of these contracts; therefore, no liability associated with this matter has been reflected in the accompanying financial statements. However, implementation of FERC Order No. 636 could significantly alter historical contractual relationships between Columbia Transmission and its upstream pipeline suppliers (see Note 3B for additional information).

On August 18, 1992, the Corporation filed objections to more than 7,100 proofs of claim filed against the Corporation. These objections largely sought to expunge claims made by bondholders, stockholders and commercial paper holders because stockholders are not creditors of the Corporation and because the debtholders' claims are duplicative of other claims made on the claimants' behalf by their representatives. The objections also sought to disallow, reduce or reclassify other claims. On January 12, 1993, the Bankruptcy Court issued an order granting the requested relief. As a result, only 400 of the approximately 7,500 claims filed against the Corporation remain to be resolved.

The Pension Benefit Guaranty Corporation (PBGC) filed claims of $150 million against both the Corporation and Columbia Transmission alleging that if the retirement plan had been terminated by March 31, 1992, it would have been underfunded. Management believes that the claims made by the PBGC are inappropriate and in error since the Bankruptcy Court has approved continued operation of the plan, required annual contributions are being made, there is no intention to terminate the plan and the plan is not underfunded. Management further believes that PBGC's claim can be resolved without any financial consequences to the Corporation or Columbia Transmission. On January 29, 1993, PBGC confirmed that while it remains confident that issues regarding its claims can be resolved by mutual agreement, PBGC has decided not to proceed further with settlement negotiations regarding withdrawal of its claims at the present time due to the uncertainties associated with the bankruptcy proceedings. At December 31, 1992, the date of the latest actuarial valuation, plan assets exceeded the accumulated benefit obligations by $144.5 million.

The accompanying Consolidated Balance Sheets include approximately $4 billion of liabilities subject to the Chapter 11 proceedings of the Corporation and Columbia Transmission as follows:

($ in millions)	1992	1991
Corporation		
Debentures:		
$6\frac{1}{4}$% Series due October 1991	12.0	12.0
$6\frac{5}{8}$% Series due October 1992	7.4	7.4
$7\frac{1}{4}$% Series due May 1993	15.0	15.0
9% Series due August 1993	150.0	150.0
7% Series due October 1993	12.0	12.0
9% Series due October 1994	20.2	20.2
$8\frac{3}{4}$% Series due April 1995	16.2	16.2
$9\frac{1}{8}$% Series due October 1995	22.0	22.0
$10\frac{1}{8}$% Series due November 1995	18.6	18.6
$8\frac{3}{8}$% Series due March 1996	32.9	32.9
$9\frac{1}{8}$% Series due May 1996	18.6	18.6
$8\frac{1}{4}$% Series due September 1996	26.4	26.4
$7\frac{1}{2}$% Series due March 1997	23.3	23.3
$7\frac{1}{2}$% Series due June 1997	26.3	26.3
$7\frac{1}{2}$% Series due October 1997	28.4	28.4
$7\frac{1}{2}$% Series due May 1998	23.7	23.7
$10\frac{1}{4}$% Series due May 1999	25.0	25.0
$9\frac{7}{8}$% Series due June 1999	21.8	21.8
$10\frac{1}{4}$% Series due August 2011	100.0	100.0
$10\frac{1}{2}$% Series due June 2012	200.0	200.0
$10\frac{3}{20}$% Series due November 2013	100.0	100.0
$9\frac{1}{5}$% to $9\frac{1}{2}$% Series A Medium-Term Notes due 1998 through 2019	200.0	200.0
$8\frac{19}{20}$% to $9\frac{49}{50}$% Series B Medium-Term Notes due 1998 through 2020	200.0	200.0
$9\frac{11}{20}$% to $9\frac{37}{50}$% Series C Medium-Term Notes due 2000 through 2020	50.0	50.0
	1,349.8	1,349.8
Unamortized debt discount, less premium	(7.2)	(7.2)
	1,342.6	1,342.6
Subordinated Guarantee of Leveraged Employee Stock Ownership Plan debt	87.0	87.0
Short-term debt:		
Commercial Paper	266.5	266.5
Bank Loans	621.0	621.0
Prepetition debt obligations	2,317.1	2,317.1
Other	65.1	73.2
Total	2,382.2	2,390.3
Less amounts payable to affiliates	4.9	4.9
Total Corporation	2,377.3	2,385.4

($ in millions)	1992	1991
Columbia Transmission		
Debt obligations and other payables to the Corporation	1,890.8	1,773.1
Payables to other affiliates	67.1	64.1
Estimated supplier obligations	1,253.9	1,217.0
Estimated rate refunds	217.5	187.8
Taxes	44.5	66.2
Other	74.0	47.1
Total	3,547.8	3,355.3
Less amounts payable to affiliates	1,957.9	1,837.2
Total Columbia Transmission	1,589.9	1,518.1
Total	3,967.2	3,903.5

C. Payment of Dividends and Debt Service. The Corporation's Board of Directors suspended the payment of dividends on the Corporation's common stock on June 19, 1991. The Corporation also discontinued most payments related to debt service. Columbia Transmission has suspended dividend, interest and debt payments to the Corporation. The Corporation and Columbia Transmission have also suspended the payment of most other prepetition obligations. Management cannot predict at this time when or whether any financial restructuring plans will be approved or what provisions, if any, such plans would contain as related to the resumption of dividends, debt service and other payments.

D. Bar Date. The Bankruptcy Court established March 18, 1992, as the deadline (the Bar Date) for most creditors to file claims against the debtor companies. Federal and state environmental agencies were specifically exempted from the effect of the Bar Date. Affected creditors who failed to file proofs of claims by the Bar Date are now forever barred from voting on, or receiving distributions, under any plan of reorganization. Approximately 14,000 total claims were filed by creditors against both debtor companies.

E. Plan of Reorganization. Although progress on developing plans of reorganization continues, provisions of the plan of reorganization for Columbia Transmission cannot yet be determined. Since the ultimate plan of reorganization of the Corporation depends in part on the value ascribed to Columbia Transmission, the ultimate value of the securities of Columbia Transmission owned by the Corporation and the outcome of the Intercompany Complaint, provisions of the Corporation's plan also cannot yet be determined. Provisions of such plans, or inability by the Corporation and/or Columbia Transmission to obtain approval of a plan, could have a material adverse effect on the Corporation and its subsidiaries and on the rights of shareholders and holders of debt and other obligations. Until March 25, 1993, both the Corporation and Columbia Transmission have exclusive rights to file their individual plans of reorganization. It is anticipated that a request to extend this period of exclusivity will be submitted to the Bankruptcy Court.

F. Reorganization Items. During 1992 and 1991, the Corporation and Columbia Transmission have incurred the following expenses, associated with professional fees and related expenses partially offset by interest income earned on cash accumulated from the suspension of payments related to prepetition liabilities:

($ in millions)	1992	1991
Professional fees and related expenses	**30.7**	18.8
Interest income on accumulated cash	**(26.9)**	(4.5)
Other reorganization items	**4.5**	0.1
Net Reorganization Items	**8.3**	14.4

G. Financial Information for the Debtor Companies. Condensed financial information for the Corporation and Columbia Transmission as of, and for, periods ended December 31, is as follows:

	Corporation		Columbia Transmission	
($ in millions)	1992	1991	1992	1991
Current assets				
Cash and temporary cash investments	**8.0**	9.8	**804.6**	386.5
Other	**429.1**	331.5	**637.9**	802.3
Total current assets	**437.1**	341.3	**1,442.5**	1,188.8
Current liabilities	**(16.8)**	(174.6)	**(449.6)**	(286.7)
Working capital	**420.3**	166.7	**992.9**	902.1
Noncurrent assets	**3,119.7**	3,233.9	**2,225.1**	2,085.2
Estimated liabilities subject to Chapter 11 proceedings	**(2,382.2)**	(2,390.3)	**(3,547.8)**	(3,355.3)
Noncurrent liabilities	**(82.7)**	(3.4)	**(169.2)**	(113.4)
Net Equity	**1,075.1**	1,006.9	**(499.0)**	(481.4)
Operating revenues	**–**	–	**1,363.8**	1,003.5
Operating expenses	**10.3**	9.5	**(1,256.9)**	2,213.0
Operating income (loss)	**(10.3)**	(9.5)	**106.9**	(1,209.5)
Other income (deductions)	**154.7**	(644.6)	**(118.0)**	(133.8)
Income taxes	**53.5**	36.4	**6.5**	(463.3)
Extraordinary item	**(39.7)**	–	**–**	–
Cumulative effect of accounting changes	**–**	(3.9)	**–**	50.5
Net Income (Loss)	**51.2**	(694.4)	**(17.6)**	(829.5)
Net Cash from Operations	**59.4**	29.9	**510.3**	240.5

3. Regulatory Matters

A. Columbia Transmission has collected and continues to collect revenues from its customers associated with the passthrough of upstream pipeline supplier take-or-pay and contract reformation costs under FERC Order Nos. 500 and 528. Certain customers have challenged recovery of such costs, which total $122 million, on the basis that a 1985 rate settlement precludes collection. The FERC has consistently denied the customers' assertions and appeals have been filed with the U.S. Court of Appeals, D.C. Circuit. Management continues to believe these challenges are without merit and the FERC orders, which support collection of these costs, will ultimately be upheld.

B. In April 1992, the FERC issued Order No. 636 (Order 636), its final rule on Pipeline Service Obligations and Equality of Transportation Services by Pipelines. The FERC states that this order is the final stage in its effort to fundamentally change the role of pipelines from providing a merchant function to one in which they perform principally as transporters of gas that distribution companies and end users purchase directly from producers and other suppliers. (Reference is made to the Management's Discussion and Analysis in the Transmission and Distribution sections for additional information.)

Order 636 requires pipelines to "unbundle" their sales, transportation and storage services and to provide and price these services separately. In addition, the FERC requires changes to pipeline rate design which it believes will improve competitiveness of pipeline rates and provide more accurate market signals. The FERC has ordered all pipelines to fully implement Order 636 before the 1993-94 winter, and has established restructuring proceedings for each pipeline. In December 1992, Columbia Transmission and Columbia Gulf Transmission (Columbia Gulf) made filings with the FERC setting forth each company's proposal for compliance with Order 636.

