National Fuel Gas Company

SINCE 1902

2002

ANNUAL REPORT

AND FORM 10-K

Corporate Profile

National Fuel Gas Company, incorporated in 1902, is a diversified energy company with its headquarters in Buffalo, New York. The Company's $3.4 billion in assets is distributed among six principal business segments: Exploration and Production, Pipeline and Storage, Utility, Timber, Energy Marketing and International.

National Fuel's history dates from the earliest days of the natural gas and oil industry in the United States, and the Company has been responsible for many industry firsts. Today, the Company continues to be managed in the same innovative and entrepreneurial spirit, and takes pride in its 100-year tradition of delivering service and value.

Exploration and Production *Seneca Resources Corporation* explores for, develops and purchases natural gas and oil reserves in the Gulf Coast region of Texas and Louisiana, the Appalachian region, the Rocky Mountain region, California and the western provinces of Canada. Currently, Seneca's exploration emphasis is centered around new reserves in Canada and Appalachia, while development drilling continues to expand in California.

Pipeline and Storage *National Fuel Gas Supply Corporation* provides interstate natural gas transportation and storage for affiliated and nonaffiliated companies through an integrated gas pipeline system that extends 2,910 miles from southwestern Pennsylvania to the New York-Canadian border at the Niagara River. It also owns 28 underground natural gas storage areas and is co-owner of four others.

Utility *National Fuel Gas Distribution Corporation* sells or transports natural gas to over 732,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The major areas served by this system include Buffalo, Niagara Falls and Jamestown in New York, and Erie and Sharon in Pennsylvania.

Timber *Highland Forest Resources, Inc.* and *Seneca Resources Corporation, Northeast Division* carry out the Timber segment operations for the Company. Highland operates three sawmills in northwestern Pennsylvania. Seneca markets timber from its New York and Pennsylvania land holdings.

Energy Marketing *National Fuel Resources, Inc.* markets natural gas to industrial, commercial, public authority and residential end-users in western and central New York and northwestern Pennsylvania, offering competitively priced energy and energy management services to its customers.

International *Horizon Energy Development, Inc.* engages in foreign energy projects through the investments of its indirect subsidiaries as the sole or substantial owner of various business entities. In addition to assets in the Czech Republic, joint development agreements have been signed with partners in Bulgaria and Italy.

CONTENTS

Highlights

Year Ended September 30	2002	2001	2000	1999	1998
Operating Revenues *(Thousands)*	**$1,464,496**	$2,059,836	$1,412,416	$1,254,402	$1,248,000
Net Income Available for Common Stock *(Thousands)*	**$ 117,682**	$ 65,499	$ 127,207	$ 115,037	$ 23,188
Net Income Available for Common Stock Before Special Items *(Thousands)*	**$ 127,541**[1]	$ 169,539[2]	$ 127,207	$ 115,037	$ 111,418[4]
Return on Average Common Equity[5]	**11.2%**	6.4%	13.0%	12.6%	2.6%
Return on Average Common Equity Before Special Items[5]	**12.1%**[1]	15.8%[2]	13.0%	12.6%	11.9%[4]
Per Common Share					
Basic Earnings	**$ 1.47**	$ 0.83	$ 1.63	$ 1.49	$ 0.30
Diluted Earnings	**$ 1.46**	$ 0.82	$ 1.61	$ 1.47	$ 0.30
Basic Earnings Before Special Items	**$ 1.59**[1]	$ 2.14[2]	$ 1.63	$ 1.49	$ 1.45[4]
Diluted Earnings Before Special Items	**$ 1.58**[1]	$ 2.11[2]	$ 1.61	$ 1.47	$ 1.44[4]
Dividends Paid	**$ 1.02**	$ 0.97	$ 0.94	$ 0.91	$ 0.88
Dividend Rate at Year-End	**$ 1.04**	$ 1.01	$ 0.96	$ 0.93	$ 0.90
Book Value at Year-End	**$12.54**	$12.63	$12.55	$12.09	$11.57
Common Shares Outstanding at Year-End	**80,264,734**	79,406,105	78,659,606	77,674,998	76,937,590
Weighted Average Common Shares Outstanding					
Basic	**79,821,430**	79,053,444	78,233,842	77,327,962	76,632,794
Diluted	**80,534,453**	80,361,258	79,166,200	78,083,456	77,407,052
Average Common Shares Traded Daily	**180,675**	222,308	161,271	121,327	125,482
Common Stock Price					
High	**$25.70**	$32.25	$29.41	$25.00	$24.56
Low	**$15.61**	$21.96	$19.69	$18.75	$19.81
Close	**$19.87**	$23.03	$28.03	$23.59	$23.50
Net Cash Provided by Operating Activities *(Thousands)*	**$ 345,550**	$ 414,027	$ 238,246	$ 267,504	$ 249,863
Total Assets *(Thousands)*	**$3,401,309**	$3,445,231	$3,251,031	$2,842,586	$2,684,459
Expenditures for Long-Lived Assets *(Thousands)*	**$ 232,904**	$ 385,103	$ 398,777	$ 265,527	$ 507,537
Volume Information					
Utility Throughput-MMcf					
Gas Sales	**101,444**	104,186	97,617	101,675	108,599
Gas Transportation	**61,909**	66,283	71,862	64,086	60,080
Pipeline & Storage Throughput-MMcf					
Gas Transportation	**297,822**	321,555	313,548	308,303	313,048
Production Volumes					
Gas-MMcf	**41,454**	41,004	41,670	37,166	36,474
Oil-Mbbl	**7,662**	7,857	5,147	4,016	2,614
Total-MMcfe	**87,426**	88,146	72,552	61,262	52,161
Proved Reserves					
Gas-MMcf	**258,221**	322,380	301,667	320,792	325,065
Oil-Mbbl	**99,717**	115,328	119,697	75,819	66,591
Total-MMcfe	**856,523**	1,014,348	1,019,849	775,706	724,611
Energy Marketing Volumes-MMcf					
Gas	**33,042**	36,753	35,465	34,454	26,453
International Sales Volumes					
Heating (Gigajoules)	**8,689,887**	9,978,118	10,222,024	10,047,042	7,116,776
Electricity (Megawatt hours)	**972,832**	1,019,901	1,147,303	1,138,980	763,848
Average Number of Utility Retail Customers	**680,489**	678,357	656,792	691,080	702,283
Average Number of Utility Transportation Customers	**51,729**	54,140	78,610	41,515	28,224
Number of Employees at September 30	**3,177**[3]	3,235[3]	3,597[3]	3,807[3]	3,944[3]

(1) Excludes impairment of investment in partnership of ($9.9) million or ($0.12) per common share (basic and diluted).
(2) Excludes oil and gas asset impairment of ($104.0) million or ($1.32) per common share (basic) and ($1.29) per common share (diluted).
(3) Includes 944, 991, 1,201, 1,406 and 1,390 international employees at September 30, 2002, 2001, 2000, 1999 and 1998, respectively.
(4) Excludes oil and gas asset impairment of ($79.1) million or ($1.03) per common share (basic) and ($1.02) per common share (diluted) and Cumulative Effect of Change in Accounting of ($9.1) million or ($0.12) per common share (basic and diluted).
(5) Calculated using Total Common Shareholder Equity Before Items of Other Comprehensive Income (Loss).

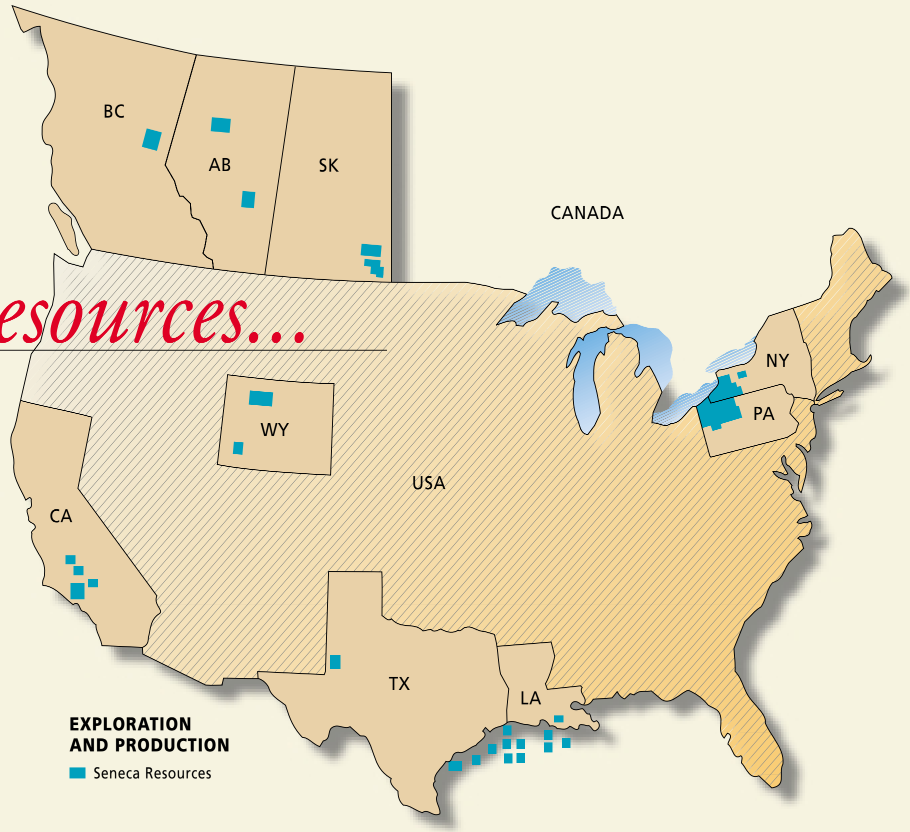
1902

The history of National Fuel Gas Company is a vital chapter in the chronicle of the natural gas industry. Since the first public use of natural gas in Fredonia, New York in 1821, natural gas entrepreneurs advanced an industry destined to become one of the largest in the United States.

In 1886, Standard Oil interests in Buffalo and western Pennsylvania elected to put many of their natural gas investments under the Natural Gas Trust. That collection of investments became the initial assets of National Fuel shortly after the company was incorporated in New Jersey on December 8, 1902.

2002 At a Glance

...developing resources...



IN 2002:

Exploration and Production

- Net income of $26.9 million or $0.33 per diluted share.
- Production was 87.4 Bcfe, nearly flat compared to last year's production of 88.1 Bcfe.
- Continued changing emphasis from offshore exploration to onshore production.

Timber

- Net income of $9.7 million or $0.12 per diluted share.
- Increased production nearly 14% to 31.8 million board feet.

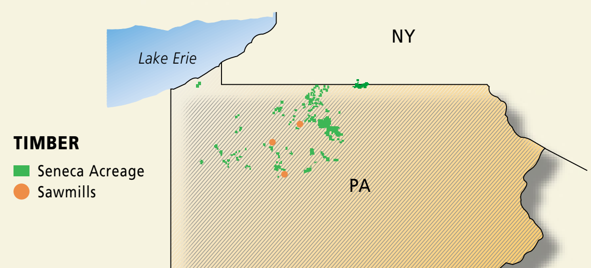
OUTLOOK:*

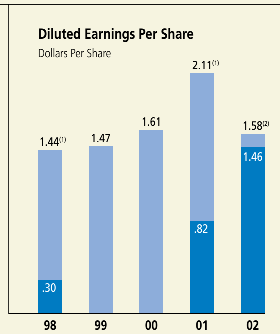
Exploration and Production

- Production goal of 80 to 85 Bcfe reflects ongoing transition from Gulf of Mexico; natural gas production emphasized for 2003.
- Capital budget of $82 million, excluding acquisitions, includes plans to drill over 200 onshore wells.
- Long-range plans include increasing reserves and production, controlling expenditures and reducing risk.

Timber

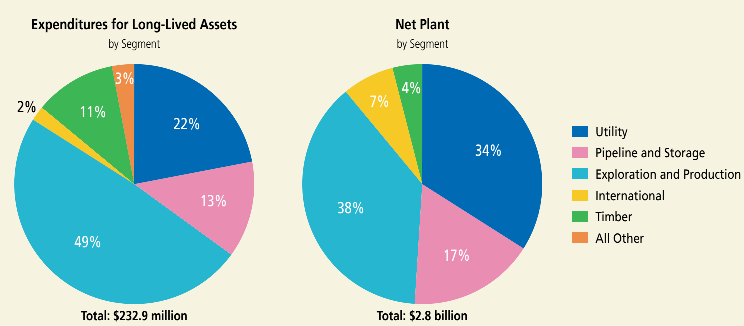
- Continue to monetize assets, including increased production, and sales or purchases of timber.





(1) Excludes special items for impairment of oil and gas producing assets in 1998 and 2001 and for cumulative effect of change in accounting in 1998.

(2) Excludes impairment of investment in partnership in 2002.



All references to years in this Annual Report are to the Company's fiscal year, which ends September 30.

...delivering energy...

IN 2002:

Pipeline and Storage

- Net income of $39.6 million or $0.49 per diluted share, exclusive of the third quarter write down of the Independence Pipeline Project. Including the write down, net income of $29.7 million or $0.37 per diluted share.
- Announced intent to acquire Empire State Pipeline for $240 million; closing expected in early 2003.
- Pursued Northwinds Pipeline project with our partner TransCanada PipeLines Limited.

International

- Net loss of $4.4 million or $0.06 per diluted share resulted from higher operation and maintenance expenses related to European power development projects.

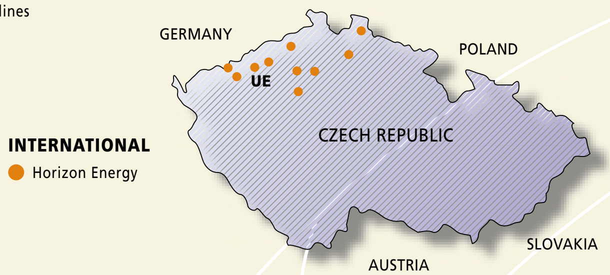
OUTLOOK:*

Pipeline and Storage

- Develop expansion plans for Empire State Pipeline including connections to nearby storage fields, other utilities and other interstate pipelines.
- Continue plans to increase storage field deliverability and capacity through reconditioning wells and replacing storage lines.
- Pursue projects which will improve the infrastructure needed to meet future energy needs.

International

- Continue to pursue opportunities to develop electric generation projects in Italy and Bulgaria.



...serving customers...

IN 2002:

Utility

- Net income of $49.5 million or $0.62 per diluted share.
- Installed two residential distributed generation systems at sites in western New York.
- Launched integrated communication program to promote awareness and understanding of Customer Choice of natural gas suppliers.

Energy Marketing

- Net income of $8.6 million or $0.11 per diluted share.
- Improved operational strategies employed by new management team contributed to dramatic turnaround in earnings.

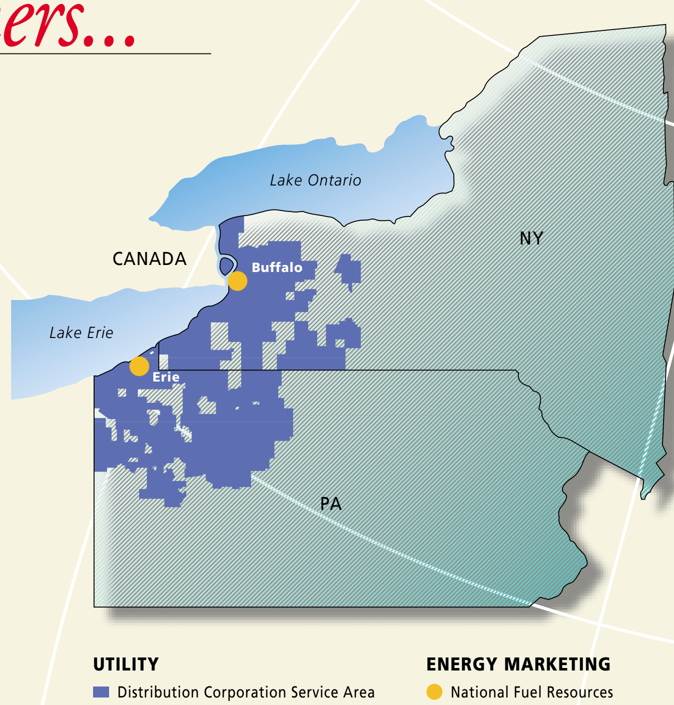
OUTLOOK:*

Utility

- Continue to promote distributed generation opportunities throughout our service territories.
- Maintain excellent customer service levels.
- Broaden promotion programs for residential Customer Choice awareness.

Energy Marketing

- Maintain focus on core market, margin protection and risk management efforts to remain profitable.



To Our Shareholders:

This is the dawn of National Fuel Gas Company's second century as an integrated natural gas company. National Fuel was incorporated on December 8, 1902 and much has changed during our first century. But there have been two constants to guide us—the integrity of our people and the demand for natural gas. During these last 100 years, the unceasing commitment to employ quality people and provide a quality product has enabled National Fuel to create total earnings of about $2.0 billion and to pay total dividends of about $1.4 billion. As I write this, my first letter as Chairman of your Company, I am shocked and dismayed at the recent breaches of trust by the executives of so many companies in corporate America, but I am buoyed by National Fuel's commitment to an unwavering focus on certain fundamentals. This has enabled us to survive not only today's trouble and turbulence in the energy industry, but also two World Wars and the Great Depression. These fundamentals include stability, reliability, safety, real assets, real products, real services, real earnings and real cash returns.

This year's earnings of $1.58 per share (excluding the write down associated with the Independence Pipeline), while substantially below last year's record earnings of $2.11 per share (excluding the impairment associated with the oil and gas assets), were well within the range of guidance provided to the financial community at the beginning of the year of $1.50 to $1.60 per share. This is a gratifying performance in light of significantly lower prices for oil and gas, and the warmer winter weather we experienced.

In addition to earnings, we believe in dividends. In our 100 years, we have paid a dividend every year. For the last 32 years, your Board of Directors has increased the annual dividend rate, which is currently $1.04 per share, and we expect the Board will continue that tradition.* Meeting that dividend further makes us accountable and responsible to you, our shareholders, and is tangible evidence of the reality of our numbers.

The bedrocks of your Company, the Utility and Pipeline and Storage segments, continued to deliver stable and consistent performance just as they have in the past and as we expect them to in the future.* Their combined earnings per share were $1.11 (excluding the Independence Pipeline write down) in 2002 compared to combined earnings of $1.26 in 2001. The Utility segment was particularly impacted by the effect of warmer weather in Pennsylvania, where we do not have a weather normalization clause, and reduced volumes in both our New York and Pennsylvania service territories.

For several years our efforts to expand these segments have been hampered by industry-wide uncertainties associated with the regulatory restructuring of both the gas and electric industries. While many of these uncertainties continue to exist, in October 2002 we eagerly announced our plans to acquire the Empire State Pipeline from Duke Energy Corporation for $180 million cash plus assumed debt of about $60 million. This pipeline is an important, strategic, close-to-home investment for National Fuel, and we expect it will open new wholesale markets for us and provide substantial expansion opportunities to move gas to locations east of our current service territories.*

We are enthused about acquiring the Empire State Pipeline, but we will not permit that acquisition to impair our balance sheet.* While we await regulatory approvals, we are evaluating a number of scenarios for permanently financing the purchase of this pipeline, which could include the sale of some non-regulated assets, an equity issuance, debt or some combination of these.* We will not let this acquisition derail our commitment to returning to a 50/50 debt-to-equity ratio.*

On the Utility side, we continue to develop and promote natural gas-powered distributed (or "on-site") electric generation. In 2002, we collaborated with our partners in business and government to install new natural gas-powered distributed generation equipment in our service area. In addition to promoting a cleaner environment, this technology will provide a much needed reliable source of power for a nation heavily dependent upon electricity as well as additional throughput for our utility system.*

The Energy Marketing segment achieved a dramatic turnaround as it returned to its local roots and focused on marketing as opposed to trading, something about which we were adamant. This segment was also the fortunate beneficiary of a confluence of favorable events, and next year, we anticipate this segment's earnings will be about one-half of this year's record amount.*

Building on 100 years...

The Exploration and Production segment continues to be an important part of the integrated structure of National Fuel Gas Company. Our long-range plan focuses on managed growth, the reduction of risk and greater emphasis on development drilling. The quest to improve reserves will remain an integral part of these goals.* With our new Canadian management team and the dedicated management and staff in all our North American locations, we are optimistic that implementation of this plan will be successful and will contribute to the stability and reliability of your Company.*

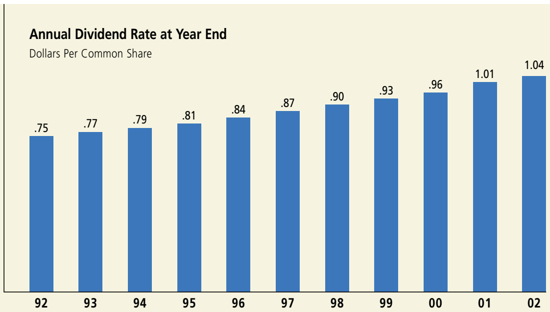
We believe in natural gas and the gas business; natural gas is the best fuel we have available in North America in general, and the United States in particular. Ours is a fundamental service—we provide heat and energy for homes and businesses. Additionally, natural gas is transported through an existing national pipeline system that is an efficient and unobtrusive infrastructure compared to windmills, nuclear power or coal. For these reasons, natural gas is the preferred fuel choice.

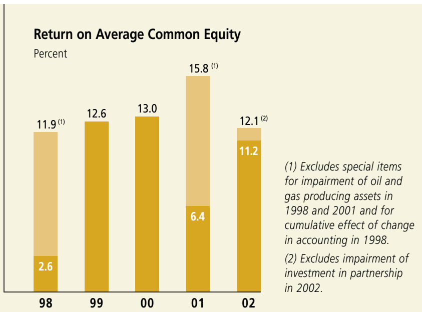
We are committed to being an integrated natural gas company. National Fuel's 100-year milestone serves as a testimonial to the fundamental soundness and enduring nature of our primary product—natural gas. Oftentimes the life cycle of business is subject to the evolution of both technology and consumers' habits; in our case, we continued to thrive. We have been around long enough to have seen the evolution of the various segments of the gas industry and we firmly believe that our Exploration and Production, Pipeline and Storage, and Utility segments tend to naturally counterbalance one another, thereby leading to stability, strength, predictability and continuing growth.*

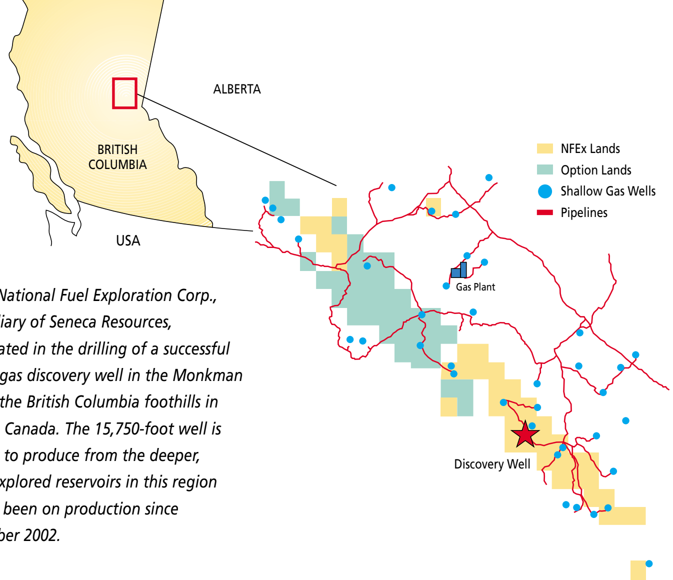
Philip C. Ackerman
Chairman of the Board, President and Chief Executive Officer

As an asset-based, largely regulated, dividend-driven company, we play a role in all facets of the natural gas value chain from the bottom of the well to the burner tip. This means continuous participation in exploration and production, pipeline and storage, utility services and energy marketing. In the following detailed discussion of the performance of your Company, we have modified the presentation of our 2002 operations overview. We begin with the segments which develop resources, specifically Exploration and Production and Timber. Next, the segments which deliver energy, Pipeline and Storage and International, are reviewed. Lastly, the segments which serve customers, the Utility and Energy Marketing, are presented. We believe this format presents a more cohesive view of our integration and further illustrates the value our segments bring to your diversified energy Company.

All references to earnings per share are to diluted earnings per share.

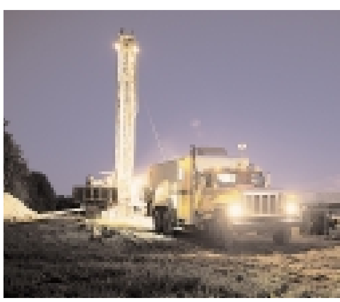


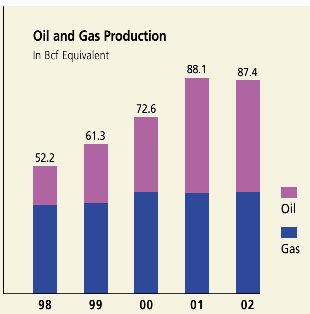


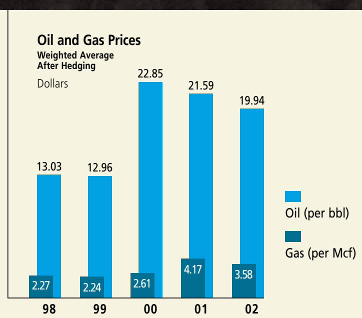


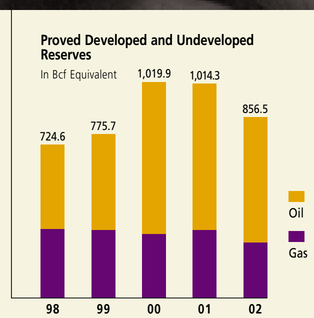
In July, National Fuel Exploration Corp., a subsidiary of Seneca Resources, participated in the drilling of a successful natural gas discovery well in the Monkman area of the British Columbia foothills in western Canada. The 15,750-foot well is the first to produce from the deeper, under-explored reservoirs in this region and has been on production since September 2002.

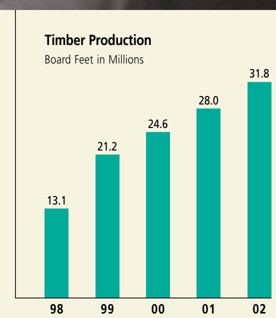
The Exploration and Production segment drilled a shallow exploratory well in a shale formation near Collins Center, N.Y. Here, Senior Geologist Cary Kuminecz (left) discusses the data being collected with a technician during well logging, a process that, among other things, provides critical information about the shale fractures where natural gas may collect. In the background, as seen through the windows of the logging truck, a variety of electrical tools lowered into the well collect the data for analysis.











...developing resources...

This year, the **Exploration and Production** segment earned $26.9 million or $0.33 per share compared with $71.8 million or $0.89 per share last year (excluding last year's impairment of oil and gas assets). Earnings thus decreased $44.9 million or $0.56 per share from last year, primarily as a result of significantly lower commodity prices. Oil and gas production in 2002 of 87.4 billion cubic feet equivalent (Bcfe) was nearly flat when compared to last year's production of 88.1 Bcfe. Earnings in 2001 included a non-cash impairment of the oil and gas assets totaling $104.0 million or $1.29 per share. Including this impairment, 2002 earnings increased $59.2 million compared with a loss in 2001 of $32.3 million or $0.40 per share.

At September 30, 2002 this segment's crude oil and natural gas reserves were 856.5 Bcfe, a decline of 157.8 Bcfe or 15.6% from last year's reserve total of 1,014.3 Bcfe. This was the result of several factors: total production of 87.4 Bcfe; sales of properties of 18.4 Bcfe; and reserve replacements of 48.9 Bcfe which were not enough to offset a 100.9 Bcfe reserve reduction attributable to uneconomic development drilling properties in a portion of our Canadian and California divisions. We simply did not find what we expected from our Canadian purchases. However, we were able to replace our entire 2002 Canadian production of 23.4 Bcfe. While the reduction in reserves was disappointing, it should not overshadow the overall performance of this segment.

The Timber segment invested in an optimizing edger at its Marienville, Pa. mill. This machine scans the board surface and sets the edger saws to maximize the useable volume and value of each board. From inside a booth, employee Todd Swanson analyzes the image on his computer screen and the laser lines cast on the board to ensure optimal positioning before the saws make the final cuts.

Our reserve-to-production ratio is currently about 10 years.* Because our capital spending is structured to live within our cash flows, planned 2003 capital expenditures for this segment are currently $81.6 million, with nearly one-half of that targeted for our Canadian operations.* This spending includes plans to drill approximately 212 new wells throughout the United States and Canada, with an emphasis on natural gas production.* As a result of these programs, we expect an increase in our reserve-to-production ratio.* We have new management within our Canadian division and, with their direction, we've begun a successful shallow well drilling program for natural gas in southwest Saskatchewan where we have acquired over 24,000 acres. Like our Appalachian Basin properties, this region also has long-lived gas reserves and low-cost drilling. Results, thus far, have been very encouraging.*

An arrangement with Talisman Energy Inc., a Calgary-based Canadian drilling company, provided us with an opportunity to participate as a 20% partner in drilling operations in the Monkman region of western Canada where, in late July 2002, we announced the successful completion of the Sukunka well. While this first well opens the possibility of very substantial reserves for the area, the full evaluation of this potential will require many additional wells.* The drilling of a second well has begun.*

Our extensive lease holdings throughout North America provide significant potential for developing and adding to our reserves. In the Appalachian region alone we hold nearly 900,000 acres either in leasehold or fee interest. Likewise, we have more than 750,000 acres in Canada where we already have 214.3 Bcfe of reserves, or approximately 25% of our total reserve base.

In 2002 we continued changing our emphasis from being an offshore exploration company to an onshore North American production company.* We anticipate this transition will continue over another five years or so.* Our Gulf of Mexico wells, with current gross production of nearly 85 million cubic feet per day (MMcf/d) of natural gas and 5,500 barrels of oil per day, will yield diminished contributions in the future.* As we drill longer-lived wells onshore, it will be difficult for our onshore production to make up the difference in the short term, presenting a challenge to maintain production.* Consequently, planned production for 2003 is expected to be in the range of 80 to 85 Bcfe.* In the longer term, however, we expect the combined production from our long-lived reserves to grow each year.* Our main objectives are to increase reserves and production while controlling expenditures and, ultimately, reducing the risk associated with exploration and production of natural gas and oil.*

Developing natural resources is not limited to our exploration and production operations. Our **Timber** segment also creates value by managing its resources. In 2002, reported earnings for this segment of $9.7 million or $0.12 per share was an increase of $2.0 million or $0.03 per share compared to last year's earnings. This resulted from a nearly 14% increase in the number of board feet harvested. In addition, in June 2002, the Company purchased over 3,600 acres of land and timber in Potter County, Pennsylvania. The timber business has been good for us and we expect to be an active player in both buying and selling as the situations warrant.*

One of the ways we strive to increase profits in this segment is by using efficient production equipment such as the optimizing edger. This equipment employs laser and computer technology to mitigate waste and extract maximum value from each board as it passes through our sawmill. Through ongoing, careful forestry management, this naturally replenishing resource will be available for future generations, providing both a long production profile and a continuing contribution to earnings.*

Horizon Power owns a 50% interest in this 5.6 megawatt power plant located near Lewiston, N.Y. Methane gas produced from an adjacent landfill is gathered and treated before it is routed to fuel the seven engines which generate electricity to feed the power grid serving western New York.

Our **Pipeline and Storage** segment is the link between the wellhead and the burner tip, providing utilities and marketers with natural gas transportation and storage services. Earnings in this segment in 2002, exclusive of the write down of the Independence Pipeline project discussed below, were $39.6 million or $0.49 per share. This is essentially equivalent to last year's earnings of $40.4 million or $0.50 per share.

We continue to evaluate opportunities relating to the transportation and storage of natural gas.* We firmly believe that as our nation's energy needs continue to grow, so too must our natural gas pipeline infrastructure.* However, due to a lack of industry willingness to commit to sufficient volumes, the Independence Pipeline project was abandoned. We had a one-third partnership interest in that project, and we recorded an after-tax non-recurring charge to earnings of $9.9 million or $0.12 per share. This large-diameter pipeline project would have moved gas from Defiance, Ohio to the Leidy, Pennsylvania hub.

...delivering energy...

We are continuing to pursue the proposed Northwinds Pipeline project with our partner TransCanada PipeLines Limited. This proposed pipeline represents a balanced and manageable opportunity to secure market support and would add another critical link to our existing transmission system, enabling gas to move from western Canada and the Canadian storage fields near Dawn, Ontario to the East Coast markets in the United States.* The design and all preliminary environmental work are complete and an active marketing program is underway. Costs associated with this project are currently expensed as incurred, and therefore are not included in this year's capital expenditures, nor on our balance sheet. This project's total cost is estimated to be about $375 million.*

National Fuel Gas Supply Corporation's second horizontal well, at Lawtons Storage Field, has a vertical depth of 2,400 feet and a lateral length of 1,500 feet in the Whirlpool sandstone formation. This well is designed to improve the withdrawal capabilities of this field near Collins Center, N.Y.

Both the Independence and Northwinds projects bring to light the critical need for government agencies and the public to understand the necessity of additional natural gas pipeline infrastructure. Pipeline projects have been delayed because of uncertainties associated with unbundling traditional utility services. Also the national gas delivery system has inherently become more efficient through deregulation and competition. These factors, plus warmer-than-normal winters and a slower economy, have created the illusion that the existing energy infrastructure is sufficient to meet our needs. The reality is that the underlying need for new pipeline capacity is still there and has grown. Projects like the Northwinds Pipeline would improve the infrastructure and will be needed to meet the energy needs of future generations.*

The Empire State Pipeline will be an important and strategic addition to our system and will provide us with long-term growth opportunities to serve markets previously beyond our reach.* We recently announced our intent to acquire this 157-mile, 24-inch pipeline which begins at the Canadian border near Buffalo, New York and terminates just north of Syracuse, New York. A substantial portion of its 525 MMcf/d capacity is under long-term contracts with major industrial companies, utilities (including the Company's Utility segment) and power producers. Because the pipeline is not currently equipped with compressors, future installation of that equipment could substantially increase the capacity of the line.* Expansion of the pipeline can include connecting to several proximate storage fields, other interstate pipelines and local utilities to better serve customers.* Upon receipt of the appropriate regulatory approvals, which we expect will occur early in calendar 2003, we will complete this key acquisition.*

Opportunities for system expansion are intricately associated with the need for storage facilities.* Our first horizontal storage well, drilled in our Holland Storage Field, was very successful. The significant improvement in the injection and withdrawal rates allows for more rapid delivery of natural gas in both the heating and cooling months. This past summer we drilled a second horizontal well at our Lawtons Storage Field in southern Erie County, New York. Together with the incremental expansions made at major compressor stations, our customers' needs are well served by our ability to provide additional capacity to deliver natural gas efficiently to them.

The need for building energy infrastructure is not limited to the United States. Since 1995 our **International** segment's investment in Central Europe, specifically the Czech Republic, has been focused on providing additional electric power generation using a source cleaner than the old, existing coal-fired plants. Conversion of the 1960's vintage "stoker" boilers to clean-burning fluidized bed combustion has been a major step in rebuilding that infrastructure. However, the process to do so has been disappointingly slow to materialize. In 2002, the International segment experienced a loss of $4.4 million or $0.06 per share compared with a loss of $3.0 million or $0.04 per share last year. Higher operation and maintenance expenses associated with the Company's European power development projects were the primary factors for the higher loss this year. The impact of warmer-than-normal weather this year was partially offset by the appreciation in the value of the Czech koruna compared to the U.S. dollar.

In 2002, capital expenditures of $4.2 million were modest and primarily included construction on boilers and additional improvements at the district heating and power generation plants in the Czech Republic. Estimated capital expenditures for 2003 of approximately $9.6 million will concentrate on improvements and replacements at the same facilities.*

The Company signed a joint development agreement as a 50% owner with an Italian utility for the construction of a state-of-the-art 400-megawatt combined-cycle natural gas-fired electric generating plant. The estimated cost of this project is about $200 million.* Additionally, the opportunity to construct, own and operate two new 127-megawatt gas-fired combustion turbines is being pursued in Bulgaria and the estimated cost of this project is also about $200 million.* Costs associated with the Company's power development projects in Italy and Bulgaria are not capitalized and are not included in the capital expenditures nor on the balance sheet. Both of these projects will be pursued only with significant capital commitments from third parties.*

Our knowledge of natural gas production and transmission has been applied successfully to yet another means of delivering energy. In partnership with various entities, we have interests in two domestic electric generating plants that are fueled by methane gas derived from landfill sites, with the electricity being sold directly to the power grid. An estimated one-third of all landfills in the United States are suitable for methane collection. Consequently, we continue to work with municipalities and landfill companies to apply this technology and seek more opportunities to develop landfill gas projects. While these relatively low-cost investments presently earn modest profits, they provide a unique benefit to the environment by "recycling" the methane gas that was previously released into the atmosphere.

Utility crews excavated a 500-foot section of 4-inch medium pressure plastic line that crossed a 150-foot creek bed in Belmont, N.Y. after water erosion exposed the pipeline. The water was diverted around a dam during construction. One track machine broke the bedrock on the creek bottom while the other machine excavated. A 6-inch casing was set in concrete in a 3-foot trench and later, a 4-inch plastic carrier pipe was inserted into the casing.

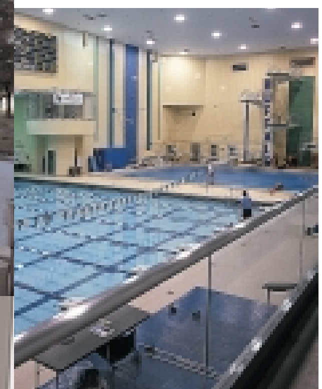
...serving customers...

The **Utility** segment's 2002 earnings of $49.5 million or $0.62 per share reflect a decrease of $11.2 million or $0.14 per share from last year's earnings. This was primarily the result of a warmer-than-normal winter driving down volumes in the Pennsylvania division. In New York, the effect of weather variations on revenue is moderated by a weather normalization clause. The earnings impact was further limited by our continuing cost control efforts, which are ongoing and remain a primary focus of management.*

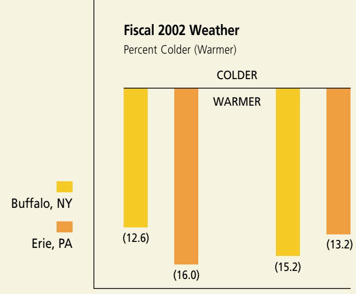
In 2002, capital expenditures of $51.5 million were made for replacement of mains, main extensions and service lines. For 2003, capital spending of $48.1 million will likewise be concentrated on main and service line improvements.* Over the past 10 years, the Company has spent $566 million on upgrading its distribution pipeline system. We have been very focused on assuring that these expenditures were prudent and in furtherance of our mission to provide safe and reliable service by achieving significant improvements in the basic performance of our system. We converted a substantial portion of the distribution system from low to medium pressure, and replaced over 2,500 miles of bare steel and cast iron mains and services in our system with plastic pipe. The number of leaks reported annually was reduced by nearly 50% during that same

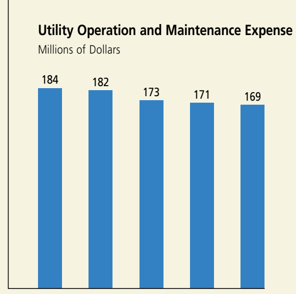
Daisy Rosario is one of 31 customer service representatives at the Utility's Erie, Pa. combined customer assistance center (CAC) and consumer response center (CRC). National Fuel has nine CACs and two CRCs throughout its service area in western New York and northwestern Pennsylvania.

At the CACs, customers can pay their gas bills, request new services or discuss billing or special programs with our experienced staff. In 2002, our employees processed more than 500,000 customer transactions and answered more than 1.5 million calls.



The Alumni Arena at the State University of New York at Buffalo is a premier NCAA Division I sports facility that includes a 600,000-gallon competition pool and a 400,000-gallon diving pool. The Utility partnered with Gerster Trane Energy Services and the New York State Energy Research and Development Authority (NYSERDA) to use distributed generation as part of an energy efficiency plan. Two 60-kilowatt natural gas-fueled microturbine generators produce electricity which powers the pools' circulating pumps. A heat recovery system, which uses waste heat from the microturbines' operations, warms the pool water. The double benefits of generating electricity while recovering waste heat results in exceptional energy efficiencies and low-cost operation.





10-year period. These maintenance programs are performed to ensure the integrity of a pipeline distribution system that serves our more than 730,000 customers throughout New York and Pennsylvania.

For nearly two decades, commercial and industrial customers have been able to choose their natural gas supplier. Choice of supplier for residential customers has been available only since 1996 and it remains an issue of intense regulator interest. In New York and Pennsylvania, regulators have wisely adopted a conservative, evolutionary approach to the restructuring effort with a focus on preserving reliability and the financial integrity of utilities responsible for maintaining the distribution infrastructure. Despite their aggressive efforts to attract marketers with subsidized bill credits and other incentives, customer enrollment levels are either flat or falling in both states. In an effort to reverse the trend in New York, the Utility, in conjunction with the New York State Public Service Commission (PSC), launched an integrated communication program in its service territory to promote customer choice. While overall awareness improved 35%, it remains to be seen whether this increased awareness results in higher marketer enrollment levels.

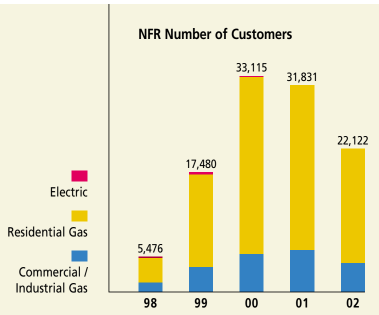
In the wake of Enron's collapse, national marketers have largely abandoned small-volume retail programs. This may be good news for local or regional marketers who now dominate the retail markets; however, the model of robust retail competition envisioned by regulators and lawmakers remains unrealized. For now, most customers are content to stay with their utility rather than choosing a marketer. In any event, the Utility remains dedicated to customer choice initiatives and we recognize the importance of being among the choices of natural gas suppliers.

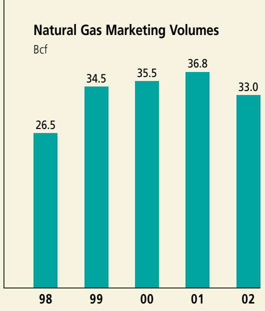
Excellence in customer service remains among the Utility's greatest strengths. In New York, our residential customer satisfaction levels, which are continually monitored by the PSC, have risen each year over the last five years from 85.9% to 91.3%. In January 2002, we began monitoring customer satisfaction levels in our Pennsylvania service territory. In a new Pennsylvania statewide survey, which measured customer service satisfaction among customers who had recently contacted their utility, our Utility ranked first among Pennsylvania's seven major public gas utilities during the first six months of calendar 2002. We are very proud of our record regarding customer satisfaction and we remain committed to our long tradition of exemplary service.*

Technology plays an integral part in our efforts to deliver excellent customer service. Distributed generation offers security, reliability, efficiency and environmental benefits. By using distributed generation, commercial and industrial customers can produce their own power on site and reduce their susceptibility to the financial impact resulting from power losses related to natural disasters or sabotage to a power plant supplying the grid.* For over 15 years, the Utility has actively pursued the development of distributed generation technologies for residential, commercial and industrial customers and has

The Utility supported the development of distributed generation technologies by partnering with ATSI Engineering Services, Plug Power Inc. and NYSERDA to install two residential fuel cell systems in its western New York service area. Since April 2002, the fuel cell pictured here has produced electricity for the adjacent home in Lewiston, N.Y. through an electrochemical process that uses natural gas delivered through the Utility's system.

The Energy Marketing segment was profitable in 2002 due to the implementation of improved operational strategies. Here (clockwise from lower left) Daniel Burkhardt, Cindy Wilkinson, Michael Bielawski, Donna DeCarolis, Jack Palkowski and Gwen Appelbaum discuss objectives for the coming year at National Fuel Resources' office in Williamsville, N.Y.





successfully installed this equipment at hospitals, nursing homes, public schools, car washes and food processing plants. Through research and development programs and cost-saving strategies, the Utility has helped its customers and gained valuable experience with many types of distributed generation technologies, including natural gas engines, microturbines and fuel cells. The potential for growth of distributed generation is significant, especially given the complicated reliability and security issues presently confronting our industry and our nation.*

The Utility remains a key part of the National Fuel system and continues to deliver the same steady, reliable performance long expected by our shareholders and customers. This is made possible through the efforts of an outstanding workforce that consistently meets and exceeds the challenges of safely delivering gas service to the hundreds of thousands of customers who expect nothing less. These qualities are important to our shareholders, to our customers and to the regions we serve.

The natural complement to the Utility is our **Energy Marketing** segment, which provides retail natural gas services to industrial, commercial, public authority and residential customers. In 2002, earnings in this segment were $8.6 million or $0.11 per share compared to a loss of $3.4 million or $0.04 per share last year. The turnaround was primarily related to improved operational strategies employed by this segment's new management team. Through a refocus on our core market, new pricing arrangements with greater margin predictability, cost-effective asset management and improved risk management, this segment returned to profitability. These steps, combined with lower bad debt, interest and other operating expenses, contributed to the improved financial results. We are proud of the remarkable turnaround in this segment and we believe we have the team in place for it to remain a positive contributor to future corporate performance.*

In addition to the very successful changes of management in Energy Marketing, there are other changes which are bittersweet. Two distinguished members of your Board of Directors, William J. Hill and Eugene T. Mann, will be retiring at the upcoming Annual Meeting. We thank them for their many years of service to our Company and wish them years of happiness. As a result of the pending vacancies, Rolland E. Kidder was elected to the Board of Directors in September 2002. Mr. Kidder brings extensive experience in the oil and gas business to our Board, and his tenure with the New York Power Authority provides additional value to your Company. We have also nominated R. Don Cash to serve on your Board. Mr. Cash, currently Chairman of Questar Corporation, has nearly 40 years of experience, many of them with an integrated natural gas company. Lastly, after more than 24 years of service, Gerald T. Wehrlin, Controller of National Fuel Gas Company and President of National Fuel Resources, Inc., announced his retirement effective February 1, 2003.

...for the next century.

Profound changes have taken place in our country, in corporate America and in the energy industry in the last 16 months, and while I remain disappointed by the behavior of certain individuals, my faith in the people and strategies of National Fuel has been reaffirmed. For 100 years this Company has been built slowly but surely by people who believed that success could be achieved by owning hard assets and providing real services in a straightforward, uncomplicated manner. It turns out they were right.

On the following pages, I hope you will look with pride, as I have, on the history of our industry and in particular the growth and accomplishments of your Company. Ultimately, it was the pride and dedication of the thousands of men and women who worked, and continue to work, for your Company that make our story possible.

Philip C. Ackerman, *Chairman of the Board, President and Chief Executive Officer*
December 12, 2002

Note:
This document contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements, including those designated by an asterisk ("*"), should be read with the cautionary statements and important factors included at Item 7 of the Company's Form 10-K, under the heading "Safe Harbor for Forward-Looking Statements."

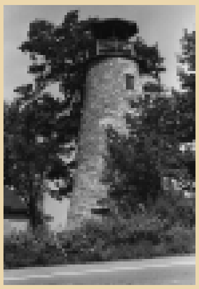
The History of the
Natural Gas Industry and National Fuel

1821 ▶

By a process similar to this, William Hart drills the world's first commercial natural gas well in Fredonia, N.Y., to a depth of 27 feet. A boulder commemorating this event was placed along Route 20 in Fredonia and exists today.

1902

National Fuel Gas Company incorporates on December 8; acquires interests in Pennsylvania Gas Company, United Natural Gas Company and others, which were the principal assets of Standard Oil's Natural Gas Trust of 1886.



◀ 1830

Located in Barcelona Harbor on Lake Erie is the world's first lighthouse lighted with natural gas, which comes from a nearby well. The lighthouse operates until 1959 when the harbor is no longer active.

1854

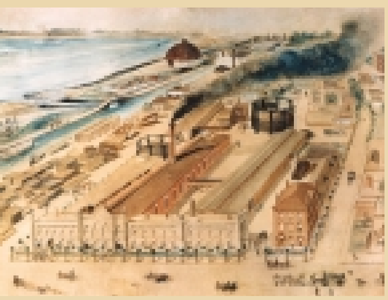
First deep natural gas well is drilled in Erie, Pa.

1903

First stockholder dividend is declared. Dividends would be uninterrupted for the next 100 years.

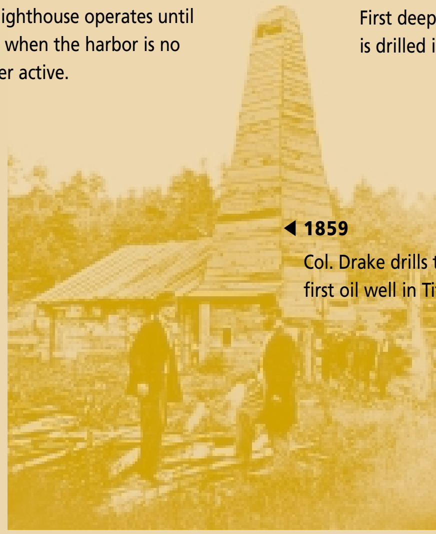
1911 ▶

Iroquois Natural Gas Company (renamed Iroquois Gas Corporation in 1921) is formed by National Fuel. From 1913 to 1958, its offices are located in "The Iroquois Building" in downtown Buffalo, N.Y.



1848 ▲

Buffalo Gas Light Company builds Jackson Street Gasworks.



◀ 1859

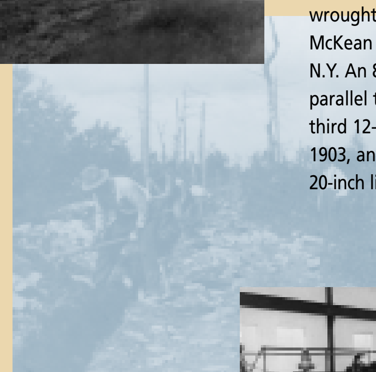
Col. Drake drills the world's first oil well in Titusville, Pa.

1870

The world's first iron natural gas line is constructed from Newton, Pa., to Titusville.

◀ 1886

United Natural Gas Company constructs an 87-mile, 8-inch wrought iron pipeline from McKean County, Pa., to Buffalo, N.Y. An 8-inch line is installed parallel to it around 1895, a third 12-inch line is added in 1903, and in 1912, a fourth 20-inch line is laid (pictured here).



◀ 1872

The world's first long-distance wooden natural gas pipeline is built, extending 25 miles from West Bloomfield, N.Y., to Rochester, N.Y., and uses 20 acres worth of hollowed-out Canadian white pine logs.

1885

United Natural Gas Company is organized.

1885 ▼

The famous Speechley well furnishes Oil City, Titusville and Franklin, Pa., with their entire gas supply.

1880

The world's first natural gas compressor station is built at Rixford, Pa.

1881

Warren Light and Heat Company is incorporated (renamed Pennsylvania Gas Company in 1885).

1899 ▶

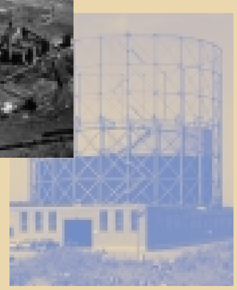
United Natural Gas Company installs its first 1,000 horsepower gas compressor in Mount Jewett, Pa., which is used until the 1950s.

1913

Mars Natural Gas Company forms; it is acquired by National Fuel in 1918 and renamed Seneca Resources Corporation in 1976.

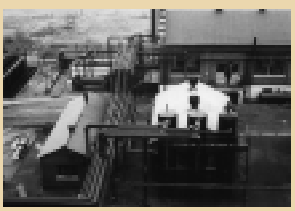
1916

First successful underground natural gas storage field in the United States is established at Zoar Field, south of Buffalo, N.Y.