In Order 636, the FERC provided that pipelines may recover all prudently incurred costs resulting from the transition to Order 636 and set general guidelines for their recovery. However, the FERC stated that filings to recover such costs should not be made until a pipeline's service restructuring proposal, that identifies various transition costs, has been approved. With respect to gas supply realignment costs, costs associated with reforming or terminating above-market price supply contracts, Columbia Transmission noted in its filing that the majority of such costs on its system will be determined in the context of the bankruptcy proceedings regarding the treatment of producer contract rejection costs. The company stated that the ultimate level of such costs is uncertain and that recovery would be pursued in future filings with the FERC. In February 1993, responses to the transmission companies' compliance filings were filed with the FERC by interested parties which seek to exclude from transition costs certain producer contract rejection costs. Columbia Transmission's efforts to recover gas supply realignment costs are expected to be strongly opposed. Filings to recover such costs will be made at a later date.

The compliance filings of the transmission subsidiaries contemplate collection of estimated transition costs in several areas. Purchased gas costs associated with Columbia Transmission's merchant function not collected from customers are estimated to be in the range of $150 million to $175 million at November 1, 1993. The accompanying balance sheet reflects receivables for such gas costs of $203.5 million at December 31, 1992. Further, the compliance filing details procedures to offer Columbia Transmission's customers its existing firm capacity on upstream pipelines, with demand charge commitments of approximately $108 million annually. Management expects a significant portion of this capacity to be acquired by existing customers and therefore any remaining Columbia Transmission commitment should be significantly below current levels. The filing also addresses the potential for some portion of Columbia Transmission's net investment in gathering facilities ($68 million at December 31, 1992) to be considered a stranded investment for which recovery in rates would be requested. The amount of any such stranded gathering facilities depends upon the rate design in effect, the results of efforts undertaken to sell or otherwise dispose of such properties, and other factors. As noted above, filings to recover any such costs will not occur until after approval of the service aspects of the implementation is complete; therefore, the ultimate outcome cannot be predicted with certainty. Based upon the provisions of Order 636, management believes that all of these costs will be recovered.

With the pending implementation of Order 636, Columbia Transmission's management has evaluated its long-term commitment to the merchant function. As a result of this review and negotiations with customers, management now expects that Columbia Transmission will no longer provide a significant merchant function after November 1, 1993. Consequently, a writedown of $38.6 million (pre-tax) was recorded in 1992 to reflect the loss of value of certain capitalized gas costs that are in excess of amounts to be amortized in 1993.

C. In 1989, the FERC authorized Kentucky West Virginia Gas Company (Kentucky West Virginia) to retroactively collect higher prices from Columbia Transmission for certain gas it produced and sold between 1979 and 1983. The order permits Kentucky West Virginia to directly bill its customers, including Columbia Transmission, for the price increase based on their levels of purchases during this period. Kentucky West Virginia filed to recover approximately $27 million, including interest, from Columbia Transmission effective March 15, 1989, but reserved the right to seek recovery of additional amounts once certain conditions were met.

In 1991, the FERC rejected a settlement Columbia Transmission had previously reached with Kentucky West Virginia. In August 1992, Kentucky West Virginia and Columbia Transmission filed a revised settlement with the FERC that includes a bankruptcy claim of $19 million relating to higher prices for Kentucky West Virginia's gas production for prior years and a $7 million bankruptcy claim pertaining to Columbia Transmission's rejection of its gas purchase contract with Kentucky West Virginia. On November 6, 1992, the Bankruptcy Court approved Columbia Transmission's rejection of the Kentucky West Virginia contract. Through 1992, Columbia Transmission has recorded liabilities totalling $26 million to reflect the proposed settlement. The settlement was approved by the FERC in February 1993, and is now subject to Bankruptcy Court approval. If the modifications are acceptable to Columbia Transmission and Kentucky West Virginia, it will be submitted for Bankruptcy Court approval.

4. Accounting Changes

A. In the fourth quarter of 1991, the Corporation adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," (OPEB) retroactive to January 1, 1991. This method of accounting for postretirement benefits accrues the actuarially determined costs for life insurance and medical benefits ratably from the date an employee becomes eligible for such benefits. The Corporation's subsidiaries previously expensed these costs as cash payments were made. As permitted under SFAS No. 106, the subsidiaries elected to record the full amount of their estimated accumulated postretirement benefits obligation other than pensions of $223.8 million. These obligations represent the actuarial present value, discounted at 8%, of the postretirement benefits to be paid to current employees and retirees based on services rendered.

The present value of the postretirement benefit obligation to be paid to current and retired employees for all the distribution subsidiaries amounts to approximately $131.4 million as of December 31, 1992. Of this amount, $127.2 million has been deferred as a regulatory asset pending anticipated recovery through rates in various jurisdictions. The Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board has recently issued guidelines establishing criteria for recording such a regulatory asset, including a requirement for collection of accrual basis expense in rates and recovery of the transition obligation within 20 years. These criteria will not necessarily be adopted by the public utility commissions regulating the distribution subsidiaries. Differences in requirements between the accounting rules and the ratemaking decision ultimately adopted could result in a writedown of some or all of this regulatory asset. The distribution subsidiaries, as well as the Corporation's other operating companies, have implemented cost-containment measures designed to reduce their OPEB obligations. In addition to other measures, employees will be required to share a portion of their postretirement health benefit costs and guidelines have been established redefining years of service requirements before an employee is eligible for retiree health benefits. Other cost-saving plans are being reviewed for consideration in an ongoing effort to effectively manage OPEB costs.

In Ohio, the staff of the Public Utilities Commission has taken a position that would allow recovery of OPEB costs on an accrual basis. However, the method of recognizing the unfunded transition obligation at the time of adoption of SFAS No. 106 and the amortization period for the obligation is likely to be determined on a case-by-case basis. A final order from the commission regarding the outcome of this investigation is expected in the near future. The amount of the Columbia Gas of Ohio regulatory asset in the accompanying balance sheet was $77.4 million as of December 31, 1992.

In November 1992, the Pennsylvania Public Utility Commission (PPUC) issued an order in response to a coalition of several utilities filing a joint petition requesting the deferral of OPEB costs. Basically, the PPUC indicated that the appropriate ratemaking treatment for OPEB costs is pay-as-you-go, which may, on a case-by-case basis, be modified to include rate recovery of funded amounts. The PPUC further stated that the appropriate level of transition costs to be allowed will also be decided on a case-by-case basis. At December 31, 1992, the carrying value of Columbia Gas of Pennsylvania's (CPA) regulatory asset was approximately $31.6 million. A recent order filed by the PPUC for another utility's pending rate case allowed only pay-as-you-go treatment of OPEB costs until the PPUC could be shown that a viable cost-containment program has been effectuated. The PPUC also based its order on its determination that the utility did not adequately demonstrate how it plans to fund OPEB costs. The PPUC directed that company to record the difference between the level of OPEB expense and the pay-as-you-go method as a regulatory asset and agreed to address, in a separate rate proceeding, the recovery of OPEB accruals that are deemed prudently incurred. CPA has taken certain steps which it believes differentiates its facts and circumstances from this decision and will help ensure a favorable ruling from the PPUC on the recovery of these costs. CPA is committed to advance funding of the costs for retirees benefits in an irrevocable trust fund to the extent these costs are allowed in rates.

In January 1993, the Maryland Public Service Commission decided to defer its decision on Columbia Gas of Maryland's application to recover OPEB costs until a generic decision is made at a later date. In early 1993, an order was issued by the Virginia State Corporation Commission that provides for the full recovery of OPEB cost accruals to the extent that they are funded, and the recovery of transition costs over a period of 40 years. Any timing difference between OPEB expense and amounts recovered may be deferred as a regulatory asset. However, as a result of the EITF guidelines, the Virginia distribution subsidiary expensed $4.2 million in 1992. The Kentucky commission has indicated that it will address the recovery of OPEB costs on a case-by-case basis through rate filings.

Although proceedings in the applicable state jurisdictions are not final, based on currently available information, management believes rate recovery mechanisms will be adopted that permit continued regulatory asset treatment in accordance with recent EITF guidelines.

B. In February 1992, the Financial Accounting Standards Board issued SFAS No. 109, "Accounting for Income Taxes." The Corporation adopted SFAS No. 109 in the fourth quarter, retroactive to January 1, 1992. This Statement supersedes SFAS No. 96, "Accounting for Income Taxes," which was adopted by the Corporation in 1991 and improved earnings by $170 million. SFAS No. 109 changes the criteria for recognition and measurement of deferred tax assets and reduces complexity. The adoption of SFAS No. 109 had no impact on the Corporation's financial statements.

C. In November 1992, the Financial Accounting Standards Board issued SFAS No. 112, "Employers' Accounting for Postemployment Benefits." This Statement requires employers to recognize any obligation which exists to provide benefits to former or inactive employees after employment, but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits such as healthcare and life insurance coverage. This Statement will be effective for fiscal years beginning after December 15, 1993, and the Corporation plans to adopt the Statement on January 1, 1994. Based on the facts and circumstances known today, the pre-tax impact to the Corporation and its subsidiaries would be approximately $9 million. Depending on the recoverability of this expense in the distribution subsidiaries' rates, the net charge to earnings upon adoption would be in the $3 million to $6 million range.