1923

Mineral Spring Works in West Seneca, N.Y., is constructed by Iroquois Gas Corporation to generate additional manufactured gas from coal, but later houses gas compressors and operations personnel. This facility is still in use today.



1925

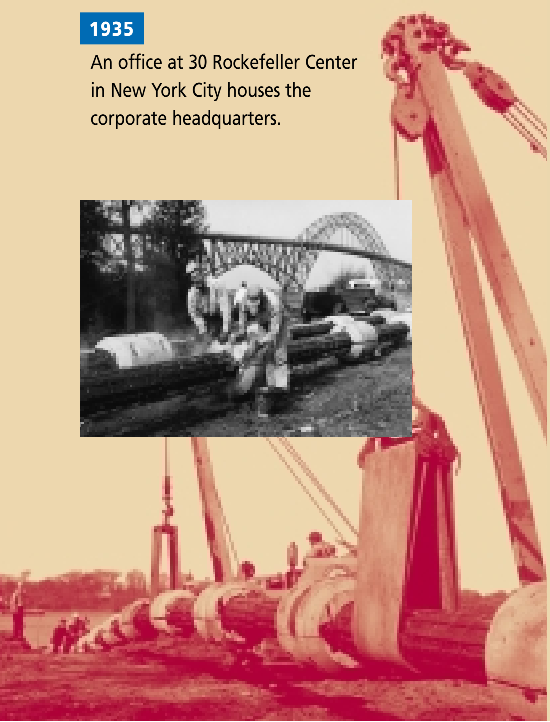
Erie Works in Erie, Pa., is built by Pennsylvania Gas Company to process manufactured gas.

1935

Congress passes the Public Utility Holding Company Act. National Fuel is one of five gas-only utilities still regulated by it.

1935

An office at 30 Rockefeller Center in New York City houses the corporate headquarters.



1938

Congress passes the Natural Gas Act.

1939

Company assets reach $100 million.

1943

The Rockefeller Foundation, which possessed about 20% of the shares of National Fuel, elects to sell all of its shares. As a result, a public offering in April 1943 of 412,042 shares of capital stock increases the number of shareholders to 10,161.

1950s & 1960s

The natural gas boom of the 1950s and '60s brings natural gas to many communities for the first time. This 12-inch line project crossing from Buffalo to Grand Island, N.Y. involves dredging the river and the burying of the pipe under the riverbed by saddling it with 1,000-pound weights called "River Dogs."

1953

National Fuel becomes a true regional natural gas utility with the acquisition of Republic Light, Heat and Power Company. Its service area expands to include Batavia, Dunkirk, Niagara Falls, Silver Creek, South Shore, Westfield, Brocton, Tonawanda, North Tonawanda and Kenmore, and villages in Chautauqua, Erie, Genesee and Ontario Counties in New York.

1954

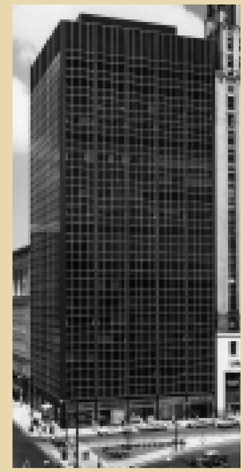
U.S. Supreme Court decision in Phillips Petroleum case confirms federal control of natural gas prices.

1955

Common stock of National Fuel is listed on the New York Stock Exchange.

1959

National Fuel moves its Buffalo offices to the new 10 Lafayette Square building, the city's first new skyscraper in 30 years.



1959

National Fuel is honored by the New York Stock Exchange and initiated into a select circle of corporations that paid regular quarterly dividends for 50 years or more.

1971

National Fuel increases its dividend to shareholders. Yearly dividend increases continue through the present day.

1973

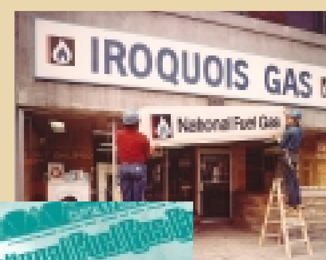
OPEC Oil Embargo begins; gas curtailments of industrial customers.

1974

Synthetic natural gas from the Ashland Oil plant in Tonawanda, N.Y., adds 7% to fuel supply.

1974

National Fuel realigns United Natural Gas Company, Pennsylvania Gas Company and Iroquois Gas Corporation into National Fuel Gas Distribution Corporation, the regional utility, and National Fuel Gas Supply Corporation, the pipeline, storage and transmission business.



1976

Seneca Resources Corporation opens Houston office.

1976

National Gas Storage Corporation (later renamed Penn-York Energy Corporation) is formed.

1977

Employees battle extremely cold temperatures, high winds and huge snowdrifts during the "Blizzard of '77." In addition, there are labor strikes and gas shortages in this year. Through it all, National Fuel's customers have service due to the efforts of employees.

1978

Congress passes the Natural Gas Policy Act.

1978

National Fuel opens its Pennsylvania headquarters at 800 State Street in Erie, Pa.

1982

EnerOp Corporation (later renamed Leidy Hub, Inc.) forms to market compressed natural gas equipment for vehicles.

1982

National Fuel creates a Dividend Reinvestment Plan to make it easy for shareholders to reinvest their National Fuel dividends in buying more National Fuel stock.

1982

Boundary Gas Project imports gas from Canada.

1983

National Fuel Gas Distribution Corporation begins transporting gas for industrial customers.

1983

National Fuel Gas Supply Corporation building is constructed at 1100 State Street, Erie, Pa.

1983

Empire Exploration, Inc. forms to explore and develop Appalachian oil and gas rights.

1983

Highland Land and Minerals, Inc. (later renamed Highland Forest Resources, Inc.) forms to engage in timber and sawmill businesses.

1984

National Fuel stock splits and a 10% stock dividend also is declared.

1987

National Fuel declares another 2-for-1 stock split, as the stock reaches what was then an all time high price of $24.

1987

Seneca Resources secures a 75% interest in Argo Petroleum Corporation's principal oil and gas properties, adding proved reserves of over 9 million barrels of oil and 19.1 Bcf of gas.

1987

National Fuel purchases Utility Constructors, Inc., a pipeline construction company in Linesville, Pa.

1988

Net plant reaches $1 billion.

1988

Distribution Corporation constructs its first public natural gas vehicle fueling station at Tonawanda Service Center.

1989

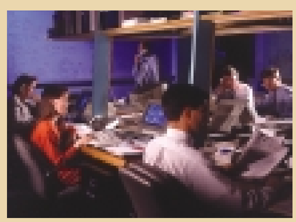
First phase of Canadian Gas Pipeline is approved by FERC.

1990

Supply Corporation receives FERC approval to become an open-access transporter of natural gas.

1991

National Fuel Resources, Inc. forms to market natural gas.



1991

National Fuel offers a "Customer Stock Purchase Plan" to give customers the opportunity to buy National Fuel stock without paying commissions.

1993

Supply Corporation unbundles its services under FERC Order 636 and exits the gas sales business; Distribution Corporation begins purchasing all of its gas from third parties.

1994

Seneca Resources drills its first offshore well in the Gulf of Mexico at West Cameron 230.

1994

Empire Exploration merges into Seneca Resources; Penn-York merges into Supply Corporation.

1995

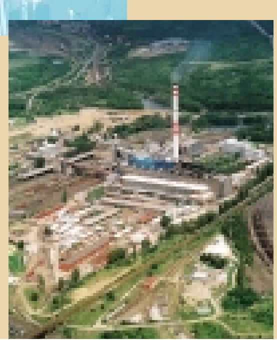
NFR Power, Inc. (later renamed Horizon Power, Inc.) forms to engage in the electric business.

1995

National Fuel moves its corporate headquarters to Buffalo, closing the New York City office due to its decreasing role in operations and as part of an ongoing search for cost efficiencies.

1995

Horizon Energy Development, Inc. forms to engage in development, financing and acquisition of foreign utility companies. In 1998, Horizon acquires a power and district heating company in the Czech Republic, pictured here.



1998

Seneca Resources acquires three properties in California, which contribute approximately 436 Bcfe to total reserve base.

2000

Seneca Resources acquires Tri-Link Resources in Canada.

2001

Talisman Energy and Seneca Resources announce joint exploration project in Appalachian region.

2001

Seneca Resources forms National Fuel Exploration Corp., headquartered in Calgary, Alberta, and acquires Player Petroleum Corporation in Canada.

2001

National Fuel declares its third 2-for-1 stock split in 20 years and increases the dividend 5.2% to $2.02 per share.

2002

National Fuel announces plans to acquire Empire State Pipeline, a 24-inch, 157-mile natural gas pipeline that extends from Buffalo to near Syracuse, N.Y.

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

Form 10-K

Annual Report Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934
For the Fiscal Year Ended September 30, 2002

Commission File Number 1-3880

National Fuel Gas Company

(Exact name of registrant as specified in its charter)

New Jersey (State or other jurisdiction of incorporation or organization)	**13-1086010** (I.R.S. Employer Identification No.)
10 Lafayette Square **Buffalo, New York** (Address of principal executive offices)	**14203** (Zip Code)

(716) 857-7000
Registrant's telephone number, including area code

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

Title of each class	Name of each exchange on which registered
Common Stock, $1 Par Value, and Common Stock Purchase Rights	New York Stock Exchange

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

None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. YES ✔ NO __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $1,634,293,000 as of November 30, 2002.

Common Stock, $1 Par Value, outstanding as of November 30, 2002: 80,437,839 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for the Annual Meeting of Shareholders to be held February 20, 2003 are incorporated by reference into Part III of this report.

Form 10-K Contents

Part I

This Form 10-K contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements included in this Form 10-K at Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), under the heading "Safe Harbor for Forward-Looking Statements." Forward-looking statements are all statements other than statements of historical fact, including, without limitation, those statements that are designated with an asterisk ("*") following the statement, as well as those statements that are identified by the use of the words "anticipates," "estimates," "expects," "intends," "plans," "predicts," "projects," and similar expressions.

Part II

Part III

Part IV

Part I

ITEM 1 BUSINESS

The Company and its Subsidiaries

National Fuel Gas Company (the Registrant), a holding company registered under the Public Utility Holding Company Act of 1935, as amended (the Holding Company Act), was organized under the laws of the State of New Jersey in 1902. The Registrant is engaged in the business of owning and holding securities issued by its twelve directly owned subsidiary companies. Except as otherwise indicated below, the Registrant owns all of the outstanding securities of its subsidiaries. Reference to "the Company" in this report means the Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure. Also, all references to a certain year in this report relate to the Company's fiscal year ended September 30 of that year unless otherwise noted.

The Company is a diversified energy company consisting of six reportable business segments.

1. The Utility segment operations are carried out by National Fuel Gas Distribution Corporation (Distribution Corporation), a New York corporation. Distribution Corporation sells natural gas or provides natural gas transportation services to approximately 732,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by Distribution Corporation include Buffalo, Niagara Falls and Jamestown, New York and Erie and Sharon, Pennsylvania.

2. The Pipeline and Storage segment operations are carried out by National Fuel Gas Supply Corporation (Supply Corporation), a Pennsylvania corporation. Supply Corporation provides interstate natural gas transportation and storage services for affiliated and nonaffiliated companies through (i) an integrated gas pipeline system extending from southwestern Pennsylvania to the New York-Canadian border at the Niagara River and (ii) 28 underground natural gas storage fields owned and operated by Supply Corporation as well as four other underground natural gas storage fields operated jointly with various other interstate gas pipeline companies. Seneca Independence Pipeline Company (SIP) held a one-third general partnership interest in Independence Pipeline Company (Independence), a Delaware general partnership that had proposed to construct and operate a 400-mile pipeline to transport natural gas from Defiance, Ohio to Leidy, Pennsylvania (the Independence Pipeline). Independence was dissolved on September 30, 2002. As discussed in Item 7, MD&A under the heading "Capital Resources and Liquidity", in June 2002 Independence submitted a motion to the Federal Energy Regulatory Commission (FERC) requesting that FERC vacate the certificate that it had issued to Independence to construct, own and operate the Independence Pipeline. FERC formally vacated the certificate in July 2002.

As discussed below under "Competition: The Pipeline and Storage Segment", in October 2002 the Company announced its intention to buy the Empire State Pipeline (Empire) from Duke Energy Corporation.

3. The Exploration and Production segment operations are carried out by Seneca Resources Corporation (Seneca), a Pennsylvania corporation. Seneca is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, in Wyoming and in the Gulf Coast region of Texas and Louisiana. Also, Exploration and Production operations are conducted in the provinces of Manitoba, Alberta, Saskatchewan and British Columbia in Canada by Seneca's wholly-owned subsidiaries, National Fuel Exploration Corp. (NFE), an Alberta, Canada corporation, and Player Resources Ltd. (Player), an Alberta, Canada corporation.

4. The International segment operations are carried out by Horizon Energy Development, Inc. (Horizon), a New York corporation. Horizon engages in foreign and domestic energy projects through investments as a sole or substantial owner in various business entities. These entities include Horizon Energy Holdings, Inc., a New York corporation, which owns 100% of Horizon Energy Development B.V. (Horizon B.V.). Horizon B.V. is a Dutch company whose principal asset is majority ownership of United Energy, a.s. (UE), a wholesale power and district heating company located in the northern part of the Czech Republic.

5. The Energy Marketing segment operations are carried out by National Fuel Resources, Inc. (NFR), a New York corporation which markets natural gas to industrial, commercial, public authority and residential end-users in western and central New York and northwestern Pennsylvania, offering competitively priced energy and energy management services for its customers.

6. The Timber segment operations are carried out by Highland Forest Resources, Inc. (Highland), a Pennsylvania corporation, and by a division of Seneca known as its Northeast Division. This segment markets timber from its New York and Pennsylvania land holdings, owns three sawmill operations in northwestern Pennsylvania and processes timber consisting primarily of high quality hardwoods.

Financial information about each of the Company's business segments can be found in Item 7, MD&A and also in Item 8 at Note I - Business Segment Information.

The Company's other wholly-owned subsidiaries are not included in any of the six reportable business segments and consist of the following:

• Upstate Energy Inc. (Upstate), a New York corporation engaged in wholesale natural gas marketing and other energy-related activities;

• Niagara Independence Marketing Company (NIM), a Delaware corporation which owns a one-third general partnership interest in DirectLink Gas Marketing Company (DirectLink), a Delaware general partnership. DirectLink, was formed to engage in natural gas marketing and related businesses in part by subscribing for firm transportation capacity on the proposed Independence Pipeline (see Pipeline and Storage segment discussion above);

• Leidy Hub, Inc. (Leidy), a New York corporation formed to provide various natural gas hub services to customers in the eastern United States;

• Data-Track Account Services, Inc. (Data-Track), a New York corporation which provides collection services principally for the Company's subsidiaries; and

• Horizon Power, Inc. (Horizon Power), a New York corporation which is designated as an "exempt wholesale generator" under the Holding Company Act and is developing or operating mid-range independent power production facilities.

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2002.

Rates and Regulation

The Company is subject to regulation by the Securities and Exchange Commission (SEC) under the broad regulatory provisions of the Holding Company Act, including provisions relating to issuance of securities, sales and acquisitions of securities and utility assets, intracompany transactions and limitations on diversification. In 2002, both houses of Congress passed comprehensive energy bills that included repeal of the Holding Company Act. The bills were referred to a conference committee of the House and Senate, but no action was taken by the conferees prior to adjournment. It is likely that comprehensive energy legislation, including repeal of the Holding Company Act, will be re-introduced in the next session of Congress.* Thus far, the proposed legislation would transfer certain oversight responsibilities to the various state public utility regulatory commissions and FERC and would expand the access of these bodies to the books and records of companies in a holding company system. The proposed legislation could increase regulation, especially at the state level.* By contrast, previous SEC rule changes have reduced the number of applications required to be filed under the Holding Company Act, exempted some routine financings and expanded diversification opportunities. The Company is unable to predict at this time what the ultimate outcome of legislative or regulatory changes will be and, therefore, what impact such efforts might have on the Company.*

The Utility segment's rates, services and other matters are regulated by the State of New York Public Service Commission (NYPSC) with respect to services provided within New York and by the Pennsylvania Public Utility Commission (PaPUC) with respect to services provided within Pennsylvania. For additional discussion of the Utility segment's rates and regulation, see Item 7, MD&A under the heading "Rate Matters" and Item 8 at Note B-Regulatory Matters.

The Pipeline and Storage segment's rates, services and other matters are regulated by FERC. For additional discussion of the Pipeline and Storage segment's rates and regulation, see Item 7, MD&A under the heading "Rate Matters" and Item 8 at Note B-Regulatory Matters.

The discussion under Item 8 at Note B-Regulatory Matters includes a description of the regulatory assets and liabilities reflected on the Company's Consolidated Balance Sheets in accordance with applicable accounting standards. To the extent that the criteria set forth in such accounting standards are not met by the operations of the Utility segment or the Pipeline and Storage segment, as the case may be, the related regulatory assets and liabilities would be eliminated from the Company's Consolidated Balance Sheets and such accounting treatment would be discontinued.

In the International segment, rates charged for the sale of thermal energy and electric energy at the retail level are subject to regulation and audit in the Czech Republic by the Czech Ministry of Finance. The regulation of electric energy rates at the retail level indirectly impacts the rates charged by the International segment for its electric energy sales at the wholesale level.

In addition, the Company and its subsidiaries are subject to the same federal, state and local (including foreign) regulations on various subjects, including environmental matters, as other companies doing similar business in the same locations.

The Utility Segment

The Utility segment contributed approximately 42.1% of the Company's 2002 net income available for common stock.

Additional discussion of the Utility segment appears below in this Item 1 under the headings "Sources and Availability of Raw Materials," "Competition" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Pipeline and Storage Segment

The Pipeline and Storage segment contributed approximately 25.3% of the Company's 2002 net income available for common stock.

Supply Corporation currently has service agreements for substantially all of its firm transportation capacity, which totals approximately 2,075 thousand dekatherms (MDth) per day. The Utility segment accounts for approximately 1,171 MDth per day or 56.4% of the total capacity, and the Energy Marketing segment represents another 85 MDth per day or 4.1% of the total capacity. The remaining 819 MDth or 39.5% of Supply Corporation's firm transportation capacity is subject to firm contracts with nonaffiliated customers.

Supply Corporation has available for sale approximately 68,854 MDth of firm storage capacity. The Utility segment has contracted for 31,395 MDth or 45.6% of the total capacity and the Energy Marketing segment accounts for another 3,955 MDth or 5.7% of the total capacity. Nonaffiliated customers have contracted for the remaining 33,504 MDth or 48.7% of the firm storage capacity. Supply Corporation has been successful in marketing and obtaining executed contracts for storage service (at discounted rates) as it becomes available and expects to continue to do so.*

Additional discussion of the Pipeline and Storage segment appears below under the headings "Sources and Availability of Raw Materials," "Competition" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Exploration and Production Segment

The Exploration and Production segment contributed approximately 22.8% of the Company's 2002 net income available for common stock.

Additional discussion of the Exploration and Production segment appears below under the headings "Sources and Availability of Raw Materials" and "Competition," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The International Segment

The International segment incurred a net loss in 2002. The impact of this segment's net loss in relation to the Company's 2002 net income available for common stock was negative 3.8%.

Additional discussion of the International segment appears below under the heading "Sources and Availability of Raw Materials," "Competition" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Energy Marketing Segment

The Energy Marketing segment contributed approximately 7.3% of the Company's 2002 net income available for common stock.

Additional discussion of the Energy Marketing segment appears below under the headings "Sources and Availability of Raw Materials," "Competition" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data .

The Timber Segment

The Timber segment contributed approximately 8.2% of the Company's 2002 net income available for common stock.

Additional discussion of the Timber segment appears below under the headings "Sources and Availability of Raw Materials," "Competition" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

All Other Category and Corporate Operations

The All Other category and Corporate operations incurred a net loss in 2002. The impact of this net loss in relation to the Company's 2002 net income available for common stock was negative 1.9%.

Additional discussion of the All Other category and Corporate operations appears below in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

Sources and Availability of Raw Materials

Natural gas is the principal raw material for the Utility segment. In 2002, the Utility segment purchased 109.8 billion cubic feet (Bcf) of gas. Gas purchases from various producers and marketers in the southwestern United States and Canada under long-term (two years or longer) contracts accounted for 57% of these purchases. Purchases of gas on the spot market (contracts of less than a year) accounted for 36% of the Utility segment's 2002 gas purchases. Gas purchases from Dynegy Marketing and Trade, Mirant Americas Energy Marketing, LP, BP Energy Company and Anadarko Energy Services Company represented 15%, 13%, 12% and 11%, respectively, of total 2002 gas purchases by the Utility segment. These four producers or marketers provided gas from the southwestern United States under long-term contracts. No other producer or marketer provided the Utility segment with 10% or more of its gas requirements in 2002. Currently, the Utility segment's top suppliers of natural gas are BP Energy Company, Amerada Hess Corp., Conoco Inc., Anadarko Energy Services Company and Occidental Energy Marketing, Inc.

Supply Corporation transports and stores gas owned by its customers, whose gas originates in the southwestern and Appalachian regions of the United States as well as in Canada. Additional discussion of proposed pipeline projects appears below under "Competition: The Pipeline and Storage Segments," in Item 7, MD&A and in Item 8 at Note H - Commitments and Contingencies.

The Exploration and Production segment seeks to discover and produce raw materials (natural gas, oil and hydrocarbon liquids) as further described in this report in Item 7, MD&A and Item 8 at Notes I-Business Segment Information and N - Supplementary Information for Oil and Gas Producing Activities.

Coal is the principal raw material for the International segment, constituting 52% of the cost of raw materials needed in 2002 to operate the boilers which produce steam or hot water. Natural gas, oil, limestone and water combined accounted for the remaining 48% of such materials. Coal is purchased and delivered directly from the adjacent Mostecka Uhelna Spolecnost, a.s. mine in the Czech Republic for Horizon's largest coal-fired plant under a contract where price and quantity are the subject of negotiation each year. The Company has been informed that this mine has proven reserves through 2030.* The Czech Republic government imports natural gas from sources in Russia and the North Sea and transports the gas through the Transgas pipeline system, which is majority owned by RWE AG, a German multi-utility. The International segment purchases natural gas from one of the eight regional gas distribution companies in the Czech Republic. The Czech Republic government also imports oil. The International segment purchases oil from domestic and foreign refineries.

With respect to the Timber segment, Highland requires an adequate supply of timber to process in its sawmill and kiln operations. Seventy percent of the timber processed comes from land owned by Seneca; therefore, the source and availability of this segment's primary raw material are generally known in advance.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2002, this segment purchased 31.5 Bcf of natural gas.

Competition

Competition in the natural gas industry exists among providers of natural gas, as well as between natural gas and other sources of energy. The deregulation of the natural gas industry should continue to enhance the competitive position of natural gas relative to other energy sources, such as fuel oil or electricity, by removing some of the regulatory impediments to adding customers and responding to market forces.* In addition, the environmental advantages of natural gas compared with other fuels should increase the role of natural gas as an energy source.*

The electric industry is moving toward a more competitive environment as a result of the Federal Energy Policy Act of 1992 and initiatives undertaken by the FERC and various states. It remains unclear what impact this restructuring will have on the Company.*

The Company competes on the basis of price, service and reliability, product performance and other factors. Sources and providers of energy, other than those described under this "Competition" heading, do not compete with the Company to any significant extent.*

Competition: The Utility Segment

The changes precipitated by the FERC's restructuring of the gas industry in Order No. 636 continue to reshape the roles of the gas utility industry and the state regulatory commissions. Regulators in both New York and Pennsylvania have adopted retail competition programs for natural gas supply purchases. However, the Utility segment's traditional distribution function remains largely unchanged. For further discussion of state restructuring initiatives refer to Item 7, MD&A under the heading "Rate Matters."

Competition for large-volume customers continues with local producers or pipeline companies attempting to sell or transport gas directly to end-users located within the Utility segment's service territories (i.e., bypass). In addition, competition continues with fuel oil suppliers and may increase with electric utilities making retail energy sales.*

The Utility segment is now better able to compete, through its unbundled flexible services, in its most vulnerable markets (the large commercial and industrial markets).* The Utility segment continues to (i) develop or promote new sources and uses of natural gas or new services, rates and contracts and (ii) emphasize and provide high quality service to its customers.

Competition: The Pipeline and Storage Segment

Supply Corporation competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeastern United States and with other companies providing gas storage services. Supply Corporation has some unique characteristics which enhance its competitive position. Its facilities are located adjacent to Canada and the northeastern United States and provide part of the link between gas-consuming regions of the eastern United States and gas-producing regions of Canada and the southwestern, southern and other continental regions of the United States. This location offers the opportunity for increased transportation and storage services in the future.*

In October 2002, the Company announced that it had signed an agreement to acquire Empire. Empire is a natural gas transmission pipeline that originates at the United States/Canada border at the Chippawa Channel of the Niagara River near Buffalo, New York and extends easterly for 157 miles where it terminates in Central New York just north of Syracuse, New York. Empire competes with other pipelines to transport natural gas from Canada to upstate New York. Refer to Item 7, MD&A under the heading "Capital Resources and Liquidity" and Item 8 at Note H - Commitments and Contingencies for further discussion of Empire.

Supply Corporation and TransCanada PipeLines Limited together are pursuing a proposal to construct a pipeline to transport natural gas from Kirkwall, Ontario to the storage and market hub at Leidy, Pennsylvania. This project, called the Northwinds Pipeline, is competing for customers with other proposed pipeline projects that would bring natural gas from Canada to the markets in the northeast and mid-Atlantic regions of the United States. It is likely that not all of the proposed pipelines will go forward, and that the first project built will have an advantage over other proposed projects.* If completed, the Northwinds Pipeline would likely create opportunities for increased transportation and storage services by Supply Corporation.* For further discussion of the Northwinds Pipeline projects, refer to Item 7, MD&A under the heading "Investing Cash Flow."

Competition: The Exploration and Production Segment

The Exploration and Production segment competes with other gas and oil producers and marketers with respect to sales of oil and gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other oil and natural gas exploration and production companies of various sizes for leases and drilling rights for exploration and development prospects.