5. Income Taxes

The components of income taxes are as follows:

Year Ended December 31 ($ in millions)	**1992**	1991	1990
Income Taxes			
Currently payable			
Federal	**90.0**	106.7	68.1
State	**10.8**	8.0	4.4
Total Currently Payable	**100.8**	114.7	72.5
Deferred			
Federal	**(32.2)**	(510.2)	(15.5)
State	**3.3**	(13.7)	3.6
Total Deferred	**(28.9)**	(523.9)	(11.9)
Deferred Investment Credits	**(1.4)**	(1.8)	(2.7)
Income taxes included in income before extraordinary item and cumulative effect of accounting changes	**70.5**	(411.0)	57.9
Deferred tax related to extraordinary item and cumulative effect of accounting changes	**(20.4)**	(236.6)	–
Total Income Taxes	**50.1**	(647.6)	57.9

Total income taxes are different than the amount which would be computed by applying the statutory Federal income tax rate to book income before income tax. The major reasons for this difference are as follows:

Year Ended December 31 ($ in millions)	1992		1991		1990	
Book income (loss) before incomes taxes, extraordinary item and cumulative effect of accounting changes*	**161.4**		(1,205.8)		162.6	
Tax expense (benefit) at statutory Federal income tax rate	**54.9**	**34.0%**	(410.0)	(34.0)%	55.3	34.0%
Increases (reductions) in taxes resulting from:						
State income taxes, net of Federal income tax benefit	**9.8**	**6.1**	(4.7)	(0.4)	5.2	3.3
Estimated nondeductible expenses	**6.4**	**4.0**	3.3	0.3	–	–
Investment credits not deferred and amortization of credits deferred in prior years	**(1.4)**	**(0.9)**	(1.8)	(0.1)	(2.7)	(1.7)
Depreciation expense for accounting purposes over amounts claimed for income tax purposes	**–**	**–**	–	–	4.1	2.5
Effect of change in tax rates on certain deferred taxes previously provided	**–**	**–**	–	–	(5.6)	(3.4)
Other	**0.8**	**0.5**	2.2	0.1	1.6	0.9
Income Taxes Before Extraordinary Item and Cumulative Effect of Accounting Changes	**70.5**	**43.7%**	(411.0)	(34.1)%	57.9	35.6%

*Includes losses from foreign operations of $41.5 million and $21.8 million for 1991 and 1990, respectively.

At December 31 ($ in millions)	1992	1991
Net current liabilities (assets)		
Federal	**20.5**	22.7
State	**(0.8)**	(1.2)
Total	**19.7**	21.5
Net noncurrent liabilities		
Federal	**128.7**	158.8
State	**61.6**	58.6
Total	**190.3**	217.4
Total Deferred Income Taxes	**210.0**	238.9

Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The source of these differences and tax effect of each is as follows:

At December 31 ($ in millions)	1992	1991
Property basis differences	**606.6**	629.8
Accrued interest	**85.3**	28.5
Gas purchase costs	**51.5**	29.5
Partnership deferrals	**26.7**	29.2
Deferred revenue	**23.0**	18.1
Estimated supplier obligations	**(338.9)**	(336.3)
Estimated rate refunds	**(100.4)**	(36.1)
Postretirement benefits	**(44.7)**	(44.0)
Environmental liabilities	**(38.4)**	(18.5)
Capitalized inventory overheads	**(26.7)**	(24.4)
Unbilled utility revenue	**(15.1)**	(12.6)
Alternative minimum tax	**–**	(12.2)
Other	**(18.9)**	(12.1)
Total Deferred Income Taxes	**210.0**	238.9

6. Sale of Subsidiaries

A. The sale of Columbia Gas of New York, Inc. to New York State Electric & Gas Corporation was completed on April 5, 1991, and provided an increase to net income of $9.2 million. The total price was $57.5 million including $39.2 million for the 328,000 outstanding shares of common stock and $18.3 million for the outstanding debt.

B. The sale of Columbia Gas Development of Canada Ltd. (Columbia Canada), a wholly-owned Canadian oil and gas exploration and production subsidiary, to Anderson Exploration, Ltd. was effective as of December 31, 1991.

The sales price for Columbia Canada was $94.8 million. Of this amount, $27.7 million was placed in escrow as security for certain post-closing obligations of the Corporation including indemnification for potential losses arising from litigation involving Columbia Canada. The Corporation expects to receive all or substantially all of the escrow account when the litigation is concluded. Upon emergence from bankruptcy, the Corporation is obligated to deposit into the escrow account an additional $25 million (Canadian). As of December 31, 1992, $25.1 million, including accrued interest, remains in escrow for potential losses arising from litigation.

7. Pension and Other Postretirement Benefits

The Corporation has a trusteed, noncontributory pension plan which covers all regular employees, 21 years of age and older. The plan provides defined benefits based on the highest three-year average annual compensation in the final five years of service and years of credited service. It is the Corporation's funding policy to contribute to the plan based on a percentage of payroll, subject to the statutory minimum and maximum limits.

The following table provides 1992–1990 pension cost components for the plan, along with additional relevant data:

Pension Costs ($ in millions)	1992	1991	1990
Service cost	**30.5**	21.7	20.3
Interest cost	**66.1**	63.2	59.2
Actual return on assets	**(55.8)**	(171.7)	10.6
Net amortization (deferral)	**(13.2)**	115.0	(74.6)
Net pension expense	**27.6**	28.2	15.5
Annual contribution	**23.5**	24.0	17.3
Assumed asset earnings rate	**9.0%**	9.0%	9.0%

Pension plan assets consist principally of common stock equities and fixed income securities. The following table reconciles plan assets and liabilities to the funded status of the plan:

Plan Assets and Obligations at December 31 ($ in millions)	1992	1991
Plan assets at fair value	**860.2**	845.6
Actuarial present value of benefit obligations:		
Vested benefits	**668.2**	649.5
Nonvested benefits	**47.5**	45.0
Accumulated benefit obligation	**715.7**	694.5
Effect of projected future salary increases	**199.9**	186.1
Total projected benefit obligation	**915.6**	880.6
Plan assets less than projected benefit obligation	**(55.4)**	(35.0)
Unrecognized net gain	**(18.1)**	(40.6)
Unrecognized prior service cost	**69.7**	74.4
Unrecognized transition obligation	**11.6**	12.8
Prepaid pension cost	**7.8**	11.6
Discount rate assumption	**7.5%**	7.5%
Average compensation growth rate	**6.0%**	6.0%

In addition to providing pension benefits, the Corporation's subsidiaries provide other postretirement benefits, including medical care and life insurance, which cover substantially all active employees upon their retirement. The following table provides the total postretirement benefit cost components recognized during 1992 and 1991 along with additional relevant data:

Other Postretirement Costs ($ in millions)	1992	1991
Service cost (benefits earned during period)	**13.3**	12.2
Interest cost on projected benefit obligation	**22.5**	21.4
Actual return on assets	**(2.9)**	(2.5)
Other net	**(0.4)**	(0.7)
Other postretirement costs	**32.5**	30.4
Transition obligation	**–**	223.8
Assumed asset earnings rate	**9.0%**	9.0%

Plan Assets and Obligations at December 31 ($ in millions)*		
Accumulated benefit obligation:		
Retirees	**179.7**	164.5
Fully eligible active plan participants	**68.2**	66.9
Other participants	**86.7**	65.0
Total	**334.6**	296.4
Plan assets at fair value	**(54.0)**	(37.6)
Unrecognized actuarial loss	**(30.8)**	(15.3)
Accrued postretirement benefit cost	**249.8**	243.5
Discount rate assumption	**7.5%**	7.5%
Average compensation growth rate	**6.0%**	6.0%

*Includes $127.2 million and $112.7 million for distribution subsidiaries capitalized as a regulatory asset in 1992 and 1991, respectively.

The healthcare cost trend rate assumption significantly affects the amounts reported. For example, a 1% increase in this rate would increase the accumulated postretirement benefit obligation by $18.3 million at December 31, 1992, and increase the net periodic cost by $2.8 million for the year. The postretirement benefit cost components for 1992 and 1991 were calculated assuming healthcare cost trend rates starting at 17% and decreasing to 6.5% after approximately 25 years.

The medical plans of the Corporation's subsidiaries are currently funded on a pay-as-you-go basis with the exception of Columbia Transmission and Columbia Gulf which began advance funding of their retiree medical liability in 1992. A FERC order allows collection of these costs in rates if the appropriate funds are placed in irrevocable trusts. The required trusts were established in December 1992. The funding of the postretirement obligation via trust funds for the Corporation's other subsidiaries is under continuing review.

All of the Corporation's subsidiaries participate in funding for postretirement life insurance benefits utilizing a voluntary employee beneficiary association trust. The Corporation's funding policy is to make annual contributions to this trust, subject to the statutory maximum tax-deductible limit. Employee contributions are not required.

8. Long-Term Incentive Plan

The Corporation has a Long-Term Incentive Plan (Plan) which provides for the granting of nonqualified stock options, stock appreciation rights and contingent stock awards as determined by the Compensation Committee of the Board of Directors. That committee also has the right to modify any outstanding award. A total of 1,500,000 shares of the Corporation's authorized common stock was initially reserved for issuance under the Plan's provisions. There were 332,185 shares remaining available for awards at December 31, 1992.

Stock appreciation rights, which are granted in connection with certain nonqualified stock options, entitle the holders to receive stock, cash or a combination thereof equal to the excess market value over the grant price. Transactions for the three years ended December 31, 1992, are as follows:

	Options		
	Without Stock Appreciation Rights	With Stock Appreciation Rights	Option Price Range
Outstanding 12/31/89	621,025	98,850	$34.30–$49.74
1990			
Granted	167,500	52,500	$46.68
Exercised	(149,595)	(5,840)	$34.30–$42.99
Cancelled	(22,195)	–	$34.30–$49.74
Converted	(19,580)	19,580	$34.30–$44.49
Outstanding 12/31/90	597,155	165,090	$34.30–$46.68
1991			
Granted	–	–	–
Exercised	(12,065)	(1,440)	$34.30–$42.99
Cancelled	(21,330)	–	$34.30–$46.68
Converted	–	–	–
Outstanding 12/31/91	563,760	163,650	$34.30–$46.68
1992			
Granted	**–**	**–**	**–**
Exercised	**–**	**–**	**–**
Cancelled	**(34,410)**	**–**	**$34.30–$46.68**
Converted	**–**	**–**	**–**
Outstanding 12/31/92	**529,350**	**163,650**	**$34.30–$46.68**
Exercisable 12/31/92	**281,230**	**89,900**	**$34.30–$44.49**

In addition to the options, a contingent stock award of 4,110 shares was granted to a key executive in 1991. Shares of common stock that have been issued for vested awards are as follows: 1992–none; 1991–none; and 1990–14,400 shares. At December 31, 1992, there were 4,110 awards outstanding.