To compete in this environment, Seneca and its wholly-owned subsidiaries NFE and Player, each originate and act as operator on most prospects, minimize risk of exploratory efforts through partnership-type arrangements, apply the latest technology for both exploratory studies and drilling operations, and focus on market niches that suit their size, operating expertise and financial criteria.

Competition: The International Segment

Horizon competes with other entities seeking to develop or acquire foreign and domestic energy projects. Horizon, through UE, faces competition in the sale of thermal energy. Most customers can opt to install boilers to produce their thermal energy, rather than purchase thermal energy from the district heating system. In addition, UE faces competition in the sale of electricity. UE must submit price bids on an annual basis for the sale of its electricity to the regional distribution company. A large percentage of the electricity purchased by the regional distribution companies is produced by the Czech Republic's dominant state-owned energy producer. UE sells electricity at the wholesale level.

Competition: The Energy Marketing Segment

The Energy Marketing segment competes with other marketers of natural gas and with other providers of energy management services. Although the deregulation of natural gas utilities is a relatively new occurrence, the competition in this area is well developed with regard to price and services from both local and regional marketers.

Competition: The Timber Segment

With respect to the Timber segment, Highland competes with other sawmill operations and with other suppliers of timber, logs and lumber. These competitors may be local, regional, national or international in scope. This competition, however, is primarily limited to those entities which either process or supply high quality hardwoods species such as cherry, oak and maple as veneer logs, saw logs, export logs or lumber ultimately used in the production of high-end furniture, cabinetry and flooring. The Timber segment sells its products both nationally and internationally.

Seasonality

Variations in weather conditions can materially affect the volume of gas delivered by the Utility segment, as virtually all of its residential and commercial customers use gas for space heating. The effect that this has on Utility segment revenues in New York is mitigated by a weather normalization clause which is designed to adjust the rates of retail customers to reflect the impact of deviations from normal weather. Weather that is more than 2.2% warmer than normal results in a surcharge being added to customers' current bills, while weather that is more than 2.2% colder than normal results in a refund being credited to customers' current bills.

Volumes transported and stored by Supply Corporation may vary materially depending on weather, without materially affecting its revenues. Supply Corporation's rates are based on a straight fixed-variable rate design which allows recovery of fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed only to reimburse the variable costs caused by actual transportation or storage of gas.

Variations in weather conditions can materially affect the volume of gas consumed by customers of the Energy Marketing segment and the amount of thermal energy consumed by the heating customers of the International segment. Volume variations can have a corresponding impact on revenues within these segments.

The activities of the Timber segment vary on a seasonal basis and are subject to weather constraints. The timber harvesting and processing season occurs when timber growth is dormant and runs from approximately September to March. The operations conducted in the summer months focus on pulpwood and on thinning out lower-grade species from the timber stands to encourage the growth of higher-grade species.

Capital Expenditures

A discussion of capital expenditures by business segment is included in Item 7, MD&A under the heading "Investing Cash Flow."

Environmental Matters

A discussion of material environmental matters involving the Company is included in Item 7, MD&A under the heading "Other Matters" and in Item 8, Note H-Commitments and Contingencies.

Miscellaneous

The Company and its wholly-owned or majority-owned subsidiaries had a total of 3,177 full-time employees at September 30, 2002, with 2,233 employees in all of its U.S. operations and 944 employees in its international operations. This is a decrease of 1.8% from the 3,235 total employed at September 30, 2001.

Agreements covering employees in collective bargaining units in New York were renegotiated, effective as of November 2000, and are scheduled to expire in February 2006. Certain agreements covering employees in collective bargaining units in Pennsylvania were renegotiated, effective November 1998, and are scheduled to expire in May 2003. Other agreements covering employees in collective bargaining units in Pennsylvania were renegotiated, effective October 1, 2002, and are scheduled to expire in April 2007. An agreement covering employees in collective bargaining units in the Czech Republic was renegotiated in 2001 and is scheduled to expire in 2004.

The Utility segment has numerous municipal franchises under which it uses public roads and certain other rights-of-way and public property for the location of facilities. When necessary, the Utility segment renews such franchises.

The Company's Internet Address is www.nationalfuelgas.com. This reference to the Company's Internet address shall not, under any circumstances, be deemed to incorporate the information available at such Internet address into this Form 10-K. The information available at the Company's Internet address is not part of this Form 10-K or any other report filed by the Company with the SEC.

Executive Officers of the Company as of November 15, 2002[1]

Name and Age [2]	Current Company Positions and Other Material Business Experience During Past Five Years [3]
Philip C. Ackerman (58)	Chairman of the Board of Directors since January 2002; Chief Executive Officer since October 2001; President since July 1999; and President of Horizon since September 1995. Mr. Ackerman has served as a Director since March 1994, and previously served as Senior Vice President from June 1989 to July 1999 and President of Distribution Corporation from October 1995 to July 1999.
Dennis J. Seeley (59)	President of Supply Corporation since March 2000; Senior Vice President of Distribution Corporation since February 1997. Mr. Seeley has served as Vice President of the Company from January 2000 to April 2000 and Senior Vice President of Supply Corporation from January 1993 to February 1997.
David F. Smith (49)	President of Distribution Corporation since July 1999; Senior Vice President of Supply Corporation since July 2000. Mr. Smith served as Senior Vice President of Distribution Corporation from January 1993 to July 1999.
James A. Beck (55)	President of Seneca since October 1996 and President of Highland since March 1998. Mr. Beck previously served as Vice President of Seneca from January 1994 to April 1995 and Executive Vice President of Seneca from May 1995 to September 1996.
Gerald T. Wehrlin (64)	President of NFR since May 2001; Controller of the Company since December 1980; and Vice President of Horizon since February 1997. Mr. Wehrlin previously served as Senior Vice President of Distribution Corporation from April 1991 to May 2001 and as Secretary and Treasurer of Horizon from September 1995 to February 1997.
Bruce H. Hale (53)	President of Horizon Power since March 2001; Senior Vice President of Supply Corporation since February 1997; and Vice President of Horizon since September 1995. Mr. Hale previously served as Senior Vice President of Distribution Corporation from January 1993 to February 1997.
Joseph P. Pawlowski (61)	Treasurer since December 1980; Senior Vice President of Distribution Corporation since February 1992 and Treasurer of Distribution Corporation since January 1981; Treasurer of Supply Corporation since June 1985; and Secretary of Supply Corporation since October 1995.
Walter E. DeForest (61)	Senior Vice President of Distribution Corporation since August 1993; and Senior Vice President of Supply Corporation from January 1992 to August 1993.
Anna Marie Cellino (49)	Senior Vice President of Distribution Corporation since July 2001; Vice President of Distribution Corporation from June 1994 to July 2001; and Secretary of the Company since October 1995.
Ronald J. Tanski (50)	Senior Vice President of Distribution Corporation since July 2001; Controller of Distribution Corporation since February 1997; Secretary and Treasurer of Horizon since February 1997; and Vice President of Distribution Corporation from April 1993 to July 2001.
John R. Pustulka (50)	Senior Vice President of Supply Corporation since July 2001; and Vice President of Supply Corporation from April 1993 to July 2001.
James D. Ramsdell (47)	Senior Vice President of Distribution Corporation since July 2001; and Vice President of Distribution Corporation from June 1994 to July 2001.

(1) The Company has been advised that there are no family relationships among any of the officers listed, and that there is no arrangement or understanding among any one of them and any other persons pursuant to which he or she was elected as an officer. The executive officers serve at the pleasure of the Board of Directors.
(2) Ages are as of September 30, 2002.
(3) The information provided relates to the principal subsidiaries of the Company. Many of the executive officers have served or currently serve as officers or directors for other subsidiaries of the Company.

ITEM 2 PROPERTIES

General Information on Facilities

The investment of the Company in net property, plant and equipment was $2.8 billion at September 30, 2002. Approximately 51% of this investment was in the Utility and Pipeline and Storage segments, which are primarily located in western New York and northwestern Pennsylvania. The Exploration and Production segment, which is the next largest investment in net property, plant and equipment (38%), is primarily located in California, in the Appalachian region of the United States, in Wyoming, in the Gulf Coast region of Texas and Louisiana and in the provinces of Manitoba, Alberta, Saskatchewan and British Columbia in Canada. The remaining investment in net property, plant and equipment consisted primarily of the International segment (7%) which is located in the Czech Republic and the Timber segment (4%) which is located primarily in northwestern Pennsylvania. During the past five years, the Company has made significant additions to property, plant and equipment in order to augment the reserve base of oil and gas in the United States and Canada, to expand and improve transmission and distribution facilities for both retail and transportation customers, and to purchase district heating and power generation facilities in the Czech Republic. Net property, plant and equipment has increased $1.025 billion, or 56%, since 1997.

The Utility segment had a net investment in property, plant and equipment of $960.0 million at September 30, 2002. The net investment in its gas distribution network (including 14,783 miles of distribution pipeline) and its service connections to customers represent approximately 57% and 29%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2002.

The Pipeline and Storage segment had a net investment of $487.8 million in property, plant and equipment at September 30, 2002. Transmission pipeline, with a net cost of $148.1 million, represents 30% of this segment's total net investment and includes 2,471 miles of pipeline required to move large volumes of gas throughout its service area. Storage facilities consist of 32 storage fields, four of which are jointly operated with certain pipeline suppliers, and 439 miles of pipeline. Net investment in storage facilities includes $87.7 million of gas stored underground-noncurrent, representing the cost of the gas required to maintain pressure levels for normal operating purposes as well as gas maintained for system balancing and other purposes, including that needed for no-notice transportation service. The Pipeline and Storage segment has 29 compressor stations with 75,306 installed compressor horsepower.

The Exploration and Production segment had a net investment in property, plant and equipment of $1.072 billion at September 30, 2002. Of this amount, $814 million relates to properties located in the United States. The remaining net investment of $258 million relates to properties located in Canada.

The International segment had a net investment in property, plant and equipment of $207.2 million at September 30, 2002. This represents UE's net investment in district heating and electric generation facilities.

The Timber segment had a net investment in property, plant and equipment of $110.6 million at September 30, 2002. Located primarily in northwestern Pennsylvania, the net investment includes three sawmills and approximately 155,000 acres of land and timber.

The Utility and Pipeline and Storage segments' facilities provided the capacity to meet the Company's 2002 peak day sendout, including transportation service, of 1,568.0 million cubic feet (MMcf), which occurred on February 4, 2002. Withdrawals from storage of 682.8 MMcf provided approximately 43.5% of the requirements on that day.

Company maps are included in exhibit 99.5 of this Form 10-K.

Exploration and Production Activities

The information that follows is disclosed in accordance with SEC regulations, and relates to the Company's oil and gas producing activities. A further discussion of oil and gas producing activities is included in Item 8, Note N-Supplementary Information for Oil and Gas Producing Activities. Note N sets forth proved developed and undeveloped reserve information for Seneca. During 2002, Seneca's proved developed and undeveloped reserves decreased significantly. Natural gas reserves decreased from 322 Bcf at September 30, 2001 to 258 Bcf at September 30, 2002 and oil reserves decreased from 115,328 thousands of barrels (Mbbl) to 99,717 Mbbl. These decreases can be attributed to several factors: (i) production and sales of properties (refer to Item 7, MD&A), (ii) limited drilling activity off-shore in the Gulf of Mexico which resulted in a reserve replacement of only 56% of consolidated production (the Company is shifting its emphasis from short-lived off-shore reserves to longer-lived on-shore reserves), and (iii) a determination that certain development drilling programs in California and Canada were uneconomic (reflected in Note N as revisions of previous estimates). Seneca's oil and gas reserves reported in Note N as of September 30, 2002 were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Ralph E. Davis Associates, Inc. Seneca reports its oil and gas reserve information on an annual basis to the Energy Information Administration (EIA). The basis of reporting Seneca's reserves to the EIA is identical to that reported in Note N.

The following is a summary of certain oil and gas information taken from Seneca's records. All monetary amounts are expressed in U.S. dollars.

PRODUCTION

For the Year Ended September 30	2002	2001	2000
United States			
Average Sales Price per Mcf of Gas[1]	$2.99	$5.53	$3.31
Average Sales Price per Barrel of Oil[1]	$21.03	$25.43	$25.34
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$0.67	$0.55	$0.51
Canada			
Average Sales Price per Mcf of Gas[1]	$2.29	$2.41	$2.52
Average Sales Price per Barrel of Oil[1]	$19.94	$24.29	$29.28
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$1.29	$1.34	$1.41
Total			
Average Sales Price per Mcf of Gas[1]	$2.88	$5.39	$3.31
Average Sales Price per Barrel of Oil[1]	$20.63	$24.99	$26.03
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$0.84	$0.73	$0.58

(1) Prices do not reflect gains or losses from hedging activities.

PRODUCTIVE WELLS

		United States		Canada		Total	
At September 30, 2002		Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells	– gross	1,877	1,167	160	668	2,037	1,835
	– net	1,763	1,144	100	605	1,863	1,749

DEVELOPED AND UNDEVELOPED ACREAGE

At September 30, 2002		United States	Canada	Total
Developed Acreage	– gross	644,109	148,557	792,666
	– net	577,463	113,800	691,263
Undeveloped Acreage	– gross	792,696	781,645	1,574,341
	– net	581,584	700,811	1,282,395

DRILLING ACTIVITY

For the Year Ended September 30		Productive			Dry		
		2002	2001	2000	2002	2001	2000
United States							
Net Wells Completed	– Exploratory	4.27	11.83	13.89	4.67	4.93	6.53
	– Development	75.30	108.60	82.82	2.10	1.00	1.00
Canada							
Net Wells Completed	– Exploratory	0.20	10.00	1.00	4.00	11.00	—
	– Development	33.70	61.14	21.50	7.90	2.75	4.00
Total							
Net Wells Completed	– Exploratory	4.47	21.83	14.89	8.67	15.93	6.53
	– Development	109.00	169.74	104.32	10.00	3.75	5.00

PRESENT ACTIVITIES

At September 30, 2002		United States	Canada	Total
Wells in Process of Drilling	– gross	38.00	11.00	49.00
	– net	34.58	11.00	45.58

South Lost Hills Waterflood Program

In Seneca's South Lost Hills Field, a waterflood project was initiated in 1996 on the Ellis lease in the Diatomite reservoir for pressure maintenance and recovery enhancement purposes. Currently there are 21 injection wells and 89 production wells in the program. The total injection and production from this waterflood project is 4,200 barrels of water per day and 230 barrels of oil per day, respectively.

ITEM 3 LEGAL PROCEEDINGS

In an action instituted in the New York State Supreme Court, Chautauqua County on January 31, 2000 against Seneca Resources Corporation ("Seneca"), National Fuel Resources, Inc., and "National Fuel Gas Corporation," Donald J. and Margaret Ortel and Brian and Judith Rapp, "individually and on behalf of all those similarly situated," allege, in an amended complaint which adds National Fuel Gas Company as a party defendant (a) that Seneca underpaid royalties due under leases operated by it, and (b) that Seneca's co-defendants (i) fraudulently participated in and concealed such alleged underpayment, and (ii) induced Seneca's alleged breach of such leases. Plaintiffs seek an accounting, declaratory and related injunctive relief, and compensatory and exemplary damages. Defendants have denied each of plaintiffs' material substantive allegations and set up twenty-five affirmative defenses in separate verified answers.

A motion was made by plaintiffs on July 15, 2002 to certify a class comprising all persons presently and formerly entitled to receive royalties on the sale of natural gas produced and sold from wells operated in New York by Seneca (and its predecessor Empire Exploration, Inc).

The defendants responded to that motion in August 2002. An oral argument on that motion took place in September 2002. The court has not yet entered a decision on the motion. If a class is certified, discovery would begin on the merits of the claims, and the case eventually tried or settled. The Company believes, based on the information presently known, that the ultimate resolution of this matter will not be material to the consolidated financial condition, results of operations, or cash flow of the Company.* No assurances can be given, however, as to the ultimate outcome of this matter, and it is possible that the outcome could be material to results of operations or cash flow for a particular quarter or annual period.

For a discussion of various environmental and other matters, refer to Item 7, MD&A and Item 8 at Note H-Commitments and Contingencies.

The Company is involved in litigation arising in the normal course of business. Also in the normal course of business, the Company is involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While the resolution of such litigation or regulatory matters could have a material effect on earnings and cash flows in the period of resolution, none of this litigation, and none of these regulatory matters, are expected to change materially the Company's present liquidity position, nor have a material adverse effect on the financial condition of the Company.

ITEM 4 SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matter was submitted to a vote of security holders during the fourth quarter of 2002.

Part II

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

Information regarding the market for the Company's common equity and related stockholder matters appears under Item 12 at Securities Authorized for Issuance Under Equity Compensation Plans, Item 8 at Note D-Capitalization and Note M-Market for Common Stock and Related Shareholder Matters (unaudited).

On July 1, 2002, the Company issued a total of 1,920 unregistered shares of Company common stock to the eight non-employee directors then serving on the Board of Directors, 240 shares to each such director. On September 12, 2002, Rolland E. Kidder, Executive Director of the Robert H. Jackson Center for Justice in Jamestown, New York, was elected to the Board of Directors of the Company, and on September 25, 2002, the Company issued 50 unregistered shares of Company common stock to Mr. Kidder. All of these unregistered shares issued on July 1, 2002 and September 25, 2002 were issued as partial consideration for the directors' services during the quarter ended September 30, 2002, pursuant to the Company's Retainer Policy for Non-Employee Directors. These transactions were exempt from registration under Section 4(2) of the Securities Act of 1933, as transactions not involving a public offering.

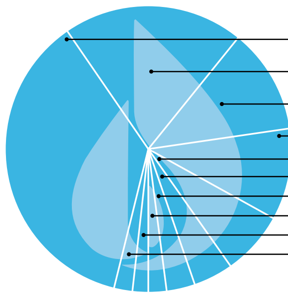
ITEM 6 SELECTED FINANCIAL DATA

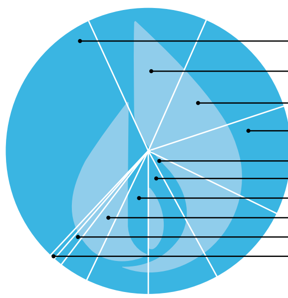
Year Ended September 30	2002	2001	2000	1999	1998
Summary of Operations *(Thousands)*					
Operating Revenues	**$1,464,496**	$2,059,836	$1,412,416	$1,254,402	$1,248,000
Operating Expenses:					
Purchased Gas	**462,857**	1,002,466	488,383	397,053	441,746
Fuel Used in Heat and Electric Generation	**50,635**	54,968	54,893	55,788	37,837
Operation and Maintenance	**394,157**	364,318	350,383	328,800	321,411
Property, Franchise and Other Taxes	**72,155**	83,730	78,878	91,146	92,817
Depreciation, Depletion and Amortization	**180,668**	174,914	142,170	124,778	117,238
Impairment of Oil and Gas Producing Properties	**—**	180,781	—	—	128,996
Income Taxes	**72,034**	37,106	77,068	64,829	24,024
	1,232,506	1,898,283	1,191,775	1,062,394	1,164,069
Operating Income	**231,990**	161,553	220,641	192,008	83,931
Operations of Unconsolidated Subsidiaries:					
Income	**224**	1,794	1,669	999	319
Impairment of Investment in Partnership	**(15,167)**	—	—	—	—
	(14,943)	1,794	1,669	999	319
Other Income	**7,017**	10,639	6,366	11,344	35,551
Income Before Interest Charges and Minority Interest in Foreign Subsidiaries	**224,064**	173,986	228,676	204,351	119,801
Interest Charges	**105,652**	107,145	100,085	87,698	85,284
Minority Interest in Foreign Subsidiaries	**(730)**	(1,342)	(1,384)	(1,616)	(2,213)
Income Before Cumulative Effect	**117,682**	65,499	127,207	115,037	32,304
Cumulative Effect of Change in Accounting	**—**	—	—	—	(9,116)
Net Income Available for Common Stock	**$117,682**	$65,499	$127,207	$115,037	$23,188
Per Common Share Data					
Basic Earnings per Common Share	**$1.47**(1)	$0.83(2)	$1.63	$1.49	$0.30(3)
Diluted Earnings per Common Share	**$1.46**(1)	$0.82(2)	$1.61	$1.47	$0.30(3)
Dividends Declared	**$1.03**	$0.99	$0.95	$0.92	$0.89
Dividends Paid	**$1.02**	$0.97	$0.94	$0.91	$0.88
Dividend Rate at Year-End	**$1.04**	$1.01	$0.96	$0.93	$0.90
At September 30:					
Number of Common Shareholders	**20,004**	20,345	21,164	22,336	23,743
Net Property, Plant and Equipment *(Thousands)*					
Utility	**$960,015**	$945,693	$939,753	$919,642	$906,754
Pipeline and Storage	**487,793**	483,222	474,972	466,524	460,952
Exploration and Production	**1,072,200**	1,081,622	998,852	674,813	638,886
International	**207,191**	178,250	172,602	210,920	202,590
Energy Marketing	**125**	262	360	489	353
Timber	**110,624**	90,453	95,607	88,623	38,593
All Other	**6,797**	1,209	1,241	214	—
Corporate	**—**	2	4	7	9
Total Net Plant	**$2,844,745**	$2,780,713	$2,683,391	$2,361,232	$2,248,137
Total Assets *(Thousands)*	**$3,401,309**	$3,445,231	$3,251,031	$2,842,586	$2,684,459
Capitalization *(Thousands)*					
Comprehensive Shareholders' Equity	**$1,006,858**	$1,002,655	$987,437	$939,293	$890,085
Long-Term Debt, Net of Current Portion	**1,145,341**	1,046,694	953,622	822,743	693,021
Total Capitalization	**$2,152,199**	$2,049,349	$1,941,059	$1,762,036	$1,583,106

(1) 2002 includes impairment of investment in partnership of ($0.12) basic and diluted.
(2) 2001 includes oil and gas asset impairment of ($1.32) basic, ($1.29) diluted.
(3) 1998 includes oil and gas asset impairment of ($1.03) basic, ($1.02) diluted and cumulative effect of a change in depletion methods of ($0.12) basic and diluted.

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

The Revenue Dollar – 2002





Results of Operations

Critical Accounting Policies

The Company has prepared its consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.* In the event estimates or assumptions prove to be different from actual results, adjustments are made in subsequent periods to reflect more current information. The following is a summary of the Company's most critical accounting policies, which are defined as those policies whereby judgments or uncertainties could affect the application of those policies and materially different amounts could be reported under different conditions or using different assumptions. For a complete discussion of the Company's significant accounting policies, refer to Item 8 at Note A - Summary of Significant Accounting Policies.

Oil and Gas Exploration and Development Costs. In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this accounting methodology, all costs associated with property acquisition, exploration, and development activities are capitalized, including internal costs directly identified with acquisition, exploration, and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities.

The Company believes that determining the amount of the Company's proved reserves is a critical accounting estimate. Proved reserves are estimated quantities of reserves that, based on geologic and engineering data, appear with reasonable certainty to be producible under existing economic and operating conditions. Such estimates of proved reserves are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The estimates involved in determining proved reserves are critical accounting estimates because they serve as the basis over which capitalized costs are depleted under the full-cost method of accounting (on a unit-of-production basis). Unevaluated properties are excluded from depletion until it is determined whether or not there are proved reserves that can be assigned to these properties. Once it is determined whether there are proved reserves or not, these costs are transferred to the costs being depleted.

In addition to depletion under the units-of-production method, proved reserves are a major component in the Securities and Exchange Commission (SEC) full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed on a country-by-country basis and determines a limit, or ceiling, to the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net revenues using a discount factor of 10%, which is computed by applying current market prices of oil and gas to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income taxes. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling, a non-cash impairment must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write-down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. The Company recorded a non-cash impairment relating to its Canadian properties in 2001. This impairment amounted to $104.0 million (after tax) and resulted from low oil and gas prices at September 30, 2001.

Regulation. The Company is subject to regulation by certain state and federal authorities. The Company, in its Utility and Pipeline and Storage segments, has accounting policies which conform to Statement of Financial Accounting Standards No. 71, "Accounting for the Effect of Certain Types of Regulation" and which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows the Company to defer expenses and income on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the income statement by an unregulated company. These deferred regulatory assets and liabilities are then flowed through the income statement in the period in which the same amounts are reflected in rates. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item.

Accounting for Derivative Financial Instruments. The Company, primarily in its Exploration and Production and Energy Marketing segments, uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments can be categorized as price swap agreements, no cost collars, options and futures contracts. In accordance with the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities", the Company accounts for these instruments as effective cash flow hedges or fair value hedges. As such, gains or losses associated with the derivative financial instruments are matched with gains or losses resulting from the underlying physical transaction that is being hedged. To the extent that the derivative financial instruments would ever be deemed to be ineffective, gains or losses from the derivative financial instruments would be marked-to-market on the income statement without regard to an underlying physical transaction.

The Company uses both exchange-traded and non exchange-traded derivative financial instruments. The fair value of the non exchange-traded derivative financial instruments are based on valuations determined by the counterparties.

Pension and Other Post-Retirement Benefits. The amounts reported in the Company's financial statements related to its pension and other post-retirement benefits are determined on an actuarial basis, which uses many assumptions in the calculation of such amounts. These assumptions include the discount rate, the expected return on plan assets, the rate of compensation increase and, for other post-retirement benefits, the expected annual rate of increase in per capita cost of covered medical and prescription benefits. Changes in actuarial assumptions and actuarial experience could have a material impact on the amount of pension and post-retirement benefit costs and funding requirements experienced by the Company.* However, the Company expects to recover substantially all of its net periodic pension and other post-retirement benefit costs attributable to employees in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorization.* For financial reporting purposes, the difference between the amounts of pension cost and post-retirement benefit cost recoverable in rates and the amounts of such costs as determined under applicable accounting principles is recorded as either a regulatory asset or liability, as appropriate, as discussed above under "Regulation."