9. Defined Contribution (Thrift) Plan

Eligible employees may participate in the Thrift Plan by contributing up to 16 percent of their monthly basic earnings to any one or more of several funds. The Corporation's participating subsidiaries make matching contributions of 50% to 100% of deposits made by each of its participating employees up to 6% of basic earnings based upon the months of participation in the plan by each employee. All employer matching contributions for participants under age 55 are invested by the Trustee in the fund holding common stock of the Corporation. Participants age 55 and older may invest their employer contributions in any one or more of the several funds. Employees are eligible for participation in the Thrift Plan after completing one year of service.

In 1990, the Corporation established a Leveraged Employee Stock Ownership Plan (LESOP). The LESOP was designed to pre-fund a portion of the matching obligation under the terms of the Thrift Plan and to utilize tax advantages afforded by the Internal Revenue Code.

In October 1991, the Board of Directors of the Corporation authorized the termination of the LESOP subject to the approval of the Bankruptcy Court. It is anticipated that the termination will be part of the Corporation's plan of reorganization. Upon termination, any shares of common stock of the Corporation remaining in the LESOP Trust account would be sold and the proceeds paid to the holders of debentures issued under the LESOP. Termination of the plan could result in pre-tax charges of approximately $58.7 million based on current stock prices. Any unpaid balance due would become subject to the subordinate guarantee of the Corporation and become a claim to be resolved as part of the reorganization plan. As of December 31, 1992, the LESOP suspense account held 1,416,155 shares.

The participating subsidiaries ceased making contributions to the LESOP for debt service payments but continue to contribute to the Thrift Plan those amounts necessary to fulfill the matching obligations to participants. Matching contributions to the Thrift Plan were $13.2 million, $8.6 million and $10.0 million in 1992, 1991 and 1990, respectively. Thrift Plan expenses were $13.2 million, $17.9 million, and $13.1 million for 1992, 1991 and 1990, respectively. The difference between matching contributions and expense for 1991 and 1990 was attributable to the additional expenses required under the now suspended LESOP.

10. Debt Obligations

The Corporation's filing for protection under the Bankruptcy Code constituted an event of default under substantially all of its debt agreements. Because payment of debt which existed at the filing date is suspended by the Bankruptcy Code, substantially all of the Corporation's debt, including short-term debt, has been classified as Liabilities Subject to Chapter 11 Proceedings. In addition, payment of interest on prepetition debt is suspended, and no interest expense on such debt will be recorded during the course of the bankruptcy proceedings.

Following the Chapter 11 filing, the Corporation received approval from the Bankruptcy Court and the SEC, under the Public Utility Holding Company Act of 1935, for debtor-in-possession financing (the DIP Facility). The DIP Facility is for up to $200 million and includes the availability of letters of credit of up to $50 million. The DIP Facility was reduced by the Corporation from $275 million to the current level on July 10, 1992. The Corporation will likely request an extension of the DIP Facility past the current September 1993 expiration date.

Columbia Transmission also maintains a DIP facility solely for the issuance of letters of credit for up to $25 million. Columbia Transmission has extended its DIP facility to December 31, 1994, to allow for letters of credit with terms for the full calendar year of 1994.

11. Disclosures about Fair Value of Financial Instruments

The Corporation, effective December 31, 1992, adopted SFAS No. 107, "Disclosures about Fair Value of Financial Instruments." The Statement extends existing fair value disclosure practices by requiring all entities to disclose the fair value of financial instruments, both assets and liabilities, recognized and not recognized in the Consolidated Balance Sheets, for which it is practicable to estimate fair value. For purposes of this disclosure, the fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced or liquidation sale. Fair value may be based on quoted market prices for the same or similar financial instruments, or on valuation techniques such as the present value of estimated future cash flows using a discount rate commensurate with the risks involved.

The uncertainties related to the outcome of the Corporation's Chapter 11 proceedings and the resulting effect upon the ultimate value of the Corporation's financial assets and liabilities add significantly to the uncertain nature of any estimate of fair value. The estimates of fair value required under SFAS No. 107 require the application of broad assumptions and estimates. Accordingly, any actual exchange of such financial instruments could occur at values significantly different from the amounts disclosed.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

As cash and temporary cash investments, current receivables, current payables, and certain other short-term financial instruments are all short-term in nature, their carrying amount approximates fair value. The estimated fair values of the Corporation's other financial instruments are reflected in the table below.

Long-term investments

Long-term investments include escrowed proceeds from the sale of the Canadian subsidiary (see Note 6B), which consist of hedged Canadian Treasury bills ($25.1 million). The Canadian Treasury bills are hedged with foreign currency contracts, so that the combined carrying amount of the asset and related hedging instrument approximates fair value. Also included are loans receivable ($15.6 million) whose estimated fair values are based on the present value of estimated future cash flows using an estimated rate for similar loans extended currently. It is not practicable to estimate the fair value of long-term receivables ($154.2 million) for the expected recovery by Columbia Transmission of certain gas purchase liabilities for which the timing and amount of payments to be received will be dependent on the outcome of the Chapter 11 proceedings. As discussed in Note 2, the uncertainties related to these proceedings could significantly influence the fair value of this financial instrument. The financial instruments included in long-term investments are primarily reflected in Investments and Other Assets in the Consolidated Balance Sheets.

Liabilities subject to Chapter 11 proceedings

The estimated fair value of the Corporation's debentures and medium-term notes is based on quoted market prices for those issues that are traded on an exchange, and estimates provided by brokers for other issues. However, quoted market prices and broker estimates inherently include judgments concerning the outcome of the Corporation's and Columbia Transmission's Chapter 11 proceedings. Note 2 discusses the uncertainties related to these proceedings which could significantly influence the fair value of these financial instruments. It was not practicable to estimate the fair value of the remaining long-term debt, which includes the Subordinated Guarantee of Leveraged Employee Stock Ownership Plan debt ($87.0 million) and miscellaneous debt of Columbia Transmission ($1.4 million), because no reliable measurement methodology exists. Prior to filing its petition for protection under Chapter 11 of the Bankruptcy Code, the Corporation regularly issued commercial paper, bank notes and other short-term debt instruments. The carrying amount of such securities ($892.6 million) is included in Liabilities Subject to Chapter 11 Proceedings. Payment of these obligations and any related interest is subject to approval by the Bankruptcy Court. Although investors from time to time may buy and sell these debt obligations, the terms of any such transactions are private and not disclosed to the Corporation. Because there can be no assurance as to the ultimate timing and amount of principal and interest repayments of these obligations, it is not practicable to determine their fair values.

The carrying amount of other Liabilities Subject to Chapter 11 Proceedings ($1,595.4 million) primarily represents accounts payable, accrued liabilities and other liabilities. As discussed in Note 2, these liabilities are subject to adjustment at the direction of the Bankruptcy Court. In addition, the timing of the ultimate payment of these liabilities, as well as interest (if any), is also subject to determination by the Bankruptcy Court. Accordingly, it is not practicable to determine the fair value of these liabilities.

At December 31, 1992 ($ in millions)	Carrying Amount	Fair Value
Long-term investments for which it is:		
Practicable to estimate fair value	40.8	41.0
Not practicable to estimate fair value	154.2	–
Liabilities subject to Chapter 11 proceedings for which it is:		
Practicable to estimate fair value		
Long-term debt	1,390.8	1,373.6
Not practicable to estimate fair value		
Long-term debt	88.4	–
Bank loans and commercial paper	892.6	–
Other	1,595.4	–

12. Other Commitments and Contingencies

A. Capital Expenditures. Capital expenditures for 1993 are estimated at $391 million. Of this amount, $69 million is for oil and gas operations, $173 million for transmission operations, $125 million for distribution operations and $24 million for other energy operations.

B. Producer Contract Matters. Columbia Transmission has rejected 4,673 natural gas purchase contracts which collectively made the company's gas sales rate noncompetitive. Customer requirements will be met with gas purchased under remaining contracts, from additional winter-only contracts, from underground storage facilities, and by gas purchased on the spot market. Rejection of additional contracts could result in liabilities that could require future charges against earnings.

C. Partnership Projects. Columbia Gulf is a general partner in the Trailblazer, Overthrust and Ozark partnerships, all of which are nonrecourse, project-financed pipelines. Columbia Transmission is a shipper whose service contracts with the pipelines were assigned to the banks (or in the case of Ozark to the Indenture Trustee) as collateral for loans. The impact of FERC Order No. 636 or rejection by Columbia Transmission of these shipper contracts could have an adverse effect on Columbia Gulf's investments and add to the claims against Columbia Transmission. At December 31, 1992, these investments amounted to $25.8 million in Trailblazer, $11.0 million in Ozark, and $3.7 million in Overthrust.

D. Security Holder Litigation. After the announcement on June 19, 1991, regarding the Corporation's probable charge to second quarter earnings and the suspension of the dividend, 17 complaints including purported class actions were filed against the Corporation and its directors and certain officers of the debtor companies in the U.S. District Court of Delaware. The actions, which generally allege violations of certain antifraud provisions of the Securities Act of 1933 and the Securities Exchange Act of 1934, have been consolidated. In addition, three derivative actions were filed in the Court of Chancery in and for New Castle County (Delaware) alleging that directors breached their fiduciary duties. These suits have been stayed by either the Bankruptcy Court filing or by stipulation of the parties. While the Corporation believes that it has meritorious defenses to these actions, the outcome is uncertain at this time.

E. Other Legal Proceedings. The Corporation and its subsidiaries have been named as defendants in various other legal proceedings. In the opinion of management, the ultimate disposition of the currently asserted claims will not have a material adverse impact on the Corporation's consolidated financial position or results of operations.

F. Assets Under Lien. The loans under the debtor-in-possession financing arrangement for the Corporation are given superpriority claim status pursuant to Section 364(c) (1) of the Bankruptcy Code. Loans to the Corporation are secured by either a first or second priority perfected lien on, and security interest in, all property of the Corporation including intercompany loans, other than the voting securities of the Corporation's distribution subsidiaries and Columbia LNG. Columbia Transmission's letter of credit facility is secured by either a first or second priority perfected lien on, and security interest in, all property of Columbia Transmission.

Substantially all of Columbia Transmission's properties have been pledged to the Corporation as security for debt owed by Columbia Transmission to the Corporation. Also, certain customers have made prepayments for gas service which are secured by a pledge of an interest in Columbia Transmission's gas inventory.

G. Cove Point LNG Terminal. Deliveries of liquefied natural gas (LNG) to Columbia LNG's Cove Point, Maryland terminal ceased in April 1980 due to a price dispute between the Algerian LNG supplier and the company from whom Columbia LNG was purchasing the gas.

In 1991, the Corporation entered into a conditional agreement for the sale of its remaining interest in Columbia LNG to Shell LNG Company (Shell LNG), a subsidiary of Shell Oil Company. On July 16, 1992, the Corporation was notified by Shell LNG that it would not proceed with the interim purchase of 40.8 percent of the stock of Columbia LNG. Shell LNG's notification terminates the agreements between the Corporation and Shell LNG for the purchase of the remaining Columbia LNG stock. Shell LNG currently owns 9.2 percent of Columbia LNG's outstanding stock.

Columbia LNG has developed a new business plan to recover its investment in the Cove Point facility. This plan provides for a new peaking and storage service by the end of 1994, as well as a terminalling service for LNG received by tanker. An application with the FERC to charge customers based upon individually-negotiated market rates was filed in February 1993. In accordance with the business plan and in anticipation of the FERC filing, management concluded it is no longer appropriate for Columbia LNG to continue application of SFAS No. 71 and regulatory assets have been removed from Columbia LNG's balance sheet resulting in an extraordinary charge of $60.1 million pre-tax ($39.7 million after-tax) recorded in the third quarter of 1992. The Corporation's investment in Columbia LNG consists of equity securities which are carried at $10.1 million and debt securities bearing an average interest rate of approximately 8 percent which are carried at $41.8 million. The realization of the Corporation's remaining investment in Columbia LNG of $51.9 million will be dependent upon successful implementation of the business plan.

It is estimated that the cost of reactivating the Cove Point Facility will be between $40 million and $55 million depending on whether customers subscribe to the offered terminalling service. Subject to SEC approvals, Columbia LNG expects to finance these costs through project financing, although an equity partner in the project may be considered at a later date.

H. Operating Leases. Payments made in connection with operating leases are charged to operation and maintenance expense as incurred. Such amounts were $57.9 million in 1992, $57.9 million in 1991 and $54.2 million in 1990. Future minimum rental payments required under operating leases that have initial or remaining noncancellable lease terms in excess of one year are:

($ in millions)

1993	15.9
1994	17.8
1995	18.1
1996	17.5
1997	13.8
After	58.2

I. Environmental Matters. The Corporation's subsidiaries are subject to extensive federal, state and local laws and regulations relating to environmental matters. These laws and regulations, which are constantly changing, require expenditures for corrective action at various operating facilities, waste disposal sites and former gas manufacturing sites for conditions resulting from past practices that subsequently were determined to be environmentally unsound.

Certain subsidiaries have received notice from the United States Environmental Protection Agency (EPA) that they are among several parties responsible under federal law for placing wastes at Superfund sites and may be required to share in the cost of remediation for these sites. However, considering known facts, existing laws and possible insurance and rate recoveries, management does not believe the identified Superfund matters will have a material adverse effect on future annual income or on the Corporation's financial position.

The management of the transmission subsidiaries is continuing its own ongoing comprehensive review of compliance with existing environmental standards, including review of past operational activities, through site reviews, identification of potential site problems and formulation of remediation programs where necessary. While the Corporation's transmission subsidiaries have made progress in these ongoing self-assessment programs, because of the thousands of miles of pipeline which they operate, the exceptionally large number of sites at which they conduct or have conducted operations, and the long period over which operations have been conducted, completion of site screenings, characterizations and, if required, site-specific remediations will take a considerable period of time. In addition, the Chapter 11 proceeding of Columbia Transmission adds complexity to addressing environmental issues as some governmental agencies may seek to have their claims resolved in the Bankruptcy Court.

In 1992, Columbia Transmission received a subpoena and information request (Request) from the EPA regarding three major environmental statutes: The Toxic Substances Control Act (TSCA), the Resource Conservation and Recovery Act (RCRA) and the Comprehensive Environmental Response Compensation and Liability Act (CERCLA). The Request relates to Columbia Transmission's past and current environmental practices. Since receipt of the Request, Columbia Transmission has provided the EPA with various materials pursuant to the Request. Columbia Transmission is meeting with the EPA to attempt to resolve the subpoena issues and continues to work cooperatively with environmental officials in the various states in which it operates.

As a consequence of its self-assessment program, Columbia Transmission in recent years recorded projected compliance costs relating to the remediation of low levels of contamination by PCB-based lubricating oils in certain air compressors and other pollutants, including mercury. Further progress by Columbia Transmission in its self-assessment activities resulted in additional pre-tax charges of $65.3 million during 1992. These additional charges relate primarily to: 1) site characterization for pipeline and compressor station operations; 2) other investigatory costs to assess levels of contamination from non-PCB petroleum hydrocarbon occurrence, and other regulated compounds; and 3) changes in established reserves for mercury contamination at certain sites and for low-level PCB contaminations in the compressed air systems. These and other minor adjustments bring Columbia Transmission's recorded net liability to approximately $100 million at December 31, 1992.

As characterization and site-specific activities by Columbia Transmission determine the possible existence, nature and extent of contamination, if any, at several thousand sites and operating facilities and remediation plans are developed, additional charges to earnings will occur. To the extent such plans require approval of federal and/or state authorities, they may be subject to revision. Until assessment progresses further, management lacks sufficient data to predict the magnitude of all required costs. Based on the limited data now available and on various assumptions as to characterization, management believes that annual future expenditures for Columbia Transmission's site investigations, characterization and remediation activities could be at the rate of approximately $20 million per year over the next 10 to 12 years, including costs already accrued. Earnings will continue to be charged appropriately in advance of required expenditures.

The distribution subsidiaries are continuing investigations of certain sites that were once used as manufactured gas plants, which in some instances date back to the mid-1800s. These plants heated certain combustibles in a low-oxygen atmosphere to manufacture low-cost gas for areas where natural gas was not generally available. The process created residues such as coal tar which were typically stored on site prior to being sold for commercial use. However, when the plants were closed and abandoned, this material was simply buried on the plant sites. As time passed, other uses were made of the plant sites and in some cases their identity as a manufactured gas plant was lost. Some of the predecessor companies of the distribution subsidiaries were, or may have been, involved with the ownership and/or the operation of manufactured gas plants. At the present time, management is aware of some plant sites and is investigating certain locations. Management anticipates such investigatory and/or remediation costs will be recovered through rates. Since the Corporation's distribution and other subsidiaries are in the early stages of their respective self-assessment programs, it is likely that additional compliance costs will be identified and become subject to reasonable quantification.

The eventual total cost of full future environmental compliance for the Columbia Gas System is impossible to estimate due to, among other things; (1) the possibility of as yet unknown contamination, (2) the possible effect of future legislation and new environmental agency rules, (3) the possibility of future litigation, (4) the possibility of future designations as a potential responsible party by the EPA and the difficulty of determining liability, if any, in proportion to other responsible parties, (5) possible insurance and rate recoveries, and (6) the effect of possible technological changes relating to future remediation. However, reserves have been established based on information currently available which resulted in a total recorded net liability of $110.9 million for the Columbia Gas System at December 31, 1992. As new issues are identified, appropriate additional liabilities will be recorded.

It is management's continued intent to address environmental issues with the cooperation of regulatory authorities in such a manner as to achieve mutually acceptable compliance plans. However, there can be no assurance that fines and penalties will not be incurred.

Management expects most environmental assessment and remediation costs to be recoverable through rates. Although significant charges to earnings could be required prior to rate recovery, management does not believe that environmental expenditures will have a material adverse effect on the Corporation's financial position, based on known facts, existing laws and regulations and the period over which expenditures are required.

13. Interest Income and Other, Net

Year Ended December 31 ($ in millions)	**1992**	1991	1990
Interest income	**13.2**	17.0	27.8
Condemnation award, including interest	**–**	–	47.9
Gains on sale of interests in subsidiaries	**–**	21.4	–
Impairment of other investments	**(3.6)**	(14.5)	(12.6)
Income from equity investments	**9.3**	5.5	0.9
Miscellaneous	**1.6**	3.0	6.3
Total	**20.5**	32.4	70.3

14. Interest Expense and Related Charges

Year Ended December 31 ($ in millions)	**1992**	1991	1990
Interest on debt	**0.3**	108.3	170.6
Interest on DIP financing	**4.5**	4.1	–
Interest on rate refunds	**3.5**	8.4	10.1
Other interest charges	**5.4**	19.2	0.4
Allowance for borrowed funds used and interest during construction	**–**	(2.6)	(11.3)
Total	**13.7**	137.4	169.8

15. Changes in Components of Working Capital

(excludes cash and temporary cash investments, short-term debt and current maturities of long-term debt)

Year Ended December 31 ($ in millions)	1992	1991	1990
Accounts receivable, net	**114.8**	(60.8)	366.3
Gas inventory	**41.7**	63.1	(164.4)
Accounts and drafts payable	**43.3**	(120.9)	(2.8)
Accrued taxes	**8.3**	70.9	13.3
Estimated rate refunds	**114.4**	9.5	45.0
Estimated supplier obligations	**(3.8)**	67.6	(73.6)
Deferred income taxes	**(1.8)**	(26.5)	(5.1)
Miscellaneous	**(35.5)**	75.7	(44.3)
Change in working capital	**281.4**	78.6	134.4
Reclassifications	**(189.9)**	96.6	(156.8)
Net change in working capital	**91.5**	175.2	(22.4)

16. Business Segment Information

The following tables provide information concerning the Corporation's major business segments. Revenues include intersegment sales to affiliated subsidiaries, which are eliminated when consolidated. Affiliated sales are recognized on the basis of prevailing market or regulated prices. Operating income is derived from revenues and expenses directly associated with each segment. Identifiable assets include only those attributable to the operations of each segment.