Earnings

2002 Compared with 2001

The Company's earnings were $117.7 million, or $1.47 per common share ($1.46 per common share on a diluted basis) in 2002. This compares with earnings of $65.5 million, or $0.83 per common share ($0.82 per common share on a diluted basis) in 2001. However, earnings in 2002 included a non-cash impairment of the Company's investment in the Independence Pipeline project in the Pipeline and Storage segment in the amount of $9.9 million (after tax), or $0.12 per common share (basic and diluted). Earnings in 2001 included a non-cash impairment of oil and gas assets in the Exploration and Production segment in the amount of $104.0 million (after tax), or $1.32 per common share ($1.29 per common share on a diluted basis), which is discussed above under Critical Accounting Policies - Oil and Gas Exploration and Development Costs. Without these non-cash impairments, earnings for 2002 would have been $127.5 million, or $1.59 per common share ($1.58 per common share on a diluted basis) and earnings for 2001 would have been $169.5 million, or $2.14 per common share ($2.11 per common share on a diluted basis). The decrease in earnings of $42.0 million (exclusive of the non-cash impairments) is primarily the result of lower earnings in the Exploration and Production segment. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows.

2001 Compared with 2000

The Company's earnings were $65.5 million, or $0.83 per common share ($0.82 per common share on a diluted basis) in 2001. This compares with 2000 earnings of $127.2 million, or $1.63 per common share ($1.61 per common share on a diluted basis). However, 2001 earnings included a non-cash impairment of oil and gas assets in the Exploration and Production segment in the amount of $104.0 million (after tax), or $1.32 per common share ($1.29 per common share on a diluted basis). Without this non-cash impairment, earnings for 2001 would have been $169.5 million, or $2.14 per common share ($2.11 per common share on a diluted basis). The increase in earnings of $42.3 million (exclusive of the non-cash impairment) was primarily the result of higher earnings in the Exploration and Production segment. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows.

EARNINGS (LOSS) BY SEGMENT

Year Ended September 30 (Thousands)	2002	2001	2000
Utility	**$49,505**	$60,707	$57,662
Pipeline and Storage (1)	**29,715**	40,377	31,614
Exploration and Production (2)	**26,851**	(32,284)	34,877
International	**(4,443)**	(3,042)	3,282
Energy Marketing	**8,642**	(3,432)	(7,790)
Timber	**9,689**	7,715	6,133
Total Reportable Segments	**119,959**	70,041	125,778
All Other	**(885)**	(4,277)	(371)
Corporate	**(1,392)**	(265)	1,800
Total Consolidated (1) (2)	**$117,682**	$65,499	$127,207

(1) Exclusive of the non-cash asset impairment of the Company's investment in the Independence Pipeline project, 2002 earnings for the Pipeline and Storage segment, and Total Consolidated would have been $39,574 and $127,541, respectively.
(2) Exclusive of the non-cash asset impairment of oil and gas assets, 2001 earnings for the Exploration and Production segment and Total Consolidated would have been $71,756 and $169,539, respectively.

Utility

Revenues

UTILITY OPERATING REVENUES

Year Ended September 30 (Thousands)	2002	2001	2000
Retail Revenues:			
Residential	**$538,345**	$875,050	$584,618
Commercial	**86,963**	154,266	93,914
Industrial	**18,332**	29,110	21,543
	643,640	1,058,426	700,075
Off-System Sales	**68,606**	84,078	47,962
Transportation	**83,267**	89,037	104,534
Other	**(1,292)**	3,106	(6,112)
	$794,221	$1,234,647	$846,459

UTILITY THROUGHPUT – MILLION CUBIC FEET (MMCF)

Year Ended September 30	2002	2001	2000
Retail Sales:			
Residential	**64,639**	73,530	68,196
Commercial	**11,549**	13,831	12,312
Industrial	**3,715**	4,089	4,276
	79,903	91,450	84,784
Off-System Sales	**21,541**	12,736	12,833
Transportation	**61,909**	66,283	71,862
	163,353	170,469	169,479

2002 Compared with 2001

Operating revenues for the Utility segment decreased $440.4 million in 2002 compared with 2001. This decrease largely resulted from a $414.8 million decrease in retail gas sales revenues. Off-system sales revenues, transportation revenues, and other revenues also decreased by $15.5 million, $5.8 million and $4.3 million, respectively.

The decrease in retail gas sales revenues for the Utility segment was largely a function of the recovery of lower gas costs (gas costs are recovered dollar for dollar in revenues) resulting from a much lower cost of purchased gas. See further discussion of purchased gas below under the heading "Purchased Gas." The decrease also resulted from a decrease in retail sales volumes, as shown above. Warmer weather, as shown in the table below, and a general economic downturn in the Utility segment's sales territory were major factors for the decrease in retail sales volumes. Warmer weather and the general economic downturn were also factors in the decrease in transportation revenues and volumes. The decrease in off-system sales revenues was largely due to lower gas prices, which more than offset higher volumes. However, due to profit sharing with retail customers, the margins resulting from off-system sales were minimal.

The decrease in other revenues primarily reflects estimated refund provisions recorded in 2002 and 2001 amounting to $5.3 million and $2.0 million, respectively, recorded in the Utility's New York jurisdiction under an earnings sharing mechanism. This earnings sharing mechanism, which is in accordance with the three-year rate settlement reached with the NYPSC that went into effect October 1, 2000 (New York Rate Settlement), requires the Utility to share with customers 50% of earnings above a predetermined amount. The final refund for the New York Rate Settlement will not be known until the end of 2003.

Partly offsetting the decreases to revenue discussed above was the positive impact of a lower bill credit in the Utility's New York jurisdiction. In connection with the New York Rate Settlement, the Utility's New York customers received a $10.0 million rate decrease in the form of a bill credit for the November 1, 2000 through March 31, 2001 heating season. For the November 1, 2001 through March 31, 2002 heating season, the amount of the bill credit was reduced to $5.0 million.

2001 Compared with 2000

Operating revenues for the Utility segment increased $388.2 million in 2001 compared with 2000. This resulted from an increase in retail and off-system gas sales revenues of $358.4 million and $36.1 million, respectively. Other operating revenues also increased by $9.2 million. These increases were partly offset by a decrease in transportation revenues of $15.5 million.

The increase in retail gas sales revenues for the Utility segment was largely a function of the recovery of higher gas costs, coupled with an increase in retail sales volumes, as shown above. The recovery of higher gas costs resulted from a much higher cost of purchased gas. See further discussion of purchased gas below under the heading "Purchased Gas." The increase in retail sales volumes was primarily the result of the migration of residential and small commercial customers from transportation service to retail service in both the New York and Pennsylvania jurisdictions, coupled with the impact of colder weather. This migration from transportation service resulted from one marketer entering bankruptcy proceedings, another marketer exiting the residential market, and the conclusion of a marketer pilot program in Pennsylvania. Off-system sales revenues increased because of higher gas prices. The decrease in transportation revenues and volumes was primarily due to the migration from transportation service discussed above and the fact that certain commercial and industrial customers were reducing usage due to a slowing economy or they were fuel switching.

The increase in other operating revenues was due primarily to $5.5 million of various revenue reductions in 2000 that did not recur in 2001 (of which $2.2 million was offset by lower operation and maintenance expense in 2000). These revenue reductions related to the September 30, 2000 conclusion of the 1998 two-year rate settlement approved by the NYPSC. In addition to these adjustments, a $3.5 million lower provision for refund was recorded in 2001 as compared with 2000. The provision for refund in 2000 related to the conclusion of the 1998 two-year rate settlement and the provision for refund in 2001 related to the three-year rate settlement approved by the NYPSC in October 2000 (referred to above as New York Rate Settlement).

Revenues in 2001 as compared to revenues in 2000 were reduced by a $10.0 million rate decrease for the Utility's New York customers that went into effect October 1, 2000 in connection with the aforementioned New York Rate Settlement. This rate decrease was provided in the form of a bill credit included in rates during the November 1, 2000 through March 31, 2001 heating season.

Earnings

2002 Compared with 2001

The Utility segment's earnings in 2002 were $49.5 million, a decrease of $11.2 million when compared with the earnings of $60.7 million in 2001. However, the earnings for 2001 included $3.1 million of non-recurring earnings associated with stock appreciation rights (refer to Item 8 at Note D - Capitalization for a discussion of the November 2001 cancellation of stock appreciation rights) and $4.2 million of non-recurring after tax expense associated with early retirement offers in the Utility's New York and Pennsylvania jurisdictions. Exclusive of these two items, the decrease in earnings was $12.3 million. Warmer weather in the Pennsylvania jurisdiction and lower normalized usage per account (normalized usage excludes the impact of weather on consumption) across the Utility's service territory due to a downturn in the economy significantly decreased earnings in 2002. Also contributing to the decrease were several routine regulatory true-up adjustments associated with income taxes, lost and unaccounted for gas and interest expense. The impact of the refund provision discussed above was largely offset by lower operation and maintenance expenses, primarily labor. The impact of the lower bill credit ($5.0 million pre tax and $3.3 million after tax), discussed above, partly offset these decreases.

The impact of weather on the Utility segment's New York rate jurisdiction is tempered by a weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment's New York customers. In 2002, the WNC in New York preserved earnings of approximately $9.9 million (after tax) as weather, overall in the New York service territory, was warmer than normal for the period from October 2001 through May 2002. Since the Pennsylvania jurisdiction does not have a WNC, uncontrollable weather variations directly impact earnings. In the Pennsylvania service territory, weather during 2002 was 16.0% warmer than 2001 and 13.2% warmer than normal.

2001 Compared with 2000

In the Utility segment, 2001 earnings were $60.7 million, up $3.0 million from the prior year. However, the earnings for 2001 included $4.2 million of non-recurring after tax expense associated with early retirement offers in the Utility's New York and Pennsylvania jurisdictions, and the earnings for 2000 included $2.2 million of non-recurring after tax revenue adjustments ($3.3 million pretax) related to the conclusion of the 1998 two-year rate settlement, as discussed in the revenue section above. Stock appreciation rights also had a significant impact on earnings as 2001 had earnings of $3.1 million and 2000 had $3.0 million of after tax expense. This was due to a significant change in the market price of the Company's common stock as the market price increased significantly in 2000 followed by a significant decrease in the market price in 2001. Exclusive of these four items, there was actually a decrease in earning of $1.1 million. A main reason for the decrease was the $10.0 million rate decrease in the Utility segment's New York jurisdiction, as previously discussed, which more than offset the positive earnings impact of colder weather in the Utility segment's Pennsylvania jurisdiction.

In 2001, the WNC in New York preserved earnings of approximately $1.2 million (after tax) as weather, overall in the New York service territory, was warmer than normal for the period from October 2000 through May 2001. In the Pennsylvania service territory, which does not have a WNC, weather during 2001 was 12.3% colder than 2000 and 2.8% colder than normal.

DEGREE DAYS

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Percent (Warmer) Colder Than Prior Year
2002:	**Buffalo**	**6,847**	**5,808**	**(15.2%)**	**(12.6%)**
	Erie	**6,146**	**5,334**	**(13.2%)**	**(16.0%)**
2001:	Buffalo	6,865	6,648	(3.2%)	5.3%
	Erie	6,179	6,351	2.8%	12.3%
2000:	Buffalo	6,932	6,312	(8.9%)	2.1%
	Erie	6,230	5,657	(9.2%)	0.9%

Purchased Gas

The cost of purchased gas is the Company's single largest operating expense. Annual variations in purchased gas costs can be attributed directly to changes in gas sales volumes, the price of gas purchased and the operation of purchased gas adjustment clauses.

Currently, Distribution Corporation has contracted for long-term firm transportation capacity with Supply Corporation and six other upstream pipeline companies for long-term gas supplies with a combination of producers and marketers and for storage service with Supply Corporation and three nonaffiliated companies. In addition, Distribution Corporation can satisfy a portion of its gas requirements through spot market purchases. Changes in wellhead prices have a direct impact on the cost of purchased gas. Distribution Corporation's average cost of purchased gas, including the cost of transportation and storage, was $4.68 per thousand cubic feet (Mcf) in 2002, a decrease of 36% from the average cost of $7.35 per Mcf in 2001. The average cost of purchased gas in 2001 was 49% higher than the $4.93 per Mcf in 2000. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

Pipeline and Storage

Revenues

PIPELINE AND STORAGE OPERATING REVENUES

Year Ended September 30 (Thousands)	2002	2001	2000
Firm Transportation	**$88,082**	$91,611	$92,305
Interruptible Transportation	**3,315**	1,917	1,578
	91,397	93,528	93,883
Firm Storage Service	**62,733**	61,559	62,899
Interruptible Storage Service	**7**	670	287
	62,740	62,229	63,186
Other	**13,247**	15,334	12,590
	$167,384	$171,091	$169,659

PIPELINE AND STORAGE THROUGHPUT – (MMCF)

Year Ended September 30	2002	2001	2000
Firm Transportation	**290,507**	304,183	291,818
Interruptible Transportation	**7,315**	17,372	21,730
	297,822	321,555	313,548

2002 Compared with 2001

Operating revenues for the Pipeline and Storage segment decreased $3.7 million in 2002 as compared with 2001. For 2002, the decrease resulted primarily from a $2.1 million decrease in transportation revenues, as shown in the table above, and a $1.6 million decrease in cashout revenues included in other revenues in the table above. Cashout revenues represent a cash resolution of a gas imbalance whereby a customer pays Supply Corporation for gas the customer receives in excess of amounts delivered into Supply Corporation's system by the customer's shipper. Cashout revenues are offset by purchased gas expense. The decrease in transportation revenues primarily reflects lower gathering rates (the rates charged by Supply Corporation to its transportation customers to move gas from a third-party well site or nearby meter to Supply Corporation's transmission pipelines for delivery) as a result of a provision in a February 1996 settlement with FERC that ended in 2001. However, this rate decrease is largely offset by a reduction in amortization expense, thus having little impact on net income. Another impact of this settlement was that Supply Corporation no longer had the responsibility to process gas for local producers. As such, there was a reduction in gas processing revenues. However, this reduction was offset by higher revenues from unbundled pipeline sales and open access transportation. Both gas processing revenues and revenues from unbundled pipeline sales and open access transportation are included in other revenues in the table above. While transportation volumes decreased during the year, volume fluctuations generally do not have a significant impact on revenues as a result of Supply Corporation's straight fixed-variable rate design.

2001 Compared with 2000

Operating revenues for the Pipeline and Storage segment increased $1.4 million in 2001 compared with 2000. The increase is attributable primarily to a $2.1 million increase in revenues from unbundled pipeline sales and open access transportation due to higher prices and volumes. While transportation volumes increased 8.0 Bcf during the fiscal year, volume fluctuations generally do not have a significant impact on revenues as a result of Supply Corporation's straight fixed-variable rate design.

Earnings

2002 Compared with 2001

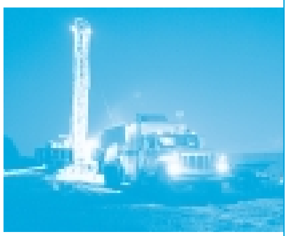
The Pipeline and Storage segment's earnings in 2002 were $29.7 million, a decrease of $10.7 million when compared with earnings of $40.4 million in 2001. However, as discussed above, the earnings for 2002 included a $9.9 million non-recurring after tax expense ($15.2 million pre tax) associated with the impairment of the Company's investment in the Independence Pipeline project. Earnings for 2001 included $4.2 million of non-recurring earnings associated with stock appreciation rights, $2.6 million of non-recurring earnings associated with a termination fee received from a customer to cancel a long-term transportation contract, and $1.1 million of non-recurring after tax expense associated with early retirement offers. Exclusive of these four items, there was an increase in earnings of $4.9 million. This increase resulted primarily from lower operation and maintenance expenses, which were the result of the Company's recent early retirement offers, and a lower effective income tax rate.

2001 Compared with 2000

The Pipeline and Storage segment's earnings for 2001 were $40.4 million, an increase of $8.8 million when compared with earnings for 2000. However, earnings for 2001 included $2.6 million of non-recurring earnings associated with a termination fee received from a customer to cancel a long-term transportation contract, and $1.1 million of non-recurring after tax expense associated with early retirement offers. Stock appreciation rights also had a significant impact on earnings as 2001 had earnings of $4.2 million and 2000 had $4.6 million of after tax expense. As previously discussed, significant swings in the market price of the Company's common stock caused this earnings impact. Exclusive of these four items, there was a decrease in earnings of $1.5 million. While revenues from unbundled pipeline sales and open access transportation increased, the increase was more than offset by additional executive retirement benefit expenses in 2001.

Exploration and Production

Revenues



EXPLORATION AND PRODUCTION OPERATING REVENUES

Year Ended September 30 (Thousands)	2002	2001	2000
Gas (after Hedging)	**$148,467**	$171,045	$108,832
Oil (after Hedging)	**152,746**	169,613	117,606
Gas Processing Plant	**16,995**	39,986	17,666
Other	**6,627**	17,700	(6,034)
Intrasegment Elimination[1]	**(13,855)**	(43,339)	(15,234)
	$310,980	$355,005	$222,836

(1) Represents the elimination of certain West Coast gas production revenue included in "Gas (after Hedging)" in the table above that is sold to the gas processing plant shown in the table above. An elimination for the same dollar amount is made to reduce the gas processing plant's purchased gas expense.

PRODUCTION VOLUMES

Year Ended September 30	2002	2001	2000
Gas Production *(MMcf)*			
Gulf Coast	**25,776**	30,663	32,760
West Coast	**4,889**	4,383	4,374
Appalachia	**4,402**	4,142	4,344
Canada	**6,387**	1,816	192
	41,454	41,004	41,670
Oil Production *(Mbbl)*			
Gulf Coast	**1,815**	1,914	1,415
West Coast	**3,004**	2,875	2,824
Appalachia	**9**	7	9
Canada	**2,834**	3,061	899
	7,662	7,857	5,147

AVERAGE PRICES

Year Ended September 30	2002	2001	2000
Average Gas Price/Mcf			
Gulf Coast	**$2.89**	$4.93	$3.29
West Coast	**$2.86**	$10.18	$3.62
Appalachia	**$3.74**	$5.03	$3.16
Canada	**$2.29**	$2.41	$2.52
Weighted Average	**$2.88**	$5.39	$3.31
Weighted Average After Hedging[1]	**$3.58**	$4.17	$2.61
Average Oil Price/barrel (bbl)			
Gulf Coast	**$22.83**	$27.47	$28.27
West Coast[2]	**$19.94**	$24.06	$23.87
Appalachia	**$23.76**	$28.51	$25.12
Canada	**$19.94**	$24.29	$29.28
Weighted Average	**$20.63**	$24.99	$26.03
Weighted Average After Hedging[1]	**$19.94**	$21.59	$22.85

(1) Refer to further discussion of hedging activities below under "Market Risk Sensitive Instruments" and in Note F – Financial Instruments in Item 8 of this report.
(2) Includes low gravity oil which generally sells for a lower price.

2002 Compared with 2001

Operating revenues for the Exploration and Production segment decreased $44.0 million in 2002 as compared with 2001. Oil production revenue after hedging decreased $16.9 million due primarily to a $1.65 per bbl decrease in the weighted average price of oil after hedging. Gas production revenue after hedging, decreased $22.6 million. Decreases in the weighted average price of gas after hedging ($0.59 per Mcf) more than offset an overall increase in gas production. The overall increase in gas production is largely attributable to the Canadian properties acquired in June 2001 (i.e., the Player Petroleum Corp. acquisition) (Player) offset partially by decreased production in the Gulf Coast region. The decrease in Gulf Coast production is the result of the previously announced strategy to exit the Gulf of Mexico and shift emphasis to longer-lived on-shore reserves. The Company is shifting its emphasis because it believes that future quality off-shore reserves will require deeper and riskier off-shore drilling that will be more expensive than the reserves it has been able to find under its current drilling program in the shallow waters of the Gulf of Mexico.* The Company anticipates that shifting to longer-lived on-shore reserves will allow it to drill and develop lower cost, lower risk reserves.* Gas processing plant revenues decreased $23.0 million due to significantly lower gas prices. Other revenues decreased $11.1 million largely due to the non-recurring mark-to-market gains on derivative financial instruments that were recorded in 2001, as discussed below.

Refer to further discussion of derivative financial instruments in the "Market Risk Sensitive Instruments" section that follows. Refer to the tables above for production and price information.

2001 Compared with 2000

Operating revenues for the Exploration and Production segment increased $132.2 million in 2001 compared with 2000. Gas production revenue after hedging increased $62.2 million due primarily to an increase in the weighted average price of gas after hedging. Overall gas production decreased, primarily in the Gulf Coast region, as there were delays in placing new platforms on production (due to rig availability constraints) and delays in work-over activity, mostly during the first and second quarters of 2001. New Gulf Coast production in the second half of 2001 was primarily oil production. Gas production from the Player acquisition in June 2001 helped mitigate the gas production decline in the Gulf Coast region. Oil production revenue after hedging increased $52.0 million in 2001 compared with 2000. This increase is due primarily to a 53% increase in oil production, largely attributable to the Exploration and Production segment's Canadian properties acquired as part of the June 2000 acquisition of Tri Link Resources, Ltd. (Tri Link). Revenue from this segment's gas processing plant was up $22.3 million due to higher prices. In addition, this segment recognized other revenue increases of $23.8 million due to mark-to-market adjustments related to derivative financial instruments. These mark-to-market adjustments largely related to written options that did not qualify for hedge accounting. The written options covered the period from January 1999 to December 2000.

Earnings

2002 Compared with 2001

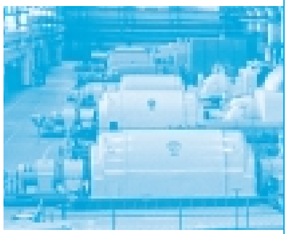
The Exploration and Production segment's earnings in 2002 were $26.9 million, an increase of $59.2 million when compared with a loss of $32.3 million in 2001. However, 2001 earnings included a non-cash impairment of this segment's oil and gas assets totaling $104.0 million after tax, as previously discussed. Excluding the impact of this impairment, there was a decrease in earnings of $44.8 million. As discussed above, decreases in the weighted average commodity prices of crude oil and natural gas after hedging ($1.65 per bbl and $0.59 per Mcf, respectively) were primarily responsible for this earnings decrease. Higher workover expenses in the Gulf Coast region also contributed to the earnings decrease. The major workover expenditures occurred on Vermilion 252 and Eugene Island Block 264.

2001 Compared with 2000

The Exploration and Production segment experienced a loss of $32.3 million in 2001, a decrease of $67.2 million when compared to 2000 earnings of $34.9 million. Excluding the $104.0 million after tax non-cash impairment discussed above, this segment had 2001 earnings of $71.8 million, an increase of $36.9 million from 2000 earnings. A 53% increase in oil production, largely attributable to the Tri Link acquisition in June 2000, combined with higher natural gas prices, were major factors in this segment's earnings increase, exclusive of the non-cash asset impairment. Also, this segment's earnings benefited from the mark-to-market revenue increases discussed above. Partly offsetting higher revenues was an increase in production related expenses, including higher depletion, higher purchased gas expense (for the gas processing plant), an increase in lease operating costs and higher production taxes. General and administrative expenses increased, largely due to the Player and Tri Link acquisitions. Greater interest expense due to higher borrowings related to the Player and Tri Link acquisitions also partially offset the positive impact of higher revenues.

International

Revenues



INTERNATIONAL OPERATING REVENUES

Year Ended September 30 (Thousands)	2002	2001	2000
Heating	$65,386	$69,072	$69,387
Electricity	26,960	26,398	31,426
Other	2,969	2,440	3,923
	$95,315	$97,910	$104,736

INTERNATIONAL HEATING AND ELECTRIC VOLUMES

Year Ended September 30	2002	2001	2000
Heating Sales (Gigajoules) (1)	8,689,887	9,978,118	10,222,024
Electricity Sales (megawatt hours)	972,832	1,019,901	1,147,303

(1) Gigajoules = one billion joules. A joule is a unit of energy.

2002 Compared with 2001

Operating revenues for the International segment decreased $2.6 million in 2002 as compared with 2001. The decrease in heat revenues in 2002 compared to 2001 reflects the June 2001 sale of Jablonecka teplarenska a realitni, a.s. (a district heating plant located in the Czech Republic which had heating revenues of $7.1 million in 2001, and heating volumes of 685,137 gigajoules in 2001). It also reflects the impact of weather in the Czech Republic, which was 5% warmer in 2002 than in the prior year. However, an increase in the average value of the Czech koruna (CZK) compared to the U.S. dollar offset much of the impact of these negative factors.

2001 Compared with 2000

Operating revenues for the International segment decreased $6.8 million in 2001 compared with 2000. The revenue decrease largely reflects a decrease in the average value of the CZK compared to the U.S. dollar during the 2001 heating season compared to the 2000 heating season. Exclusive of the exchange rate impact, heating revenues increased due to rate increases offset partly by lower volumes associated with warmer weather. Electric revenues, exclusive of the exchange rate impact, decreased as a result of lower volumes (principally attributable to the scheduled shutdown of a generating turbine that had reached the end of its useful life) and a decline in electric rates.

Earnings

2002 Compared with 2001

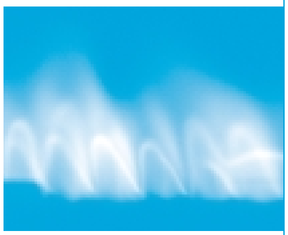
The International segment experienced a loss of $4.4 million in 2002 compared with a loss of $3.0 million in 2001. Higher operation and maintenance expenses associated with the Company's European power development projects (refer to Capital Resources and Liquidity under the heading "Estimated Capital Expenditures") were the main factors for the higher loss in 2002. Lower interest expense and a higher effective tax rate partially offset the impact of higher operation and maintenance expenses.

2001 Compared with 2000

The International segment experienced a loss of $3.0 million in 2001 compared with 2000 earnings of $3.3 million. Lower heat and electric margins, as a result of warmer weather and the scheduled shutdown of a generating turbine, were the primary reasons for this decrease. The decrease also reflects a decrease in value of the CZK compared to the U.S. dollar, as previously discussed.