($ in millions)		1992	1991	1990
Revenues				
Oil and gas	–Unaffiliated	**184.9**	201.2	195.4
	–Intersegment	**13.8**	13.6	19.6
	Total	**198.7**	214.8	215.0
Transmission	–Unaffiliated	**954.6**	727.3	626.6
	–Intersegment	**532.9**	402.2	316.0
	Total	**1,487.5**	1,129.5	942.6
Distribution	–Unaffiliated	**1,647.6**	1,533.5	1,425.2
	–Intersegment	**–**	–	–
	Total	**1,647.6**	1,533.5	1,425.2
Other energy	–Unaffiliated	**134.9**	114.8	110.7
	–Intersegment	**68.9**	81.7	76.3
	Total	**203.8**	196.5	187.0
Adjustments and eliminations	–Unaffiliated	**–**	–	–
	–Intersegment	**(615.6)**	(497.5)	(411.9)
	Total	**(615.6)**	(497.5)	(411.9)
Consolidated		**2,922.0**	2,576.8	2,357.9

($ in millions)	1992	1991	1990
Operating Income (Loss)			
Oil and gas	**(101.2)**	(4.5)	43.3
Transmission	**129.9**	(1,192.2)	128.2
Distribution	**137.7**	114.9	96.7
Other energy	**6.8**	4.9	5.5
Corporate	**(10.3)**	(9.5)	(11.6)
Consolidated	**162.9**	(1,086.4)	262.1
Depreciation & Depletion			
Oil and gas	**210.0**	130.1	98.5
Transmission	**95.6**	90.4	86.9
Distribution	**57.6**	60.5	59.8
Other energy	**4.9**	4.0	3.6
Consolidated	**368.1**	285.0	248.8
Identifiable Assets			
Oil and gas	**734.9**	871.8	1,010.2
Transmission	**3,922.7**	3,544.9	3,288.9
Distribution	**1,967.3**	1,868.2	1,749.8
Other energy	**124.1**	119.2	140.3
Adjustments and eliminations	**(388.6)**	(344.5)	(55.4)
Corporate and unallocated	**170.5**	272.6	62.5
Consolidated	**6,530.9**	6,332.2	6,196.3
Capital Expenditures			
Oil and gas	**70.8**	120.8	229.0
Transmission	**114.2**	152.9	279.5
Distribution	**99.7**	98.0	107.0
Other energy	**15.0**	10.2	14.1
Consolidated	**299.7**	381.9	629.6

17. Quarterly Financial Data (Unaudited)

Comparing the results of operations between quarters during a year may be misleading in obtaining an understanding of the trend of the System's business operations due to bankruptcy matters, nonrecurring items and seasonal weather patterns which affect earnings and related components of operating revenues and expenses. The total of quarterly amounts for 1991 may not equal annual earnings per share due to increasing shares outstanding.

($ in millions except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
1992				
Operating Revenues	**1,032.2**	**522.1**	**432.2**	**935.5**
Operating Income (Loss)	**21.1**	**54.5**	**(63.0)**	**150.3**
Income (Loss) before Extraordinary Item	**10.8(a)**	**30.7(b)**	**(38.4)(c)**	**87.8(d)**
Extraordinary Item	–	–	**(39.7)**	–
Net Income (Loss)	**10.8**	**30.7**	**(78.1)**	**87.8**
Per Share Amounts				
Earnings (Loss) before Extraordinary Item	**0.21**	**0.61**	**(0.76)**	**1.73**
Extraordinary Item	–	–	**(0.78)**	–
Earnings (Loss) on Common Stock	**0.21**	**0.61**	**(1.54)**	**1.73**
1991				
Operating Revenues	982.4	426.0	378.1	790.3
Operating Income (Loss)	117.0	(1,178.8)	(151.8)	127.2
Income (Loss) before Cumulative Effect of Accounting Changes	47.8(e)	(802.0)(f)	(122.1)(g)	81.5(h)
Cumulative Effect of Accounting Changes	100.4	–	–	–
Net Income (Loss)	148.2	(802.0)	(122.1)	81.5
Per Share Amounts				
Earnings (Loss) before Accounting Changes	0.95	(15.88)	(2.41)	1.61
Changes in Accounting	1.99	–	–	–
Earnings (Loss) on Common Stock	2.94	(15.88)	(2.41)	1.61

(a) Includes a decrease in earnings of $83.4 million to record a writedown in the carrying value of U.S. oil and gas properties, offset by an increase in earnings of $36.8 million relating to not recording interest expense on prepetition debt.

(b) Includes an increase in earnings of $36.0 million relating to not recording interest expense on prepetition debt.

(c) Includes a decrease in earnings of $39.2 million to record a liability for future environmental remediation costs and a decrease in earnings of $24.2 million to record a provision for gas supply charges, offset by an increase in earnings of $36.6 million relating to not recording interest expense on prepetition debt.

(d) Includes an increase in earnings of $39.1 million relating to not recording interest expense on prepetition debt and an improvement of $13.1 million for gas inventory charges collected from customers.

(e) Includes a decrease in earnings of $13.8 million to record a writedown in the carrying value of Canadian oil and gas properties.

(f) Includes a decrease in earnings of $772.0 million to record a provision for gas supply charges, a decrease in earnings of $9.6 million to record a writedown related to certain cogeneration projects and a decrease in earnings of $4.8 million to record a writedown in the carrying value of Canadian oil and gas properties, offset by an increase in earnings of $9.2 million to record a gain on the sale of Columbia Gas of New York, Inc.

(g) Includes a decrease in earnings of $98.7 million to record a provision for gas supply charges, a decrease in income of $14.3 million to record a liability for future environmental remediation costs and a decrease in earnings of $5.4 million to record a writedown in the carrying value of Canadian oil and gas properties, offset by an increase in earnings of $22.3 million relating to not recording interest expense on prepetition debt.

(h) Includes an increase in earnings of $34.2 million relating to not recording interest expense on prepetition debt.

18. Oil and Gas Producing Activities (Unaudited)

Introduction. Reserve information contained in the following tables for the U.S. properties is management's estimate, which was reviewed by the independent consulting firm of Ryder Scott Company Petroleum Engineers. Reserve information for the Canadian properties was supplied by McDaniel & Associates Consultants Ltd. U.S. reserves are reported as net working interest, while Canadian reserves are gross working interest reserves, since royalties related to Canadian leases generally provide for payment on a basis other than a percent of production. Gross revenues are reported after deduction of royalty interest payments.

The Corporation sold its Canadian subsidiary to Anderson Exploration Ltd. of Calgary effective December 31, 1991. Accordingly, the reserve and other information for the Canadian properties is not included in certain tables for 1991 and 1992.

Capitalized Costs	United States			Canada			Total		
($ in millions)	**1992**	1991	1990	**1992**	1991(b)	1990	**1992**	1991(b)	1990
Capitalized Costs at Year End									
Proved properties	**1,111.5**	1,086.9	1,041.4	**–**	–	232.6	**1,111.5**	1,086.9	1,274.0
Unproved properties(a)	**78.9**	80.7	89.3	**–**	–	27.6	**78.9**	80.7	116.9
Total capitalized costs	**1,190.4**	1,167.6	1,130.7	**–**	–	260.2	**1,190.4**	1,167.6	1,390.9
Accumulated depletion	**(602.1)**	(441.3)	(422.0)	**–**	–	(118.8)	**(602.1)**	(441.3)	(540.8)
Net capitalized costs	**588.3**	726.3	708.7	**–**	–	141.4	**588.3**	726.3	850.1
Costs Capitalized During Year									
Acquisition									
Proved properties	**0.2**	–	29.4	**–**	–	0.3	**0.2**	–	29.7
Unproved properties	**4.6**	6.4	13.2	**–**	–	3.3	**4.6**	6.4	16.5
Exploration	**25.8**	32.8	53.3	**–**	–	13.6	**25.8**	32.8	66.9
Development	**39.7**	62.9	100.4	**–**	–	14.6	**39.7**	62.9	115.0
Costs capitalized	**70.3**	102.1	196.3	**–**	–	31.8	**70.3**	102.1	228.1

(a) Represents expenditures associated with properties on which evaluations have not been completed.

(b) Due to the sale of the Canadian subsidiary, no information is provided for costs capitalized by that subsidiary throughout 1991.

Historical Results of Operations	United States			Canada			Total		
($ in millions)	**1992**	1991	1990	**1992**	1991	1990	**1992**	1991	1990
Gross revenues									
Unaffiliated	**183.9**	181.8	179.4	**–**	15.7	15.6	**183.9**	197.5	195.0
Affiliated	**13.2**	14.1	18.9	**–**	–	–	**13.2**	14.1	18.9
Production costs	**50.5**	41.6	36.0	**–**	5.6	4.3	**50.5**	47.2	40.3
Depletion	**209.4(b)**	82.1	68.1	**–**	47.1(a)	30.0(a)	**209.4(b)**	129.2	98.1
Income tax expense	**(25.0)**	22.8	31.2	**–**	(12.6)	(6.4)	**(25.0)**	10.2	24.8
Results of operations	**(37.8)**	49.4	63.0	**–**	(24.4)	(12.3)	**(37.8)**	25.0	50.7

Results of operations for producing activities exclude administrative and general costs, corporate overhead and interest expense.
Income tax expense is expressed at statutory rates less Section 29 credits.

(a) Includes writedown of the carrying value of $36.4 million for 1991 and $22.6 million for 1990.

(b) Includes writedown of the carrying value of $126.4 million for 1992.

Other Oil and Gas Production Data

	United States			Canada		
	1992	1991	1990	**1992**	1991	1990
Average sales price per Mcf of gas ($)	**2.02**	1.88	2.03	**–**	1.02	1.21
Average sales price per barrel of oil and other liquids ($)	**18.20**	22.18	24.13	**–**	15.83	18.69
Production (lifting) cost per dollar of gross revenue ($)	**0.26**	0.21	0.18	**–**	0.36	0.28
Depletion rate per dollar of gross revenue ($)	**0.42**	0.42	0.34	**–**	–	–
Depletion rate per equivalent Mcf ($)	**–**	–	–	**–**	1.10	1.09

Reserve Quantity Information

	United States		Canada(a)	
Proved Reserves	Gas (Bcf)	Oil and Other Liquids (000 Bbls)	Gas (Bcf)	Oil and Other Liquids (000 Bbls)
Reserves as of December 31, 1989	791.0	11,968	111.7	4,763
Revisions of previous estimate	22.3	1,936	(2.1)	(206)
Extensions, discoveries and other additions	59.9	1,797	16.8	749
Production	(72.3)	(2,057)	(3.0)	(631)
Purchase/(sale) of minerals-in-place	11.6	1,097	(10.2)	(425)
Reserves as of December 31, 1990	812.5	14,741	113.2	4,250
Revisions of previous estimate	14.2	(854)	–	–
Extensions, discoveries and other additions	62.7	4,514	–	–
Production	(70.1)	(2,833)	(6.2)	(578)
Purchase/(sale) of minerals-in-place	(11.2)	–	(107.0)	(3,672)
Reserves as of December 31, 1991	808.1	15,568	–	–
Revisions of previous estimate	**(9.1)**	**(946)**	**–**	**–**
Extensions, discoveries and other additions	**51.3**	**3,089**	**–**	**–**
Production	**(69.2)**	**(3,061)**	**–**	**–**
Purchase/(sale) of minerals-in-place	**(1.6)**	**–**	**–**	**–**
Reserves as of December 31, 1992	**779.5**	**14,650**	**–**	**–**
Proved developed reserves as of December 31				
1990	730.1	11,210	113.2	4,250
1991	697.7	13,338	–	–
1992	**664.4**	**13,143**	**–**	**–**

(a) Gross working-interest reserves.

Standardized Measure of Discounted Future Net Cash Flows

	United States			Canada			Total		
($ in millions)	**1992**	1991	1990	**1992**	1991	1990	**1992**	1991	1990
Future cash inflows	**2,568.9**	2,152.3	2,420.2	**–**	–	226.4	**2,568.9**	2,152.3	2,646.6
Future production costs	**(562.3)**	(511.9)	(508.8)	**–**	–	(61.1)	**(562.3)**	(511.9)	(569.9)
Future development costs	**(162.9)**	(157.8)	(165.4)	**–**	–	(12.2)	**(162.9)**	(157.8)	(177.6)
Future income tax expense	**(546.4)**	(411.6)	(514.3)	**–**	–	(29.3)	**(546.4)**	(411.6)	(543.6)
Future net cash flows	**1,297.3**	1,071.0	1,231.7	**–**	–	123.8	**1,297.3**	1,071.0	1,355.5
Less 10% discount	**636.2**	504.0	562.0	**–**	–	46.5	**636.2**	504.0	608.5
Standardized measure of discounted future net cash flows	**661.1**	567.0	669.7	**–**	–	77.3	**661.1**	567.0	747.0

Future cash inflows are computed by applying year-end prices to estimated future production of proved oil and gas reserves. Future expenditures (based on year-end costs) represent those costs to be incurred in developing and producing the reserves. Discounted future net cash flows are derived by applying a 10% discount rate, as required by the Financial Accounting Standards Board, to the future net cash flows. This data is not intended to reflect the actual economic value of the Corporation's oil and gas producing properties or the true present value of estimated future cash flows since many arbitrary assumptions are used. The data does provide a means of comparison among companies through the use of standardized measurement techniques.

A reconciliation of the components resulting in changes in the standardized measure of discounted cash flows attributable to proved oil and gas reserves for the three years ending December 31, 1992, follows:

	United States			Canada			Total		
($ in millions)	**1992**	1991	1990	**1992**	1991*	1990	**1992**	1991*	1990
Beginning of year	**567.0**	669.7	593.0	**–**	–	70.5	**567.0**	669.7	663.5
Oil and gas sales, net of production costs	**(146.6)**	(154.3)	(162.3)	**–**	–	(11.3)	**(146.6)**	(154.3)	(173.6)
Net changes in prices and production costs	**210.4**	(140.0)	(11.6)	**–**	–	6.1	**210.4**	(140.0)	(5.5)
Change in future development costs	**(5.1)**	7.6	(25.5)	**–**	–	1.1	**(5.1)**	7.6	(24.4)
Extensions, discoveries and other additions, net of related costs	**81.0**	84.4	109.8	**–**	–	11.4	**81.0**	84.4	121.2
Revisions of previous estimates, net of related costs	**(18.0)**	8.9	35.7	**–**	–	(2.3)	**(18.0)**	8.9	33.4
Purchases (sales) of reserves	**(2.4)**	(15.8)	30.3	**–**	–	–	**(2.4)**	(15.8)	30.3
Accretion of discount	**76.9**	93.5	84.4	**–**	–	8.6	**76.9**	93.5	93.0
Net change in income taxes	**(61.3)**	64.4	(14.5)	**–**	–	(2.4)	**(61.3)**	64.4	(16.9)
Timing of production and other changes	**(40.8)**	(51.4)	30.4	**–**	–	(4.4)	**(40.8)**	(51.4)	26.0
End of year	**661.1**	567.0	669.7	**–**	–	77.3	**661.1**	567.0	747.0

*Due to the sale of Canadian properties on December 31, 1991, no reconciliation of future net cash flows related to Canadian properties is supplied.

The estimated discounted future net cash flows increased during 1992 primarily due to net changes in prices and production costs and new additions. The standardized measure of the Corporation's oil and gas properties can be influenced by affiliated and unaffiliated pipeline transportation rate design (which is presently being evaluated as part of the FERC Order No. 636).

Directors

Thomas S. Blair
A director since 1962, Thomas Blair is chairman of Blair Strip Steel Company, a manufacturer of cold-rolled strip steel in New Castle, Pennsylvania. He also serves as a director of Tuscarora Incorporated.

Committee Memberships: Compensation, Executive and Finance

John H. Croom
John Croom has been chairman, president and chief executive officer of the Columbia Gas System since 1984. He was elected to the board in 1981. Mr. Croom is a director of the National Petroleum Council and a director and former board chairman of the Gas Research Institute and served as a director and first vice chairman of the American Gas Association.

Committee Chairman: Executive

John D. Daly
John Daly was elected executive vice president of the Columbia Gas System and a director in September 1990. He is a former chairman of the Interstate Natural Gas Association of America.

Dr. Sherwood L. Fawcett
A director since 1984, Dr. Fawcett is chairman of the board of Transmet Corporation of Columbus, Ohio, a producer of rapidly solidified metals. He is a director of Sedum Corporation and Research Dynamics Inc.; and retired chairman of the board of trustees and chief executive officer of Battelle Memorial Institute.

Committee Memberships: Audit and Compensation

Robert H. Hillenmeyer
Robert Hillenmeyer was elected to the board in 1970. He is the former chairman and chief executive officer of Hillenmeyer Nurseries, Inc. He also serves as a director of GTE South.

Committee Memberships: Audit, Executive and Finance

Malcolm T. Hopkins
A director since 1982, Malcolm Hopkins was vice chairman, chief financial officer and a director of the former St. Regis Corporation. Since 1984 he has been a private investor. Mr. Hopkins currently serves as a director of Metropolitan Series Fund, Inc. and MetLife Portfolios, Inc.; MAPCO Inc.; Wangner Systems Corporation; KinderCare Learning Centers Inc.; and as a trustee of The Biltmore Funds.

Committee Memberships: Compensation and Executive
Committee Chairman: Finance

W. Frederick Laird
Frederick Laird retired as chairman of the board and chief executive officer of the Columbia Gas System in 1984. He has been a director since 1974. He also serves as a director of Wilmington Trust Company.

Committee Membership: Executive

Dr. William E. Lavery
Dr. Lavery was elected to Columbia's board in 1985. He is president emeritus and professor of international affairs at Virginia Polytechnic Institute and State University in Blacksburg, Virginia. He also serves as a director of Dominion Bankshares Corporation and Shenandoah Life Insurance Company.

Committee Memberships: Audit and Finance

George P. MacNichol, III
George MacNichol was elected to the board in 1971. A retired officer and director of the Libbey-Owens-Ford Company, he has been a private investor since 1979.

Committee Memberships: Compensation and Finance

Robert A. Oswald
Robert Oswald has been executive vice president and chief financial officer of the Columbia Gas System since 1989. He was elected to the board in 1987.

Ernesta G. Procope
A director since 1979, Ernesta Procope is president and chief executive officer of E. G. Bowman Co., Inc., a commercial insurance brokerage firm in New York City. She also serves as a director of Avon Products, Inc. and Chubb Corporation.

Committee Memberships: Audit and Compensation

Dr. Ronald W. Skeddle
Dr. Skeddle was elected to the board in 1989. He has been president and chief executive officer of Libbey-Owens-Ford Company, glass manufacturers, in Toledo, Ohio, since 1986. Dr. Skeddle also serves as a director of Cooper Tire and Rubber Company and Federal Mogul Corporation

Committee Memberships: Audit and Finance

James R. Thomas II
Elected to the board in 1990, James Thomas has been a private investor since 1983. He was president and chief executive officer of Carbon Industries, Inc. from 1974 to 1982. Mr. Thomas is also on the board of directors of One Valley Bank, N.A.; Camcare, Inc.; and Shoney's, Inc.

Committee Membership: Finance
Committee Chairman: Audit

William R. Wilson
William Wilson, a director since 1987, retired as chairman and chief executive officer of Lukens Inc., manufacturer of steel and industrial products, in December 1991. He also serves as director of Acme Metals Incorporated and Provident Mutual Life Insurance Company.

Committee Membership: Audit
Committee Chairman: Compensation

THE COLUMBIA GAS SYSTEM, INC.