Energy Marketing

Revenues



ENERGY MARKETING OPERATING REVENUES

Year Ended September 30 (Thousands)	2002	2001	2000
Natural Gas (after Hedging)	**$151,219**	$257,005	$139,614
Electricity	**—**	1,362	1,941
Other	**38**	839	(7,626)
	$151,257	$259,206	$133,929

ENERGY MARKETING VOLUMES

Year Ended September 30	2002	2001	2000
Natural Gas – (MMcf)	**33,042**	36,753	35,465

2002 Compared with 2001

Operating revenues for the Energy Marketing segment decreased $107.9 million in 2002, as compared with 2001. This decrease was primarily the result of lower natural gas commodity prices that were recovered through revenues. Lower volumes, which were principally the result of warmer weather, also contributed to the decrease in operating revenues.

Refer to further discussion of derivative financial instruments in the "Market Risk Sensitive Instruments" section that follows.

2001 Compared with 2000

Operating revenues for the Energy Marketing segment increased $125.3 million in 2001 compared with 2000. The primary reason for this increase was the higher gas costs that are reflected in the natural gas marketing revenues. Higher marketing volumes are primarily due to colder weather in 2001 compared to 2000. This compensated for a 4% decrease in NFR's customers from September 30, 2000 to September 30, 2001. In addition, the Energy Marketing segment recognized a negative $8.6 million mark-to-market adjustment in 2000 (included in "Other" on the table above) related to written options and futures contracts that did not qualify for hedge accounting.

Earnings

2002 Compared with 2001

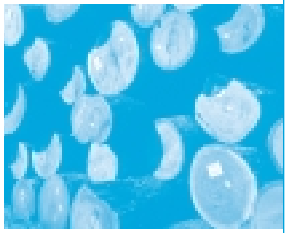
Earnings in the Energy Marketing segment increased $12.1 million in 2002 as compared with 2001. This increase primarily reflects higher margins on gas sales and lower interest and operation and maintenance expenses. Margins increased as a result of improved operational strategies put in place by the Energy Marketing segment's new management team.

2001 Compared with 2000

The Energy Marketing segment incurred a loss for 2001 of $3.4 million, a decrease of $4.4 million compared with the loss of $7.8 million in 2000. However, the loss for 2001 included $1.3 million of non-recurring after tax expense associated with a mark-to-market loss on natural gas inventory. Exclusive of this item, the loss in 2001 was $2.1 million, a decrease of $5.7 million from the loss incurred in 2000. The most significant reason for the lower loss was the change in mark-to-market adjustments from 2000 to 2001 ($5.9 million positive contribution after tax), referred to above.

Timber

Revenues



TIMBER OPERATING REVENUES

Year Ended September 30 (Thousands)	2002	2001	2000
Log Sales	$21,528	$23,460	$24,091
Green Lumber Sales	6,567	5,597	4,397
Kiln Dry Lumber Sales	15,976	12,320	10,152
Other	3,336	3,537	2,905
	$47,407	$44,914	$41,545

TIMBER BOARD FEET

Year Ended September 30 (Thousands)	2002	2001	2000
Log Sales	8,174	8,839	9,370
Green Lumber Sales	12,878	10,332	8,193
Kiln Dry Lumber Sales	10,794	8,804	6,987
	31,846	27,975	24,550

2002 Compared with 2001

Operating revenues for the Timber segment increased $2.5 million in 2002, as compared with 2001. When comparing 2002 to 2001, log sales decreased $1.9 million as weather that was warmer and wetter than normal during the first and second quarters of 2002 hampered the ability to cut and haul logs, specifically cherry veneer. The Company made up for this lost revenue through higher sales of lumber. Green lumber sales increased $1.0 million and kiln dry lumber sales increased $3.7 million (mostly due to an increase in kiln dry cherry volumes).

2001 Compared with 2000

Operating revenues for the Timber segment increased $3.4 million in 2001, as compared with 2000. Green lumber sales were up due to an increase in board feet sold at slightly higher prices. The increase in kiln dry lumber sales was due to the operation of two additional kilns brought on line in August 2000. The decrease in log sales revenues primarily reflects lower sales of quality logs offset partly by higher average prices.

Earnings

2002 Compared with 2001

Earnings in the Timber segment increased $2.0 million in 2002 as compared with 2001. The increase was primarily due to higher operating revenues, as mentioned above, and lower interest expense. The increase in operating revenues was primarily due to an increase in kiln dry cherry lumber sales volumes.

2001 Compared with 2000

Timber segment earnings of $7.7 million in 2001 were up $1.6 million compared with 2000. The increase was primarily due to higher operating revenues, as mentioned above, and lower interest expense.

Corporate and All Other Operations

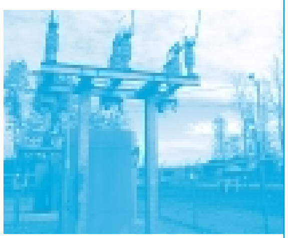
2002 Compared with 2001

Corporate and all other operations experienced a loss of $2.3 million in 2002, an improvement of $2.2 million over the loss of $4.5 million in 2001. However, the loss for 2001 included $0.7 million of non-recurring earnings associated with stock appreciation rights and $3.5 million of non-recurring after tax expense associated with a mark-to-market loss on natural gas inventory by Upstate, the Company's wholly-owned subsidiary which is engaged in wholesale natural gas marketing and other energy-related activities. Exclusive of these items, earnings decreased $0.6 million largely due to higher interest costs, partially offset by lower operation costs.

2001 Compared with 2000

Corporate and all other operations experienced a loss of $4.5 million in 2001, a decrease of $5.9 million over the gain of $1.4 million in 2000. However, the loss for 2001 included $3.5 million of non-recurring after tax expense associated with a mark-to-market loss on natural gas inventory by Upstate, as discussed above. Stock appreciation rights also had a significant impact on earnings as 2001 had earnings of $0.7 million and 2000 had $0.7 million of after tax expense. As previously discussed, significant swings in the market price of the Company's common stock caused this earnings impact. Exclusive of these three items, earnings decreased $3.8 million largely due to higher interest costs and higher operation costs.

Operations of Unconsolidated Subsidiaries



The Company's unconsolidated subsidiaries consist of equity method investments in Seneca Energy II, LLC (Seneca Energy), Model City Energy, LLC (Model City), and Energy Systems North East, LLC (ESNE). The Company has 50% ownership interests in each of these entities. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. ESNE generates electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. ESNE sells its electricity into the New York power grid. The Company also had a 33-1/3% equity method investment in Independence Pipeline Company which was written off in 2002, as previously discussed. The Independence write-off of $15.2 million ($9.9 million after tax) is recorded on the Consolidated Statement of Income as Impairment of Investment in Partnership.

2002 Compared with 2001

Income from unconsolidated subsidiaries (which represents the Company's equity method interest in the income or loss from its investment in unconsolidated subsidiaries) decreased $1.6 million in 2002 compared with 2001. This decrease is largely attributable to losses experienced by the ESNE investment during 2002 of $0.1 million compared to income in the prior year of $0.9 million. ESNE was formed on April 30, 2001 so income for 2001 did not reflect any of the normal operating losses that ESNE incurs during the fall and winter months. ESNE generates most of its electricity during the spring and summer months when electricity demand peaks for air conditioning requirements. ESNE experienced higher electric generation revenues in the spring and summer of 2001 compared with the same period in 2002. The Seneca Energy investment also experienced an earnings decrease of $0.6 million due to lower electric generation revenues and higher repair and maintenance expenditures on the generating engines. Some repairs were delayed from 2001 to 2002 to enable Seneca Energy to operate more hours while market prices for electricity were higher than normal.

2001 Compared with 2000

Income from unconsolidated subsidiaries increased $0.1 million in 2001 compared with 2000. The ESNE and Model City investments added income of $0.9 million and $0.1 million, respectively, as 2001 was the first year of operation for both investments. The Seneca Energy investment also saw an increase in income of $0.5 million as 2001 was the first complete year of operation for this investment. These increases were largely offset by a $1.4 million reduction in equity method income from Independence Pipeline Company.

Other Income and Interest Charges

Although most of the variances in Other Income items and Interest Charges are discussed in the earnings discussion by segment above, following is a summary on a consolidated basis:

Other Income

Other income decreased $3.6 million in 2002 compared with 2001. This decrease resulted primarily from a $4.0 million termination fee received in 2001 from a customer in the Pipeline and Storage segment to cancel a long-term transportation contract. The Company has been able to market the excess capacity resulting from this termination.

Other income increased $4.8 million in 2001 compared with 2000. This increase resulted primarily from the same $4.0 million buyout of a long-term transportation contract in the Pipeline and Storage segment discussed above.

Interest Charges

Interest on long-term debt increased $8.7 million in 2002 and $14.7 million in 2001. The increase in both years resulted mainly from a higher average amount of long-term debt outstanding. Long-term debt balances have grown significantly over the past few years primarily as a result of acquisition activity in the Exploration and Production segment. These acquisitions were initially financed with short-term debt which was subsequently repaid through the proceeds from the issuance of long-term debt.

Other interest charges decreased $10.2 million in 2002 and $7.6 million in 2001. The decrease in 2002 was the result of a decrease in the average amount of short-term debt outstanding (short-term debt was refinanced with long-term debt) and lower weighted average interest rates. The decrease in 2001 was primarily the result of lower weighted average interest rates on short-term debt.

Capital Resources and Liquidity

The primary sources and uses of cash during the last three years are summarized in the following condensed statement of cash flows:

SOURCES (USES) OF CASH

Year Ended September 30 (Millions)	2002	2001	2000
Provided by Operating Activities	**$345.6**	$414.0	$238.2
Capital Expenditures	**(232.4)**	(292.7)	(269.4)
Investment in Subsidiaries, Net of Cash Acquired	**—**	(90.6)	(123.8)
Investment in Partnerships	**(0.5)**	(1.8)	(4.4)
Other Investing Activities	**27.1**	(2.8)	13.3
Short-Term Debt, Net Change	**(224.8)**	(143.4)	226.5
Long-Term Debt, Net Change	**139.6**	187.2	(18.1)
Issuance of Common Stock	**10.9**	11.5	14.3
Dividends Paid on Common Stock	**(81.0)**	(76.7)	(73.0)
Dividends Paid to Minority Interest	**—**	—	(0.2)
Effect of Exchange Rates on Cash	**1.5**	(0.6)	(0.5)
Net Increase (Decrease) in Cash and Temporary Cash Investments	**$(14.0)**	$4.1	$2.9

Operating Cash Flow

Internally generated cash from operating activities consists of net income available for common stock, adjusted for noncash expenses, noncash income and changes in operating assets and liabilities. Noncash items include depreciation, depletion and amortization, impairment of oil and gas producing properties (in 2001), deferred income taxes, impairment of investment in partnership, income or loss from unconsolidated subsidiaries net of cash distributions and minority interest in foreign subsidiaries.

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from year to year because of the impact of rate cases. In the Utility segment, supplier refunds, over- or under-recovered purchased gas costs and weather also significantly impact cash flow. The impact of weather on cash flow is tempered in the Utility segment's New York rate jurisdiction by its WNC and in the Pipeline and Storage segment by Supply Corporation's straight fixed-variable rate design.

Cash provided by operating activities in the Exploration and Production segment may vary from period to period as a result of changes in the commodity prices of natural gas and crude oil. The Company uses various derivative financial instruments, including price swap agreements, no cost collars and options in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $345.6 million in 2002, a decrease of $68.4 million compared with the $414.0 million provided by operating activities in 2001. Lower cash receipts from the sale of oil and gas in the Exploration and Production segment more than offset higher margins on gas sales in the Energy Marketing segment. Oil and gas prices were down significantly in the Exploration and Production segment for much of 2002 and oil and gas production was slightly lower than 2001.

Investing Cash Flow

Expenditures for Long-Lived Assets

Expenditures for long-lived assets include additions to property, plant and equipment (capital expenditures) and investments in corporations (stock acquisitions) or partnerships, net of any cash acquired.

The Company's expenditures for long-lived assets totaled $232.9 million in 2002. The table below presents these expenditures:

Year Ended September 30, 2002 (Millions)	Capital Expenditures	Investments in Corporations or Partnerships	Total Expenditures For Long-Lived Assets
Utility	$51.5	$ —	$51.5
Pipeline and Storage	29.8	0.5	30.3
Exploration and Production	114.6	—	114.6
International	4.2	—	4.2
Energy Marketing	0.1	—	0.1
Timber	25.6	—	25.6
All Other	6.6	—	6.6
	$232.4	$0.5	$232.9

Utility

The majority of the Utility capital expenditures were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The majority of the Pipeline and Storage segment's capital expenditures were made for additions, improvements and replacements to this segment's transmission and gas storage systems. Approximately $4.4 million was spent on expansion of transportation capacity on Line YM53 running from Ellisburg, Pennsylvania to Leidy, Pennsylvania.

During 2002, SIP made an additional $536,000 investment in Independence Pipeline Company (Independence), bringing SIP's total investment to $15.2 million. In June 2002, Independence submitted a motion to FERC requesting that FERC vacate the certificate issued to Independence on July 12, 2000 to construct, own and operate the Independence Pipeline. Independence took this action because it had been unable to obtain sufficient customer contracts to proceed with the project. In connection with the filing of the motion by Independence, SIP wrote off its $15.2 million investment in Independence, as previously discussed. FERC formally vacated the certificate in an order issued in July 2002.

Exploration and Production

The Exploration and Production segment's capital expenditures included approximately $81.5 million of capital expenditures for on-shore drilling, construction and recompletion costs for wells located in Louisiana, Texas, California and Canada as well as on-shore geological and geophysical costs, including the purchase of certain three-dimensional seismic data and fixed asset purchases. Of the $81.5 million discussed above, $27.0 million was spent on the Exploration and Production segment's Canadian properties. The Exploration and Production segment's capital expenditures also included approximately $33.1 million for its off-shore program in the Gulf of Mexico, including offshore drilling expenditures, offshore construction, lease acquisition costs and geological and geophysical expenditures.

During 2002, the Exploration and Production segment sold oil and gas properties amounting to $22.1 million. Most of these properties were in the Gulf Coast region. These proceeds were recorded as a reduction of property, plant and equipment and are reflected in Other Investing Activities on the Consolidated Statement of Cash Flows.

International

The majority of the International segment's capital expenditures were concentrated on the construction of boilers at a district heating and power generation plant in the Czech Republic. The expenditures also included improvements and replacements within the district heating and power generation plants.

Timber

The majority of the Timber segment capital expenditures were made for the purchase of land and timber rights in Potter County, Pennsylvania in June 2002. The land, consisting of approximately 3,656 acres, was purchased by Seneca from Wending Creek 3656, LLC, an entity controlled by certain members of the John Rigas family for $464,930. A Form 8-K filed by Adelphia Communications Corporation (Adelphia) on June 14, 2002 states that the Rigas family had previously agreed to transfer the land to Adelphia in exchange for a $464,930 reduction in the amount of the Rigas family's primary co-borrowing obligations, and Seneca paid the purchase price of the land directly to Adelphia. Highland purchased the timber rights associated with the land from ACC Operations, Inc., a wholly owned subsidiary of Adelphia, for $19,535,070. The remaining capital expenditures were for smaller purchases of land and timber as well as equipment for this segment's sawmill and kiln operations.

Estimated Capital Expenditures

The Company's estimated capital expenditures for the next three years are:*

Year Ended September 30 (Millions)	2003	2004	2005
Utility	$48.1	$48.1	$48.1
Pipeline and Storage	24.0	30.2	24.8
Exploration and Production	81.6	82.4	83.6
International	9.6	4.3	4.7
Timber	0.8	0.3	0.3
All Other	10.5	—	—
	$174.6	$165.3	$161.5

Estimated capital expenditures for the Utility segment in 2003 will be concentrated in the areas of main and service line improvements and replacements and, to a minor extent, the installation of new services.*

Estimated capital expenditures for the Pipeline and Storage segment in 2003 will be concentrated in the reconditioning of storage wells and the replacement of storage and transmission lines.* The estimated capital expenditures also include $5.0 million for an expansion of transportation capacity on Line YM53 running from Ellisburg, Pennsylvania to Leidy, Pennsylvania.* The estimated capital expenditures do not include any partnership investments for Northwinds Pipeline.

The estimated capital expenditures also do not include the Empire State Pipeline (Empire), which the Company agreed to purchase in October 2002 from Duke Energy Corporation for $180.0 million in cash plus assumed debt of $60.0 million or any subsequent capital expenditures that would occur upon completion of the acquisition. Empire is a 157-mile, 24-inch pipeline that begins at the Canadian border near Buffalo, New York, which is within the Company's service territory, and terminates in Central New York just north of Syracuse, New York. Empire is regulated by the NYPSC. Empire has the capacity to transport 525 million cubic feet of gas per day and currently has almost all of its capacity under contract, with a substantial portion being long-term contracts. Empire delivers natural gas supplies to major industrial companies, utilities (including the Company's Utility segment), and power producers. Empire would better position the Company to bring Canadian gas supplies into the East Coast markets of the United States as demand for natural gas along the East Coast increases.* The Company notified the Department of Justice and Federal Trade Commission of the proposed acquisition as required under the antitrust laws, and the Company's request for early termination of the antitrust waiting period has been granted. The Company has also made a filing seeking approval of the transaction from the NYPSC. Subject to NYPSC approval, it is anticipated that the purchase will be completed in the beginning of calendar 2003. * The Company is evaluating various alternatives to finance this acquisition. Those alternatives could include the sale of certain non-regulated assets, the issuance of equity, or the issuance of debt.*

The Company continues to explore various opportunities to participate in transporting gas to the Northeast, either through Supply Corporation's system or in partnership with others. This includes the proposed Northwinds Pipeline that the Company and TransCanada PipeLines Limited are pursuing. This project presently contemplates a 215-mile, 30-inch natural gas pipeline that would originate in Kirkwall, Ontario, cross into the United States near Buffalo, New York and follow a southerly route to its destination in the Ellisburg-Leidy area in Pennsylvania. At September 30, 2002, the Company had incurred approximately $1.3 million in costs (all of which have been expensed) associated with this project. The initial capacity of the pipeline would be approximately 500 million cubic feet of natural gas per day with the estimated cost of the pipeline ranging from $350 to $400 million. If the pipeline is constructed, it is possible that a significant amount of the construction costs would be financed by banks or other financial institutions with the pipeline serving as collateral for the financing arrangement.*

Estimated capital expenditures in 2003 for the Exploration and Production segment include approximately $37.6 million for Canada, $22.0 million for the Gulf Coast region ($15.4 million on the off-shore program in the Gulf of Mexico), $12.8 million for the West Coast region and $9.2 million for the Appalachian region.* Overall, estimated capital expenditures in 2003 for the Exploration and Production segment are lower than the prior year as the Company intends to live within cash flow and pay down debt.* It should also be noted that estimated off-shore expenditures are lower than the prior year as the Company continues to shift its emphasis from short-lived off-shore reserves to longer-lived on-shore reserves.

The estimated capital expenditures for the International segment in 2003 will be concentrated on improvements and replacements within the district heating and power generation plants in the Czech Republic.* The estimated capital expenditures do not include any expenditures for the Company's European power development projects. Currently, any costs incurred on these power development projects are expensed. The Company's European power development projects are primarily in Italy and Bulgaria. In Italy, the Company has signed a joint development agreement with an Italian utility for the construction of a 400-megawatt combined-cycle natural gas electric generating plant. The estimated cost of this project is $200.0 million to $210.0 million. In Bulgaria, the Company is pursuing the opportunity to construct, own and operate two new 127-megawatt gas-fired combustion turbines. The estimated cost of this project is $180.0 million to $200.0 million. Whether the Company moves forward to construct these projects will depend on successful negotiation of various operating agreements as well as the availability of funds from banks or other financial institutions to cover a significant amount of the construction costs.* The respective projects would serve as collateral for such financing arrangements.*

Estimated capital expenditures in the Timber segment will be concentrated on the purchase of land and timber as well as the construction or purchase of new facilities and equipment for this segment's sawmill and kiln operations.*

The estimated capital expenditures in the All Other category in 2003 will be concentrated on the purchase and installation of a gas turbine and steam turbine by Horizon Power to create a 55-megawatt cogeneration facility in Buffalo, New York.

The Company continuously evaluates capital expenditures and investments in corporations and partnerships. The amounts are subject to modification for opportunities such as the acquisition of attractive oil and gas properties, timber or storage facilities and the expansion of transmission line capacities. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company's other business segments depends, to a large degree, upon market conditions.*

Financing Cash Flow

In August 2002, $97.7 million of the Company's $100.0 million 6.214% medium-term notes due August 2027 were repaid by the Company at par plus accrued interest. The Company used short-term debt to temporarily refund the $97.7 million to the debt holders. The remaining $2.3 million of the original $100.0 million issuance is scheduled to mature in August 2027.

In September 2002, the Company issued $97.7 million of 6.5% senior unsecured notes due in September 2022. These notes become callable by the Company at par in September 2006. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $94.9 million. The proceeds of this debt issuance were used to repay the short-term debt used to temporarily refund the $97.7 million discussed in the previous paragraph.

In November 2001, the Company issued $150.0 million of 6.70% medium-term notes due in November 2011. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $149.0 million. The proceeds of this debt issuance were used to reduce short-term debt.

Consolidated short-term debt decreased $224.3 million during 2002 primarily due to the November 2001 medium-term note issuance discussed above, and the use of cash from operations to pay down short-term debt. The Company continues to consider short-term debt an important source of cash for temporarily financing capital expenditures and investments in corporations or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, exploration and development expenditures and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt issuance and repayment. The Company has SEC authorization under the Public Utility Holding Company Act of 1935, to borrow and have outstanding as much as $750.0 million of short-term debt at any time through December 31, 2005. The total amount available to be issued under the Company's commercial paper program is $200.0 million. The commercial paper program is backed by a committed $220 million, 364-day and 3-year credit facility which was effective on September 30, 2002. Under this committed credit facility, the Company agrees that its debt to capitalization ratio will not, at the last day of any fiscal quarter, exceed .65 from September 30, 2002 through September 30, 2003, .625 from October 1, 2003 through September 30, 2004 and .60 from October 1, 2004 and at all times thereafter. With regards to the Company's short-term notes payable to banks, the Company uses uncommitted bank lines of credit aggregating $415.0 million. These uncommitted bank lines of credit are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed.* If a downgrade in the Company's credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company could borrow under its uncommitted bank lines of credit or seek other liquidity sources, including cash provided by operations. At September 30, 2002, the Company had outstanding short-term notes payable to banks and commercial paper of $91.3 million and $174.1 million, respectively.

The Company's present liquidity position is believed to be adequate to satisfy known demands.* Under the Company's existing indenture covenants, at September 30, 2002, the Company would have been permitted to issue up to a maximum of $179.0 million in additional long-term unsecured indebtedness at projected market interest rates in addition to being able to issue new indebtedness to replace maturing debt.

The Company's indenture also contains certain cross-default provisions wherein the failure by the Company to pay the scheduled interest or principal on its outstanding short-term or long-term debt (if such failure is not cured) could trigger the obligation to re-pay the debt outstanding under said indenture. The Company believes that it has adequate committed credit facilities in place to protect against such defaults.*

The Company's embedded cost of long-term debt was 7.0% at both September 30, 2002 and 2001, respectively.

The Company also has authorization from the SEC, under the Holding Company Act, to issue long-term debt securities and equity securities in amounts not exceeding $1.5 billion at any one time outstanding during the order's authorization period, which extends to December 31, 2005. The Company currently has $27.3 million of securities registered under the Securities Act of 1933. Any additional public offerings above the $27.3 million would require the filing of a registration statement with the SEC.

The amounts and timing of the issuance and sale of debt or equity securities will depend on market conditions, indenture requirements, regulatory authorizations, and the capital requirements of the Company.

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating and capital leases. The Company's consolidated subsidiaries have operating leases, the majority of which are with the Utility and the Pipeline and Storage segments, having a remaining lease commitment of approximately $31.6 million. These leases have been entered into for the use of vehicles, construction tools, meters, computer equipment and other items and are accounted for as operating leases. The Company's minority owned entities, which are accounted for under the equity method, have capital leases of electric generating equipment having a remaining lease commitment of approximately $9.8 million. The Company has guaranteed 50% or $4.9 million of these capital lease commitments.

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2002, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
(Millions)	2003	2004	2005	2006	2007	Thereafter	Total
Long-Term Debt	$160.6	$235.6	$6.2	$4.4	$ —	$899.1	$1,305.9
Short-Term Bank Notes	91.3	—	—	—	—	—	91.3
Commercial Paper	174.1	—	—	—	—	—	174.1
Operating Lease Commitments	8.2	6.4	5.0	3.5	2.7	5.8	31.6
Capital Lease Commitments	0.6	0.6	0.7	0.7	0.7	1.6	4.9

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the consolidated balance sheet in accordance with SFAS 133 (see Item 7, MD&A under the heading "Critical Accounting Policies - Accounting for Derivative Financial Instruments"); (ii) Utility segment obligations to purchase gas to be resold in its regulated business in accordance with established regulatory mechanisms to pass through the cost of that gas to its retail customers; (iii) NFR or Upstate obligations to purchase gas or to purchase gas transportation/storage services where the amounts due on those obligations each month are included on the consolidated balance sheet as a current liability; and (iv) other obligations which are reflected on the consolidated balance sheet. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them on the table above.*

The Company is involved in litigation arising in the normal course of business. Also in the normal course of business, the Company is involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While the resolution of such litigation or regulatory matters could have a material effect on earnings and cash flows in the period of resolution, none of this litigation, and none of these regulatory matters, are expected to change materially the Company's present liquidity position, nor have a material adverse effect on the financial condition of the Company.*

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) that covers substantially all domestic employees of the Company. The Company has been making contributions to the Retirement Plan over the last several years equal to the maximum funding requirements of applicable laws and regulations. In light of the dramatic decline in the stock market over the last several months, the Company anticipates that it will continue making maximum funding contributions to the Retirement Plan.* During 2002, the Company contributed $15.4 million to the Retirement Plan. The Company anticipates annual contributions to the Retirement Plan will be in the range of $20.0 to $30.0 million for 2003 - 2005.* The Company expects that all subsidiaries having domestic employees covered by the Retirement Plan will make contributions to the Retirement Plan.* The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments, through short-term borrowings or through cash from operations.*

Market Risk Sensitive Instruments

Energy Commodity Price Risk

The Company, primarily in its Exploration and Production and Energy Marketing segments, uses various derivative financial instruments (derivatives), including price swap agreements, no cost collars, options and futures contracts, as part of the Company's overall energy commodity price risk management strategy. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from or pay to the respective counterparties at September 30, 2002 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas and crude oil transactions that are related to the financial instruments.

The following tables disclose natural gas and crude oil price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in "Inside FERC" or on the New York Mercantile Exchange. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2002. At September 30, 2002, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2004.

NATURAL GAS PRICE SWAP AGREEMENTS

	Expected Maturity Dates		
	2003	2004	Total
Notional Quantities (Equivalent Bcf)	12.3	6.2	18.5
Weighted Average Fixed Rate (per Mcf)	$3.81	$3.59	$3.73
Weighted Average Variable Rate (per Mcf)	$4.30	$4.20	$4.27

CRUDE OIL PRICE SWAP AGREEMENTS

	Expected Maturity Dates
	2003
Notional Quantities (Equivalent bbls)	3,252,000
Weighted Average Fixed Rate (per bbl)	$21.28
Weighted Average Variable Rate (per bbl)	$27.92

At September 30, 2002, the Company would have had to pay the respective counterparties an aggregate of approximately $9.3 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have had to pay an aggregate of approximately $19.7 million to the counterparties to terminate the crude oil price swap agreements outstanding at September 30, 2002.

At September 30, 2001, the Company had natural gas price swap agreements covering 27.5 Bcf at a weighted average fixed rate of $3.77 per Mcf. The Company also had crude oil price swap agreements covering 6,643,980 bbls at a weighted average fixed rate of $22.15 per bbl. As indicated in the tables above, the Company has significantly reduced its use of natural gas and crude oil price swap agreements, which is primarily attributable to low commodity prices during much of 2002, which prevented the Company from locking in favorable prices for its oil and gas production. As commodity prices have improved in the first quarter of 2003, the Company may increase its use of natural gas and crude oil price swap agreements.*

The following tables disclose the notional quantities, the weighted average ceiling price and the weighted average floor price for the no cost collars used by the Company to manage natural gas and crude oil price risk. The no cost collars provide for the Company to receive monthly payments from (or make payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). At September 30, 2002, the Company had not entered into any natural gas or crude oil no cost collars extending beyond 2004.

NO COST COLLARS

	Expected Maturity Dates		
	2003	2004	Total
Natural Gas			
Notional Quantities (Equivalent Bcf)	8.6	0.2	8.8
Weighted Average Ceiling Price (per Mcf)	$5.74	$4.40	$5.71
Weighted Average Floor Price (per Mcf)	$3.80	$3.71	$3.80
Crude Oil			
Notional Quantities (Equivalent bbls)	1,125,000	270,000	1,395,000
Weighted Average Ceiling Price (per bbl)	$26.41	$25.80	$26.29
Weighted Average Floor Price (per bbl)	$21.96	$22.00	$21.97

At September 30, 2002, the Company would have received from the respective counterparties an aggregate of approximately $1.7 million to terminate the natural gas no cost collars outstanding at that date. The Company would have paid an aggregate of approximately $2.4 million to terminate the crude oil no cost collars outstanding at that date.

At September 30, 2001, the Company had natural gas no cost collars covering 9.2 Bcf at a weighted average floor price of $4.06 per Mcf and a weighted average ceiling price of $5.36 per Mcf. The Company also had crude oil no cost collars covering 2,730,000 bbls at a weighted average floor price of $21.94 per bbl and a weighted average ceiling price of $27.25 per bbl. As discussed above, low commodity prices during much of 2002 were the primary factors for the decrease in no cost collars from September 2001 to September 2002. With improvements in commodity prices during the first quarter of 2003, the Company may increase its use of natural gas and crude oil no cost collars.*

The following table discloses the notional quantities and weighted average strike prices by expected maturity dates for options used by the Company to manage natural gas price risk. The put options provide for the Exploration and Production segment of the Company to receive monthly payments from other parties when a variable price falls below an established floor or "strike" price. The call options provide for the Energy Marketing segment of the Company to receive monthly payments from other parties when a variable price rises above an established ceiling or "strike" price. At September 30, 2002, the Company held no options with maturity dates extending beyond 2003.

OPTIONS PURCHASED

	Expected Maturity Date 2003
Natural Gas Put Options	
Notional Quantities (Equivalent Bcf)	0.2
Weighted Average Strike Price (per Mcf)	$3.98
Natural Gas Call Options	
Notional Quantities (Equivalent Bcf)	0.2
Weighted Average Strike Price (per Mcf)	$4.73

At September 30, 2002, the Company would have received from the respective counterparties an aggregate of approximately $0.1 million to terminate the put options outstanding at that date. The Company would have received an aggregate of approximately $0.1 million to terminate the call options outstanding at that date.

At September 30, 2001, the Exploration and Production segment of the Company had natural gas put options covering 2.7 Bcf at a weighted average strike price of $4.11 per Mcf. The Company did not have any call options outstanding at that date. Because of the low commodity prices during much of 2002, the Company did not enter into any new put options during 2002. As for the call options, the Energy Marketing segment of the Company began purchasing call options in 2002 as it began to offer variable price deals with a price cap to its residential customers.

The following table discloses the net notional quantities, weighted average contract prices and weighted average settlement prices by expected maturity date for futures contracts used to manage natural gas price risk. At September 30, 2002, the Company held no futures contracts with maturity dates extending beyond 2004.

FUTURES CONTRACTS

	Expected Maturity Dates		
	2003	2004	Total
Net Contract Volumes Purchased (Equivalent Bcf)	3.1	0.3	3.4
Weighted Average Contract Price (per Mcf)	$3.70	$2.79	$3.67
Weighted Average Settlement Price (per Mcf)	$4.50	$4.44	$4.49

At September 30, 2002, the Company would have received $2.1 million to terminate these futures contracts.

At September 30, 2001, the Company had futures contracts covering 13.2 Bcf (net long position) at a weighted average contract price of $4.17 per Mcf. As indicated in the table above, the Company has significantly reduced its use of natural gas futures contracts. This reduction can be attributed primarily to a reduction in fixed price gas sales commitments in the Energy Marketing segment. At September 30, 2001, natural gas prices were low and many of the customers in the Energy Marketing segment entered into fixed price contracts to lock in the commodity price of natural gas at that time. At September 30, 2002, with natural gas prices being much higher than the prior year, many of the customers in the Energy Marketing segment chose to enter into variable price contracts that provided the opportunity to enter into a fixed price contract at a later date. With variable price contracts, commodity price risk is moved from the Company to the customer.

The Company may be exposed to credit risk on some of the derivatives disclosed above. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check and then, on an ongoing basis, monitors counterparty credit exposure. Management has obtained guarantees from the parent companies of the respective counterparties to its derivative financial instruments. At September 30, 2001, the Company used five counterparties for its over the counter derivative financial instruments. To further reduce credit risk, the Company increased the number of its counterparties to seven at September 30, 2002. At September 30, 2002, no individual counterparty represented greater than 25% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company's total volumes hedged).

Exchange Rate Risk

The International segment's investment in the Czech Republic is valued in Czech korunas, and, as such, this investment is subject to currency exchange risk when the Czech korunas are translated into U.S. dollars. The Exploration and Production segment's investment in Canada is valued in Canadian dollars, and, as such, this investment is subject to currency exchange risk when the Canadian dollars are translated into U.S. dollars. At September 30, 2002 compared to September 30, 2001, the Czech koruna was higher in value in relation to the U.S. dollar, resulting in a $24.1 million positive adjustment to the Cumulative Foreign Currency Translation Adjustment (CTA) (a component of Accumulated Other Comprehensive Income/Loss). At September 30, 2002 compared to September 30, 2001, the Canadian dollar was slightly higher in value in relation to the U.S. dollar, resulting in a $0.2 million positive adjustment to the CTA. Further valuation changes to the Czech koruna and Canadian dollar would result in corresponding positive or negative adjustments to the CTA. Management cannot predict whether the Czech koruna or Canadian dollar will increase or decrease in value against the U.S. dollar.*

Interest Rate Risk

The Company's exposure to interest rate risk arises primarily from its borrowing under short-term debt instruments. At September 30, 2002, these instruments included domestic short-term bank loans and commercial paper totaling $254.0 million. The interest rate on these short-term bank loans and commercial paper approximated 2.0% at September 30, 2002. The Company's short-term debt instruments also included $11.4 million of short-term bank loans in Canada and the Czech Republic at September 30, 2002. The weighted average interest rates on the Canadian and Czech Republic loans approximated 3.7% and 3.3%, respectively, at September 30, 2002.

The following table presents the principal cash repayments and related weighted average interest rates by expected maturity date for the Company's long-term fixed rate debt as well as the other long-term debt of certain of the Company's subsidiaries. The interest rates for the variable rate debt are based on those in effect at September 30, 2002:

	Principal Amounts by Expected Maturity Dates						
(Millions of Dollars)	2003	2004	2005	2006	2007	Thereafter	Total
National Fuel Gas Company							
Long-Term Fixed Rate Debt	$150	$225	$ —	$ —	$ —	$899	$1,274
Weighted Average Interest Rate Paid	7.3%	7.3%	—%	—%	—%	6.9%	7.0%
Fair Value = $1,362.0 million							
Other Notes							
Long-Term Debt (1)	$10.6	$10.6	$6.2	$4.4	$ —	$0.1	$31.9
Weighted Average Interest Rate Paid	5.1%	5.1%	5.6%	6.1%	—%	3.1%	5.3%
Fair Value = $31.9 million							

(1) $15.6 million is variable rate debt; $16.3 million is fixed rate debt.

Rate Matters

Utility Operation

Base rate adjustments in both the New York and Pennsylvania jurisdictions do not reflect the recovery of purchased gas costs. Such costs are recovered through operation of the purchased gas adjustment clauses of the appropriate regulatory authorities.

New York Jurisdiction

On October 11, 2000, the NYPSC approved a settlement agreement (Agreement) between Distribution Corporation, Staff of the Department of Public Service, the New York State Consumer Protection Board and Multiple Intervenors (an advocate for large commercial and industrial customers) that establishes rates for a three-year period beginning October 1, 2000. The Agreement provided that customers receive a bill credit of $17.6 million for the November 1, 2000 through March 31, 2001 heating season, of which $7.6 million related to customers' share of earnings accumulated under previous settlements. The credit was reduced to $5.0 million for the November 1, 2001 through March 31, 2002 heating season. The credit will remain at $5.0 million for the November 1, 2002 through March 31, 2003 heating season and subsequent heating seasons unless the Company can demonstrate that it is no longer justified. Also, earnings beyond a target level of 11.5% return on equity will be shared equally between shareholders and customers. The Agreement provides further that the Company and interested parties will resume discussions to address the NYPSC's competition initiatives, including changes to "customer choice" transportation services, among other things. Those discussions commenced in November 2000 and ultimately produced an interim "Joint Proposal," or settlement agreement, addressing several discrete issues of interest to the parties and the NYPSC. In an order issued on May 30, 2001, the NYPSC adopted the parties' Joint Proposal. As recommended by the parties, the Joint Proposal modifies Distribution Corporation's operations relating to transportation services and transactions with marketers and producers of indigenous natural gas. Under the Joint Proposal, the parties also agreed to continue negotiations to implement additional features of the NYPSC's restructuring initiative (described below). Those confidential discussions, dubbed "Phase III negotiations," concluded on January 18, 2002 when the parties executed a "Comprehensive Joint Proposal". The Comprehensive Joint Proposal proposes a number of changes to Distribution Corporation's rates and services through September 30, 2003, including the following:

- Modification of transportation balancing services and upstream capacity rules for the benefit of marketers and to preserve reliability;
- A customer funded "back-out credit" provided to marketers (or marketer customers) to reduce marketer costs and thereby promote competition;
- Provisions to promote increased marketer usage of indigenous natural gas;
- An expanded low-income program that provides arrearage forgiveness and a discounted rate for up to 30,000 customers;
- Increased customer funding to offset the cost of uncollectibles;
- Unbundling of gas costs from delivery rates; and
- Mechanisms for recovery of stranded pipeline and unbundling costs.

The Comprehensive Joint Proposal was filed with the NYPSC on January 23, 2002 and approved with immaterial modifications on April 18, 2002, effective May 1, 2002. Distribution Corporation's base rates will not be materially changed under the Comprehensive Joint Proposal, which is not intended to modify the rate and revenue requirements established in the Agreement described above.

On September 20, 2001, the NYPSC issued an order under which Distribution Corporation was Ordered to Show Cause why an action for penalties up to $19 million should not be commenced against it for alleged violations of consumer protection requirements. According to the NYPSC, the alleged violations may have caused or contributed to the death of an individual in an unheated apartment. On December 3, 2001, Distribution Corporation filed its response (submitted under a seal of confidentiality imposed by the Supreme Court, Erie County designed to protect the personal privacy interests of the deceased individual) and requested that the NYPSC either close (dismiss) the Show Cause proceeding based on the evidence presented in Distribution's response, or hold administrative evidentiary hearings "to demonstrate that a penalty action is unwarranted." On July 25, 2002 the NYPSC issued an order granting Distribution Corporation's request for hearings, and referred the matter to an administrative law judge for scheduling. The Company believes and will continue to vigorously assert that the NYPSC's allegations lack merit.

Pennsylvania Jurisdiction

Distribution Corporation currently does not have a rate case on file with the Pennsylvania Public Utility Commission (PaPUC). Management will continue to monitor its financial position in the Pennsylvania jurisdiction to determine the necessity of filing a rate case in the future.

Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. Management will continue to monitor Supply Corporation's financial position to determine the necessity of filing a rate case in the future.

The federal law under which FERC regulates Supply Corporation's rates, practices, and terms and conditions of service requires, among other things, that Supply Corporation not grant any undue preference or advantage to any person. In March 2001, FERC staff began a routine audit of Supply Corporation's practices and dealings with "marketing affiliates," i.e., other Company subsidiaries which conduct natural gas transportation and/or storage transactions with Supply. On July 11, 2002, FERC adopted an order instituting an investigation directed to Supply Corporation and its natural gas marketing affiliates, under Sections 4 and 5 of the Natural Gas Act and Section 501 of the Natural Gas Policy Act. This is not an investigation into Supply's currently effective rates, or any energy trading activities, "wash sales," "round-trip transactions," sales of electricity into the California market, or other activities that have been the subjects of recent news stories regarding other publicly traded energy companies. The Company does not engage in any such energy trading activities. The stated basis for instituting the investigation is information received during the audit which indicates there may have been violations of FERC regulations, specifically:

18 CFR Section 161.3(f), which requires that, to the extent Supply Corporation provides to a gas marketing affiliate information related to gas transportation, Supply Corporation must provide that information contemporaneously to all potential shippers [FERC staff has indicated that they believe Supply Corporation violated this regulation by e-mailing information describing daily operationally available capacity on its gas transportation system to a large number of shippers (including one Supply Corporation marketing affiliate) a few hours before that information was posted on Supply Corporation's website later that same day; Supply Corporation now provides such e-mails after the information is posted on its website]; and

18 CFR Section 161.3(l), which requires that Supply Corporation must timely post on its website lists of gas marketing affiliates, organizational charts and job descriptions of various individuals (Supply Corporation has updated this information).

Supply Corporation and its affiliates continue to cooperate with FERC staff by providing responses to multiple document requests in connection with this investigation and the preceding audit, and by making individuals available for interviews. The Company believes, based on the information presently known, that neither Supply Corporation nor any affiliate has received any benefit from any violations of FERC regulations which may have occurred, and that the ultimate resolution of this proceeding will not materially affect the Company's operations or financial condition.

Other Matters

Environmental Matters

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. The Company has estimated its clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $5.1 million to $6.1 million.* The minimum liability of $5.1 million has been recorded on the Consolidated Balance Sheet at September 30, 2002. Other than discussed in Note H (referred to below), the Company is currently not aware of any material additional exposure to environmental liabilities. However, adverse changes in environmental regulations or other factors could impact the Company.* The Company is subject to various federal, state and local laws and regulations (including those of the Czech Republic) relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory policies and procedures.

For further discussion refer to Item 8 at Note H - Commitments and Contingencies under the heading "Environmental Matters".

New Accounting Pronouncements

In 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS 142) and SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). For a discussion of SFAS 142 and SFAS 143 and their impact on the Company, see disclosure in Item 8 at Note A – Summary of Significant Accounting Policies.

Effects of Inflation

Although the rate of inflation has been relatively low over the past few years, the Company's operations remain sensitive to increases in the rate of inflation because of its capital spending and the regulated nature of a significant portion of its business.

Approval of Audit and Non-Audit Services

On September 12, 2002, the Company's audit committee approved audit services relating to the audit of the Company's financial statements for the fiscal year ending September 30, 2002, and the provision of comfort letters in connection with securities underwritings. The audit committee also approved certain non-audit services to be performed by the Company's independent accountant, PricewaterhouseCoopers, LLP, including advice concerning methodologies for valuing certain assets, tax advice concerning financing arrangements, and other customary consultation or advice.

Safe Harbor for Forward-Looking Statements

The Company is including the following cautionary statement in this Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including those which are designated with an asterisk ("*"), are "forward-looking" statements as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The forward-looking statements contained herein are based on various assumptions, many of which are based, in turn, upon further assumptions. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Changes in economic conditions, including economic disruptions caused by terrorist activities or acts of war;
2. Changes in demographic patterns and weather conditions;
3. Changes in the availability and/or price of natural gas and oil;
4. Inability to obtain new customers or retain existing ones;
5. Significant changes in competitive factors affecting the Company;
6. Governmental/regulatory actions, initiatives and proceedings, including those affecting acquisitions, financings, allowed rates of return, industry and rate structure, franchise renewal, and environmental/safety requirements;
7. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;
8. Significant changes from expectations in actual capital expenditures and operating expenses and unanticipated project delays or changes in project costs;
9. The nature and projected profitability of pending and potential projects and other investments;

10. Occurrences affecting the Company's ability to obtain funds from operations, debt or equity to finance needed capital expenditures and other investments;
11. Uncertainty of oil and gas reserve estimates;
12. Ability to successfully identify and finance oil and gas property acquisitions and ability to operate and integrate existing and any subsequently acquired business or properties;
13. Ability to successfully identify, drill for and produce economically viable natural gas and oil reserves;
14. Significant changes from expectations in the Company's actual production levels for natural gas or oil;
15. Changes in the availability and/or price of derivative financial instruments;
16. Changes in the price of natural gas or oil and the related effect given the accounting treatment or valuation of financial instruments;
17. Inability of the various counterparties to meet their obligations with respect to the Company's financial instruments;
18. Regarding foreign operations, changes in trade and monetary policies, inflation and exchange rates, taxes, operating conditions, laws and regulations related to foreign operations, and political and governmental changes;
19. Significant changes in tax rates or policies or in rates of inflation or interest;
20. Significant changes in the Company's relationship with its employees or contractors and the potential adverse effects if labor disputes, grievances or shortages were to occur;
21. Changes in accounting principles or the application of such principles to the Company;
22. Changes in laws and regulations to which the Company is subject, including tax, environmental and employment laws and regulations; or
23. The cost and effects of legal and administrative claims against the Company.

The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Refer to the "Market Risk Sensitive Instruments" section in Item 7, MD&A.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements

All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Supplementary Data

Supplementary data that is included in Note L - Quarterly Financial Data (unaudited) and Note N - Supplementary Information for Oil and Gas Producing Activities, appears under this Item, and reference is made thereto.

Report of Management

Management is responsible for the preparation and integrity of the Company's financial statements. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and necessarily include some amounts that are based on management's best estimates and judgment.

The Company maintains a system of internal accounting and administrative controls and an ongoing program of internal audits that management believes provide reasonable assurance that assets are safeguarded and that transactions are properly recorded and executed in accordance with management's authorization. The Company's financial statements have been examined by our independent accountants, PricewaterhouseCoopers LLP, which also conducts a review of internal controls to the extent required by auditing standards generally accepted in the United States of America.

The Audit Committee of the Board of Directors, composed solely of outside directors, meets with management, internal auditors and PricewaterhouseCoopers LLP to review planned audit scope and results and to discuss other matters affecting internal accounting controls and financial reporting. The independent accountants have direct access to the Audit Committee and periodically meet with it without management representatives present.

Report of Independent Accountants

To the Board of Directors
and Shareholders of
National Fuel Gas Company

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2002, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Buffalo, New York
October 23, 2002

Consolidated Statements of Income and Earnings Reinvested in the Business

	Year Ended September 30 (Thousands of Dollars, Except Per Common Share Amounts)	2002	2001	2000
Income	**Operating Revenues**	**$1,464,496**	$2,059,836	$1,412,416
	Operating Expenses			
	Purchased Gas	**462,857**	1,002,466	488,383
	Fuel Used in Heat and Electric Generation	**50,635**	54,968	54,893
	Operation and Maintenance	**394,157**	364,318	350,383
	Property, Franchise and Other Taxes	**72,155**	83,730	78,878
	Depreciation, Depletion and Amortization	**180,668**	174,914	142,170
	Impairment of Oil and Gas Producing Properties	**—**	180,781	—
	Income Taxes	**72,034**	37,106	77,068
		1,232,506	1,898,283	1,191,775
	Operating Income	**231,990**	161,553	220,641
	Operations of Unconsolidated Subsidiaries:			
	Income	**224**	1,794	1,669
	Impairment of Investment in Partnership	**(15,167)**	—	—
		(14,943)	1,794	1,669
	Other Income	**7,017**	10,639	6,366
	Income Before Interest Charges and Minority Interest in Foreign Subsidiaries	**224,064**	173,986	228,676
	Interest Charges			
	Interest on Long-Term Debt	**90,543**	81,851	67,195
	Other Interest	**15,109**	25,294	32,890
		105,652	107,145	100,085
	Minority Interest in Foreign Subsidiaries	**(730)**	(1,342)	(1,384)
	Net Income Available for Common Stock	**117,682**	65,499	127,207
Earnings Reinvested in the Business	Balance at Beginning of Year	**513,488**	525,847	472,517
		631,170	591,346	599,724
	Dividends on Common Stock	**81,773**	77,858	73,877
	Balance at End of Year	**$549,397**	$513,488	$525,847
	Earnings Per Common Share:			
	Basic	**$1.47**	$0.83	$1.63
	Diluted	**$1.46**	$0.82	$1.61
	Weighted Average Common Shares Outstanding:			
	Used in Basic Calculation	**79,821,430**	79,053,444	78,233,842
	Used in Diluted Calculation	**80,534,453**	80,361,258	79,166,200

See Notes to Consolidated Financial Statements

Consolidated Balance Sheets

Assets

At September 30 (Thousands of Dollars)	2002	2001
Property, Plant and Equipment	$4,512,651	$4,273,716
Less - Accumulated Depreciation, Depletion and Amortization	1,667,906	1,493,003
	2,844,745	2,780,713
Current Assets		
Cash and Temporary Cash Investments	22,216	36,227
Receivables – Net	95,510	131,379
Unbilled Utility Revenue	21,918	25,375
Gas Stored Underground	77,250	83,231
Materials and Supplies - at average cost	31,582	33,710
Unrecovered Purchased Gas Costs	12,431	4,113
Prepayments	41,354	39,520
Fair Value of Derivative Financial Instruments	3,807	37,585
	306,068	391,140
Other Assets		
Recoverable Future Taxes	82,385	86,586
Unamortized Debt Expense	20,635	19,796
Other Regulatory Assets	26,104	23,253
Deferred Charges	5,914	8,440
Other Investments	65,090	62,924
Investments in Unconsolidated Subsidiaries	16,753	31,768
Goodwill	8,255	8,804
Other	25,360	31,807
	250,496	273,378
	$3,401,309	$3,445,231

See Notes to Consolidated Financial Statements

Capitalization and Liabilities

At September 30 (Thousands of Dollars)	2002	2001
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued and Outstanding - 80,264,734 Shares and 79,406,105 Shares, Respectively	**$80,265**	$79,406
Paid In Capital	**446,832**	430,618
Earnings Reinvested in the Business	**549,397**	513,488
Total Common Shareholder Equity Before Items Of Other Comprehensive Loss	**1,076,494**	1,023,512
Accumulated Other Comprehensive Loss	**(69,636)**	(20,857)
Total Comprehensive Shareholders' Equity	**1,006,858**	1,002,655
Long-Term Debt, Net of Current Portion	**1,145,341**	1,046,694
Total Capitalization	**2,152,199**	2,049,349
Minority Interest in Foreign Subsidiaries	**28,785**	22,324
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	**265,386**	489,673
Current Portion of Long-Term Debt	**160,564**	109,435
Accounts Payable	**100,886**	123,246
Amounts Payable to Customers	**—**	51,223
Other Accruals and Current Liabilities	**121,518**	89,893
Fair Value of Derivative Financial Instruments	**31,204**	17,081
	679,558	880,551
Deferred Credits		
Accumulated Deferred Income Taxes	**356,220**	340,224
Taxes Refundable to Customers	**15,596**	16,865
Unamortized Investment Tax Credit	**8,897**	9,599
Other Regulatory Liabilities	**82,676**	68,957
Other Deferred Credits	**77,378**	57,362
	540,767	493,007
Commitments and Contingencies	**—**	—
	$3,401,309	$3,445,231