Officers

John H. Croom
Chairman, President and Chief Executive Officer

John D. Daly
Executive Vice President

Robert A. Oswald
Executive Vice President
and Chief Financial Officer

Daniel L. Bell, Jr.
Senior Vice President, Chief Legal Officer
and Secretary

Michael W. O'Donnell
Senior Vice President and
Assistant Chief Financial Officer

Richard A. Casali
Vice President

Richard E. Lowe
Vice President and Controller

Larry J. Bainter
Treasurer

Tejinder S. Bindra
Joyce Koria Hayes
James B. Lange
Assistant Secretaries

Columbia Gas System Service Corporation

John H. Croom
Chairman, President and Chief Executive Officer

John D. Daly
Executive Vice President

Robert A. Oswald
Executive Vice President
and Chief Financial Officer

Operating Company Executives

OIL AND GAS COMPANIES

Columbia Gas Development Corporation
John P. Bornman, Jr.
President

Columbia Natural Resources, Inc.
John R. Henning
President and Chief Executive Officer

TRANSMISSION COMPANIES

Columbia Gas Transmission Corporation
Columbia Gulf Transmission Company
James P. Holland
Chairman and Chief Executive Officer

R. Larry Robinson
President

Mark P. O'Flynn
Senior Vice President and Chief Financial Officer

Columbia LNG Corporation
L. Michael Bridges
President

DISTRIBUTION COMPANIES

Columbia Gas of Kentucky, Inc.
Columbia Gas of Maryland, Inc.
Columbia Gas of Ohio, Inc.
Columbia Gas of Pennsylvania, Inc.
Commonwealth Gas Services, Inc.
C. Ronald Tilley
Chairman and Chief Executive Officer

James R. Lee
Executive Vice President

Robert C. Skaggs, Jr.
Executive Vice President

Richard J. Gordon
President and Chief Operating Officer
Columbia Gas of Kentucky and Ohio

Thomas E. Harris
President and Chief Operating Officer
Commonwealth Gas Services, Inc.

Gary J. Robinson
President and Chief Operating Officer
Columbia Gas of Maryland and Pennsylvania

OTHER ENERGY COMPANIES

Columbia Atlantic Trading Corporation
L. Michael Bridges
President

Columbia Coal Gasification Corporation
John R. Henning
President and Chief Executive Officer

Columbia Propane Corporation
Commonwealth Propane, Inc.
A. Mason Brent
President

The Inland Gas Company, Inc.
Logan W. Wallingford
President

TriStar Capital Corporation
William F. Morse
President

TriStar Ventures Corporation
Bartholomew F. Cranston
President

Common Stock
The common stock of The Columbia Gas System, Inc., is traded on the New York Stock Exchange under the ticker symbol CG and abbreviated as either ColumGas or ColGs in trading reports. The number of shareholders of record on December 31, 1992, was approximately 72,000. Columbia's fiscal year is from January 1 to December 31.

10-K Report Requests
Copies of Columbia's Form 10-K and Form 10-Q reports to the Securities and Exchange Commission and a supplementary report containing more detailed operational, financial and statistical data are available at no charge by writing to Columbia's Investor Relations Department.

Transfer Agents and Registrars
Harris Trust Company of New York
Corporate Trust Department
77 Water Street, 4th Floor
New York, NY 10005
(212) 701-7600

Debenture Trustee
Marine Midland Bank, N.A.
140 Broadway, 12th Floor
New York, NY 10015
(212) 658-6524

Debenture Paying Agent and Registrar
Morgan Guaranty Trust Company of New York
Security Holder Relations
15 Broad Street
New York, NY 10260-0023
(212) 235-0900

Common Stock Data
The Columbia Gas System, Inc.

Year	Number of Shares Traded (000)	Market Price High $	Market Price Low $
1992	**35,488**	**23 7/8**	**14**
1991	82,756	47 1/2	12 7/8
1990	31,777	54 3/4	41 1/2
1989	39,132	52 3/4	33 3/4
1988	47,906	44 3/4	26 7/8
1987	31,491	56 1/2	35 1/2
1986	26,311	46	34 3/4
1985	29,135	40	26 3/4
1984	14,624	37 1/2	27
1983	14,191	35 1/2	27 7/8

Annual Meeting
Columbia's 1993 Annual Stockholders' Meeting will be held at 1 p.m. (EDT) on Thursday, April 29, in the duBarry Room of the Hotel du Pont, 11th and Market Streets, Wilmington, Del. Proxy material will be mailed on or about March 8, 1993. Columbia will include a report of significant business conducted at the meeting in its first 1993 quarterly report to shareholders.

Dividend Reinvestment Plan
Even though Columbia suspended its dividend in 1991, the Corporation continues to offer shareholders of record a convenient method to acquire additional shares of common stock through optional cash payments to its Dividend Reinvestment Plan. If you elect to discontinue participation, you may receive either a stock certificate or cash for shares credited to your account. There is a small brokerage commission on shares purchased or sold through the Plan. A complete Plan description is available by writing Columbia's Shareholder Services Department.

Communicating with Columbia

Mailing Addresses:
The Columbia Gas System, Inc.
20 Montchanin Road
Wilmington, DE 19807-0020

or

The Columbia Gas System, Inc.
Shareholder Services Department
P.O. Box 2318
Columbus, OH 43216-2318

Telephone Inquiries:
(8:00 a.m.–4:45 p.m. Eastern time)

Main Telephone: (302) 429-5000

Corporate Communications:
(302) 429-5262

Corporate Secretary: (302) 429-5349

Investor Relations: (302) 429-5331

Shareholder Services:
(800) 245-4588 or (614) 481-1000

Facsimile: (302) 429-5730

Shareholder Information Service (Recorded):
(800) 321-1449

Glossary

Bbls Barrels. One barrel is the equivalent of 42 standard U.S. gallons.

Bcf Billion cubic feet. A common unit of measurement of natural gas.

Bypass When end users access natural gas supplies without using local distribution company facilities.

Chapter 11 A provision of federal bankruptcy law that protects a company from its creditors and allows the business to continue to operate while a plan of reorganization is completed. Debtor and creditors are allowed considerable flexibility in working out a reorganization plan.

Cogeneration A process that produces electrical and thermal energy simultaneously from a single fuel source, often natural gas.

Degree Day A measure of how cold the weather is. A degree day is calculated by subtracting the mean daily outdoor temperature from 65°F. Degree days would total 25 at a mean temperature of 40°F. The colder the weather, the greater the number of degree days.

Dekatherm A measure of heating value equal to one million British thermal units. One dekatherm is roughly equivalent to one thousand cubic feet of natural gas (one Mcf) in heating value.

Development Well A well drilled into a known producing formation in a previously discovered field.

Distribution Company A natural gas utility that sells gas directly to consumers under the jurisdiction of a state regulatory agency.

Electronic Measurement A computer-based technology that calculates natural gas volumes instantaneously based on the pressure and temperature of gas flowing through a measurement station.

Exploratory Well A well drilled to a previously untested geologic structure to determine the presence of oil or gas.

Federal Energy Regulatory Commission (FERC) The federal agency that, among other functions, regulates all interstate natural gas pipelines and some intrastate gas operations.

Firm Service Service offered to customers that anticipates no interruptions other than from unexpected or uncontrollable events.

Futures Contracts Contracts that obligate the seller to deliver and the buyer to purchase a commodity at a fixed price at a specified date.

Gross Acres/Wells Total acreage or the total number of wells in which a company holds participating interests.

Hedging The process of reducing financial exposure to adverse natural gas, oil or propane price movements.

Horizontal Drilling Drilling that deviates from the vertical and exposes a greater portion of the underground producing rock formation to the well bore than would occur with a vertical well. Horizontal drilling generally improves the well's productivity.

Integrated Resource Planning Programs designed to integrate demand options with supply alternatives to create a mix that satisfies customers' long- and short-term needs at the lowest cost.

Interruptible Service A service offered to customers that anticipates and permits interruptions on short notice.

Liquefied Natural Gas (LNG) Natural gas that is converted to a liquid state by reducing its temperature to minus 260°F at atmospheric pressure.

Market-sensitive Contract A contract whose pricing and sales terms can be adjusted to reflect changes in supply and demand conditions in the marketplace.

MBbls Thousand barrels.

Mcf Thousand cubic feet. The most common measurement of gas volume.

Merchant Function (See Sales Service.)

MMcf Million cubic feet.

Net Acres/Net Wells A company's share of the total acreage or number of wells in which it has participating interests.

Normal Weather The average of 30 years of historic weather data compiled by the National Weather Service.

Order 636 Commonly called the FERC restructuring rule. Issued in April 1992, this order culminates FERC's efforts to make the natural gas industry more competitive.

Propane A heavier-than-air gaseous hydrocarbon found with crude petroleum and natural gas.

Proved Reserves Oil, gas or coal that has been discovered and determined to be recoverable but is still in the ground.

Regulatory Lag When existing rates do not adequately reflect the current level of operating costs, investment or throughput.

Reorganization Plan The document that outlines how a business will be restructured to permit its emergence from Chapter 11 of the U.S. Bankruptcy Code.

Sales Service Traditional service agreements under which gas pipeline companies purchase gas from suppliers for resale to customers.

Short-haul Transportation A gas transportation service provided by Columbia Gulf Transmission Co. over short distances along its pipeline system.

Spot Market Sales Short-term direct sales, generally 30 days or less, of natural gas, crude oil or refined petroleum products by producers or brokers to others.

Take-or-Pay Costs Charges incurred by pipelines when they do not take the minimum quantities of natural gas specified under purchase contract terms.

Throughput Total volumes of gas delivered.

Transportation Service Service agreements under which pipelines transport gas supplies that customers purchase directly from third parties.

Unbundled Services Separating pipeline services, such as storage, gathering or transmission, and charging separate rates that reflect the costs of each.

Underground Storage A service that permits the injection of large quantities of natural gas into underground rock formations during periods of low market demand and withdrawal during periods of peak market demand.

COLUMBIA GAS
System

20 Montchanin Road
Wilmington, Delaware
19807-0020

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