See Notes to Consolidated Financial Statements

Consolidated Statement of Cash Flows

	Year Ended September 30 (Thousands of Dollars)	2002	2001	2000
Operating Activities	Net Income Available for Common Stock	**$117,682**	$65,499	$127,207
	Adjustments to Reconcile Net Income to Net Cash			
	Provided by Operating Activities			
	Impairment of Oil and Gas Producing Properties	**—**	180,781	—
	Depreciation, Depletion and Amortization	**180,668**	174,914	142,170
	Deferred Income Taxes	**62,013**	(55,849)	41,858
	Impairment of Investment in Partnership	**15,167**	—	—
	(Income) Loss from Unconsolidated Subsidiaries,			
	Net of Cash Distributions	**361**	(1,199)	(1,440)
	Minority Interest in Foreign Subsidiaries	**730**	1,342	1,384
	Other	**9,842**	6,553	5,946
	Change in:			
	Receivables and Unbilled Utility Revenue	**40,786**	(2,277)	(26,365)
	Gas Stored Underground and Materials			
	and Supplies	**8,717**	(37,054)	(13,707)
	Unrecovered Purchased Gas Costs	**(8,318)**	25,568	(25,105)
	Prepayments	**(1,737)**	(399)	(3,420)
	Accounts Payable	**(24,025)**	20,419	(16,489)
	Amounts Payable to Customers	**(51,223)**	41,640	3,649
	Other Accruals and Current Liabilities	**(37,372)**	13,969	(10,233)
	Other Assets	**11,869**	(33,169)	826
	Other Liabilities	**20,390**	13,289	11,965
	Net Cash Provided by Operating Activities	**345,550**	414,027	238,246
Investing Activities	Capital Expenditures	**(232,368)**	(292,706)	(269,371)
	Investment in Subsidiaries, Net of Cash Acquired	**—**	(90,567)	(123,809)
	Investment in Partnerships	**(536)**	(1,830)	(4,442)
	Other	**27,080**	(2,823)	13,283
	Net Cash Used in Investing Activities	**(205,824)**	(387,926)	(384,339)
Financing Activities	Change in Notes Payable to Banks			
	and Commercial Paper	**(224,845)**	(143,397)	226,477
	Net Proceeds from Issuance of Long-Term Debt	**243,844**	210,221	149,334
	Reduction of Long-Term Debt	**(104,212)**	(23,052)	(167,426)
	Proceeds from Issuance of Common Stock	**10,915**	11,545	14,278
	Dividends Paid on Common Stock	**(80,974)**	(76,671)	(73,046)
	Dividends Paid to Minority Interest	**—**	—	(152)
	Net Cash (Used in) Provided by Financing Activities	**(155,272)**	(21,354)	149,465
	Effect of Exchange Rates on Cash	**1,535**	(645)	(469)
	Net Increase (Decrease) in Cash and			
	Temporary Cash Investments	**(14,011)**	4,102	2,903
	Cash and Temporary Cash Investments			
	at Beginning of Year	**36,227**	32,125	29,222
	Cash and Temporary Cash Investments at End of Year	**$22,216**	$36,227	$32,125
	Supplemental Disclosure of Cash Flow Information			
	Cash Paid For:			
	Interest	**$98,493**	$100,871	$97,042
	Income Taxes	**29,985**	77,662	41,928

See Notes to Consolidated Financial Statements

Consolidated Statement of Comprehensive Income

Year Ended September 30 (Thousands of Dollars)	2002	2001	2000
Net Income Available for Common Stock	**$117,682**	$65,499	$127,207
Other Comprehensive Income (Loss), Before Tax:			
Minimum Pension Liability Adjustment	**(52,977)**	—	—
Foreign Currency Translation Adjustment	**24,278**	(7,158)	(27,463)
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	**(2,086)**	(712)	2,441
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	**(42,584)**	58,355	—
Reclassification Adjustment for Realized (Gain) Loss on Derivative Financial Instruments in Net Income	**(20,063)**	83,218	—
Reclassification Adjustment for Realized Gain on Securities Available for Sale in Net Income	**—**	—	(103)
Other Comprehensive Income (Loss), Before Tax:	**(93,432)**	133,703	(25,125)
Income Tax Benefit Related to Minimum Pension Liability Adjustment	**(18,542)**	—	—
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	**(730)**	(249)	855
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	**(17,341)**	23,053	—
Reclassification Adjustment for Income Tax (Expense) Benefit on Realized (Gain) Loss on Derivative Financial Instruments In Net Income	**(8,040)**	32,032	—
Reclassification Adjustment for Income Tax Expense on Realized Gain on Securities Available for Sale in Net Income	**—**	—	(36)
Income Taxes – Net	**(44,653)**	54,836	819
Other Comprehensive Income (Loss), Before Cumulative Effect	**(48,779)**	78,867	(25,944)
Cumulative Effect of Change in Accounting, Net of Tax	**—**	(69,767)	—
Other Comprehensive Income (Loss), After Cumulative Effect	**(48,779)**	9,100	(25,944)
Comprehensive Income	**$68,903**	$74,599	$101,263

See Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

NOTE A SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Company consolidates its majority owned subsidiaries. The equity method is used to account for minority owned entities. All significant intercompany balances and transactions are eliminated.

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassification

Certain prior year amounts have been reclassified to conform with current year presentation.

Regulation

The Company is subject to regulation by certain state and federal authorities. The Company has accounting policies which conform to accounting principles generally accepted in the United States of America, as applied to regulated enterprises, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. Reference is made to Note B - Regulatory Matters for further discussion.

In the International segment, rates charged for the sale of thermal energy and electric energy at the retail level are subject to regulation and audit in the Czech Republic by the Czech Ministry of Finance. The regulation of electric energy rates at the retail level indirectly impacts the rates charged by the International segment for its electric energy sales at the wholesale level.

Revenues

Revenues are recorded as bills are rendered, except that service supplied but not billed is reported as unbilled utility revenue and is included in operating revenues for the year in which service is furnished.

Unrecovered Purchased Gas Costs and Refunds

The Company's rate schedules in the Utility segment contain clauses that permit adjustment of revenues to reflect price changes from the cost of purchased gas included in base rates. Differences between amounts currently recoverable and actual adjustment clause revenues, as well as other price changes and pipeline and storage company refunds not yet includable in adjustment clause rates, are deferred and accounted for as either unrecovered purchased gas costs or amounts payable to customers.

Estimated refund liabilities to ratepayers represent management's current estimate of such refunds. Reference is made to Note B - Regulatory Matters for further discussion.

Property, Plant and Equipment

The principal assets of the Utility and Pipeline and Storage segments, consisting primarily of gas plant in service, are recorded at the historical cost when originally devoted to service in the regulated businesses, as required by regulatory authorities.

Oil and gas property acquisition, exploration and development costs are capitalized under the full-cost method of accounting. All costs directly associated with property acquisition, exploration and development activities are capitalized, up to certain specified limits. If capitalized costs exceed these limits at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. As a result of low oil and gas prices, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling for the Company's Canadian properties at September 30, 2001. The Company was required to recognize a $180.8 million ($104.0 million after tax) impairment of its oil and gas producing properties in the quarter ended September 30, 2001.

Maintenance and repairs of property and replacements of minor items of property are charged directly to maintenance expense. The original cost of the regulated subsidiaries' property, plant and equipment retired, and the cost of removal less salvage, are charged to accumulated depreciation.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization are computed by application of either the straight-line method or the units of production method in amounts sufficient to recover costs over the estimated service lives of property in service, and for oil and gas properties, based on quantities produced in relation to proved reserves. The costs of unevaluated oil and gas properties are excluded from this computation. For timber properties, depletion, determined on a property by property basis, is charged to operations based on the annual amount of timber cut in relation to the total amount of recoverable timber. The provisions for depreciation, depletion and amortization, as a percentage of average depreciable property, were 4.4% in 2002, 4.7% in 2001 and 4.2% in 2000 on a consolidated basis.

Cumulative Effect of Change in Accounting

Effective October 1, 2000, the Company adopted the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities – Deferral of the Effective Date of FASB Statement No. 133" and by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of Statement 133" (collectively, SFAS 133). The cumulative effect of this change decreased other comprehensive income by $69.8 million (after tax) at adoption on October 1, 2000. The cumulative effect of this change did not have a material impact on net income at adoption on October 1, 2000. Of the cumulative effect recorded in other comprehensive income, $46.3 million (after tax) was reclassified into the Consolidated Statement of Income during 2001. The derivative financial instruments that comprise the cumulative effect recorded in other comprehensive income have been designated and qualify as cash flow hedges, as discussed below.

Financial Instruments

Unrealized gains or losses from the Company's investments in an equity mutual fund and the stock of an insurance company (securities available for sale) are recorded as a component of accumulated other comprehensive income (loss). Reference is made to Note F - Financial Instruments for further discussion.

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments include price swap agreements, no cost collars, options and futures contracts. As discussed above, on October 1, 2000 the Company adopted SFAS 133. In accordance with the provisions of these standards, the Company accounts for these instruments as either cash flow hedges or fair value hedges. In both cases, the fair value of the instrument is recognized on the Consolidated Balance Sheet as either an asset or a liability labeled fair value of financial instruments. Fair value represents the amount the Company would receive or pay to terminate these instruments.

For effective cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheet. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statement of Income. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2002 or 2001. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues on the Consolidated Statement of Income. For fair value hedges, the offset to the asset or liability that is recorded is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statement of Income. However, in the case of fair value hedges, the Company also records an asset or liability on the Consolidated Balance Sheet representing the change in fair value of the asset or firm commitment that is being hedged. The offset to this asset or liability is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statement of Income as well. If the fair value hedge is effective, the gain or loss from the derivative financial instrument is offset by the gain or loss that arises from the change in fair value of the asset or firm commitment that is being hedged. The Company did not experience any material ineffectiveness with regard to its fair value hedges during 2002 or 2001.

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) are as follows:

Year Ended September 30 (Thousands)	2002	2001
Minimum Pension Liability Adjustment	$(34,435)	$ —
Cumulative Foreign Currency Translation Adjustment	(14,815)	(39,093)
Net Unrealized Gain (Loss) on Derivative Financial Instruments	(20,545)	16,721
Net Unrealized Gain on Securities Available for Sale	159	1,515
Accumulated Other Comprehensive Loss	$(69,636)	$(20,857)

At September 30, 2002, it is estimated that $18.1 million of the net unrealized loss on derivative financial instruments shown in the table above will be reclassified into the Consolidated Statement of Income during 2003.

Gas Stored Underground - Current

In the Utility segment, gas stored underground - current in the amount of $66.4 million is carried at lower of cost or market, on a last-in, first-out (LIFO) method. Based upon the average price of spot market gas purchased in September 2002, including transportation costs, the current cost of replacing this inventory of gas stored underground-current exceeded the amount stated on a LIFO basis by approximately $46.0 million at September 30, 2002. All other gas stored underground - current is carried at lower of cost or market on either an average cost or first-in, first-out method.

Unamortized Debt Expense

Costs associated with the issuance of debt by the Company are deferred and amortized over the lives of the related issues. Costs associated with the reacquisition of debt related to rate-regulated subsidiaries are deferred and amortized over the remaining life of the issue or the life of the replacement debt in order to match regulatory treatment.

Foreign Currency Translation

The functional currency for the Company's foreign operations is the local currency of the country where the operations are located. Asset and liability accounts are translated at the rate of exchange on the balance sheet date. Revenues and expenses are translated at the average exchange rate during the period. Foreign currency translation adjustments are recorded as a component of accumulated other comprehensive income (loss).

Income Taxes

The Company and its domestic subsidiaries file a consolidated federal income tax return. Investment tax credit, prior to its repeal in 1986, was deferred and is being amortized over the estimated useful lives of the related property, as required by regulatory authorities having jurisdiction. No provision has been made for domestic income taxes applicable to certain undistributed earnings of foreign subsidiaries as these amounts are considered to be permanently reinvested outside the United States.

Consolidated Statement of Cash Flows

For purposes of the Consolidated Statement of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. Cash and temporary cash investments includes cash held in margin accounts to serve as collateral for open positions on exchange-traded futures contracts. The amounts held in margin accounts amounted to $0.4 million and $22.5 million at September 30, 2002 and 2001, respectively.

Earnings Per Common Share

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. The only potentially dilutive securities the Company has outstanding are stock options. The diluted weighted average shares outstanding shown on the Consolidated Statement of Income reflects the potential dilution as a result of these stock options as determined using the Treasury Stock Method. Stock options that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2002 and 2001, 5,260,633 and 1,290,747 stock options, respectively, were excluded as being antidilutive.

New Accounting Pronouncements

In 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142) and SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 142 addresses financial accounting and reporting for acquired goodwill and other intangible assets. Under this standard, goodwill and intangible assets that have indefinite useful lives will not be amortized but rather will be tested at least annually for impairment. Intangible assets that have finite useful lives will continue to be amortized over their useful lives, but the amortization period will not be limited to a certain period of time. The Company will adopt SFAS 142 during the first quarter of fiscal 2003 and is in the process of completing its initial impairment test of the goodwill on its balance sheet. The Company does not believe that adoption of SFAS 142 will have a material impact on its financial condition and results of operations.

SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. When the liability is settled, the entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. The Company will adopt SFAS 143 during the first quarter of fiscal 2003. The Company does not believe that adoption of SFAS 143 will have a material impact on its financial condition and results of operations.

NOTE B REGULATORY MATTERS

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

At September 30 (Thousands)	2002	2001
Regulatory Assets:		
Recoverable Future Taxes (Note C)	$82,385	$86,586
Unrecovered Purchased Gas Costs (Note A)	12,431	4,113
Unamortized Debt Expense (Note A)	10,021	11,738
Pension and Post-Retirement Benefit Costs (1) (Note G)	24,146	21,065
Other (1)	1,958	2,188
Total Regulatory Assets	130,941	125,690
Regulatory Liabilities:		
Amounts Payable to Customers (Note A)	—	51,223
New York Rate Settlements (2)	34,323	27,630
Taxes Refundable to Customers (Note C)	15,596	16,865
Pension and Post-Retirement Benefit Costs (2) (Note G)	39,946	33,829
Other (1)	8,407	7,498
Total Regulatory Liabilities	98,272	137,045
Net Regulatory Position	$32,669	$(11,355)

(1) Included in other regulatory assets on the Consolidated Balance Sheets.
(2) Included in other regulatory liabilities on the Consolidated Balance Sheets.

If for any reason the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in income of the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item.

New York Rate Settlements

With respect to utility services provided in New York, the Company has entered into rate settlements approved by the State of New York Public Service Commission (NYPSC). The rate settlements provide for a sharing mechanism, whereby earnings above an 11.5% return on equity are to be shared equally between shareholders and customers. As a result of this sharing mechanism, the Company had liabilities of $9.5 million and $5.8 million at September 30, 2002 and 2001, respectively. Other aspects of the settlements include a special reserve of $6.5 million and $8.2 million at September 30, 2002 and 2001, respectively, to be applied against the Company's incremental costs resulting from the NYPSC's gas restructuring effort and a "refund pool" of $15.3 million and $6.0 million at September 30, 2002 and 2001, respectively. The refund pool is an accumulation of certain refunds from upstream pipeline companies and certain credits which can be used to offset certain specific expense items. Various other regulatory liabilities have also been created through the New York rate settlements and amounted to $3.0 million and $7.7 million at September 30, 2002 and 2001, respectively.

NOTE C INCOME TAXES

The components of federal, state and foreign income taxes included in the Consolidated Statement of Income are as follows:

Year Ended September 30 (Thousands)	2002	2001	2000
Operating Expenses:			
Current Income Taxes -			
Federal	$7,743	$67,429	$26,352
State	1,384	21,330	13,067
Foreign	894	4,196	(4,209)
Deferred Income Taxes -			
Federal	50,205	18,444	29,604
State	9,968	431	2,495
Foreign	1,840	(74,724)	9,759
	72,034	37,106	77,068
Other Income:			
Deferred Investment Tax Credit	(697)	(348)	(1,051)
Minority Interest in Foreign Subsidiaries	(277)	(614)	(259)
Total Income Taxes	$71,060	$36,144	$75,758

The U.S. and foreign components of income (loss) before income taxes are as follows:

Year Ended September 30 (Thousands)	2002	2001	2000
U.S.	$180,349	$267,270	$182,813
Foreign	8,394	(165,627)	20,152
	$188,743	$101,643	$202,965

Total income taxes as reported differ from the amounts that were computed by applying the federal income tax rate to income before income taxes. The following is a reconciliation of this difference:

Year Ended September 30 (Thousands)	2002	2001	2000
Income Tax Expense, Computed at			
U.S. Federal Statutory Rate of 35%	$66,060	$35,575	$71,038
Increase (Reduction) in Taxes Resulting from:			
State Income Taxes	7,379	14,145	10,115
Foreign Tax Rate Differential	(481)	(13,172)	(1,762)
Depreciation	1,744	1,790	1,925
Miscellaneous	(3,642)	(2,194)	(5,558)
Total Income Taxes	$71,060	$36,144	$75,758

Significant components of the Company's deferred tax liabilities and assets are as follows:

At September 30 (Thousands)	2002	2001
Deferred Tax Liabilities:		
Property, Plant and Equipment	$417,673	$389,879
Deferred Gas Costs	5,469	—
Other	22,461	27,047
Total Deferred Tax Liabilities	445,603	416,926
Deferred Tax Assets:		
Deferred Gas Costs	—	(20,178)
Other	(89,383)	(56,524)
Total Deferred Tax Assets	(89,383)	(76,702)
Total Net Deferred Income Taxes	$356,220	$340,224

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $15.6 million and $16.9 million at September 30, 2002 and 2001, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $82.4 million and $86.6 million at September 30, 2002 and 2001, respectively.

Undistributed earnings of foreign subsidiaries of $32 million at September 30, 2002 are considered to be permanently reinvested outside the United States and, accordingly, no U.S. income taxes have been provided thereon. In the event such earnings are distributed in the form of dividends, the Company may be subject to U.S. income taxes and foreign withholding taxes, net of allowable foreign tax credits.

At September 30, 2002, there are Canadian operating loss carryforwards of $23 million which begin to expire if not utilized by the tax year ending September 30, 2006.

NOTE D CAPITALIZATION

SUMMARY OF CHANGES IN COMMON STOCK EQUITY

(Thousands, Except Per Share Amounts)	Common Stock		Paid in Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
	Shares	Amount			
Balance at September 30, 1999	77,674	$77,674	$393,115	$472,517	$(4,013)
Net Income Available for Common Stock				127,207	
Dividends Declared on Common Stock ($0.95 Per Share)				(73,877)	
Other Comprehensive Loss, Net of Tax					(25,944)
Acquisition of Natural Gas Assets	110	110	2,702		
Common Stock Issued Under Stock and Benefit Plans	876	876	17,070		
Balance at September 30, 2000	78,660	78,660	412,887	525,847	(29,957)
Net Income Available for Common Stock				65,499	
Dividends Declared on Common Stock ($0.99 Per Share)				(77,858)	
Other Comprehensive Income, Net of Tax					9,100
Common Stock Issued Under Stock and Benefit Plans	746	746	17,731		
Balance at September 30, 2001	79,406	79,406	430,618	513,488	(20,857)
Net Income Available for Common Stock				**117,682**	
Dividends Declared on Common Stock ($1.03 Per Share)				**(81,773)**	
Other Comprehensive Loss, Net of Tax					**(48,779)**
Common Stock Issued Under Stock and Benefit Plans	**859**	**859**	**16,214**		
Balance at September 30, 2002	**80,265**	**$80,265**	**$446,832**	**$549,397**(1)	**$(69,636)**

(1) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2002, $475.0 million of accumulated earnings was free of such limitations.

Common Stock

The Company has various plans which allow shareholders, customers and employees to purchase shares of Company common stock. The National Fuel Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends or make cash investments in the Company's common stock and provides investors the opportunity to acquire shares of Company common stock without the payment of any brokerage commissions or service charges in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in Company common stock, in addition to a variety of other investment alternatives. At the discretion of the Company, shares purchased under these plans are either original issue shares purchased directly from the Company or shares purchased on the open market by an independent agent.

The Company also has a Director Stock Program under which it issues shares of Company common stock to its non-employee directors as partial consideration for their services as directors.

Shareholder Rights Plan

In 1996, the Company's Board of Directors adopted a shareholder rights plan (Plan). Effective April 30, 1999, the Plan was amended and is now embodied in an Amended and Restated Rights Agreement, under which the Board of Directors made adjustments in connection with the two-for-one stock split of September 7, 2001.

The holders of the Company's common stock have one right (Right) for each of their shares. Each Right, which will initially be evidenced by the Company's common stock certificates representing the outstanding shares of common stock, entitles the holder to purchase one-half of one share of common stock at a purchase price of $65.00 per share, being $32.50 per half share, subject to adjustment (Purchase Price).

The Rights become exercisable upon the occurrence of a distribution date. At any time following a distribution date, each holder of a Right may exercise its right to receive common stock (or, under certain circumstances, other property of the Company) having a value equal to two times the Purchase Price of the Right then in effect. However, the Rights are subject to redemption or exchange by the Company prior to their exercise as described below.

A distribution date would occur upon the earlier of (i) ten days after the public announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of the Company's common stock or other voting stock having 10% or more of the total voting power of the Company's common stock and other voting stock and (ii) ten days after the commencement or announcement by a person or group of an intention to make a tender or exchange offer that would result in that person acquiring, or obtaining the right to acquire, beneficial ownership of the Company's common stock or other voting stock having 10% or more of the total voting power of the Company's common stock and other voting stock.

In certain situations after a person or group has acquired beneficial ownership of 10% or more of the total voting power of the Company's stock as described above, each holder of a Right will have the right to exercise its Rights to receive common stock of the acquiring company having a value equal to two times the Purchase Price of the Right then in effect. These situations would arise if the Company is acquired in a merger or other business combination or if 50% or more of the Company's assets or earning power are sold or transferred.

At any time prior to the end of the business day on the tenth day following the announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of 10% or more of the total voting power of the Company, the Company may redeem the Rights in whole, but not in part, at a price of $0.005 per Right, payable in cash or stock. A decision to redeem the Rights requires the vote of 75% of the Company's full Board of Directors. Also, at any time following the announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of 10% or more of the total voting power of the Company, 75% of the Company's full Board of Directors may vote to exchange the Rights, in whole or in part, at an exchange rate of one share of common stock, or other property deemed to have the same value, per Right, subject to certain adjustments.

After a distribution date, Rights that are owned by an acquiring person will be null and void. Upon exercise of the Rights, the Company may need additional regulatory approvals to satisfy the requirements of the Rights Agreement. The Rights will expire on July 31, 2008, unless they are exchanged or redeemed earlier than that date.

The Rights have anti-takeover effects because they will cause substantial dilution of the common stock if a person attempts to acquire the Company on terms not approved by the Board of Directors.

Stock Option and Stock Award Plans

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, stock appreciation rights, restricted stock, performance units or performance shares. Stock options under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no option is exercisable less than one year or more than ten years after the date of each grant.

For the years ended September 30, 2002, 2001 and 2000, no compensation expense was recognized for options granted under these plans. Had compensation expense for stock options granted under the Company's stock option and stock award plans been determined based on fair value at the grant dates, the Company's net income and earnings per share would have been reduced to the pro forma amounts below:

Year Ended September 30	2002	2001	2000
Net Income *(Thousands):*			
As reported	**$117,682**	$65,499	$127,207
Pro forma	**$113,041**	$59,108	$123,107
Earnings Per Common Share:			
Basic - As reported	**$1.47**	$0.83	$1.63
Basic - Pro forma	**$1.42**	$0.75	$1.58
Diluted - As reported	**$1.46**	$0.82	$1.61
Diluted - Pro forma	**$1.40**	$0.73	$1.56

Transactions involving option shares for all plans are summarized as follows:

	Number of Shares Subject to Option	Weighted Average Exercise Price
Outstanding at September 30, 1999	6,728,184	$19.65
Granted in 2000	1,782,200	$21.87
Exercised in 2000 (1)	(455,484)	$15.08
Forfeited in 2000	(27,800)	$23.08
Outstanding at September 30, 2000	8,027,100	$20.38
Granted in 2001	1,787,200	$27.61
Exercised in 2001 (1)	(372,040)	$15.89
Forfeited in 2001	(69,574)	$22.36
Outstanding at September 30, 2001	9,372,686	$21.92
Granted in 2002 (2)	**5,673,172**	**$22.26**
Exercised in 2002 (1)	**(247,910)**	**$15.76**
Forfeited in 2002	**(168,444)**	**$25.56**
Outstanding at September 30, 2002	**14,629,504**	**$22.12**
Option shares exercisable at September 30, 2002	**11,766,044**	**$21.68**
Option shares available for future grant at September 30, 2002 (3)	**942,669**	

(1) In connection with exercising these options, 43,834, 78,850 and 116,916 shares were surrendered and canceled during 2002, 2001 and 2000, respectively.
(2) Including 3,097,172 non-qualified stock options issued in November 2001. The Company canceled 3,097,172 stock appreciation rights (SARs) in November 2001 and issued 3,097,172 non-qualified stock options. The Company eliminated all future awards of SARs.
(3) Including shares available for restricted stock grants.

The weighted average fair value per share of options granted in 2002, 2001 and 2000 was $4.32, $5.25 and $4.17, respectively. These weighted average fair values were estimated on the date of grant using a binomial option pricing model with the following weighted average assumptions:

Year Ended September 30	2002	2001	2000
Quarterly Dividend Yield	**1.07%**	0.87%	1.07%
Annual Standard Deviation (Volatility)	**21.83%**	20.51%	19.05%
Risk Free Rate	**4.88%**	5.26%	6.74%
Expected Term - in Years	**5.5**	5.0	5.5

The following table summarizes information about options outstanding at September 30, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number Outstanding at 9/30/02	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 9/30/02	Weighted Average Exercise Price
$11.12 - $16.68	**1,635,916**	**2.2 years**	**$14.91**	**1,635,916**	**$14.91**
$16.69 - $22.24	**4,572,226**	**5.9 years**	**$20.31**	**4,291,226**	**$20.21**
$22.25 - $27.80	**8,421,362**	**7.5 years**	**$24.50**	**5,838,902**	**$24.66**

Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. The market value of restricted stock on the date of the award is being recorded as compensation expense over the periods during which the vesting restrictions exist. Certificates for shares of restricted stock awarded under the Company's stock option and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective.

The following table summarizes the awards of restricted stock over the past three years:

Year Ended September 30	2002	2001	2000
Shares of Restricted Stock Awarded	**100,000**	4,000	15,178
Weighted Average Market Price of Stock on Award Date	**$24.50**	$27.80	$24.47

As of September 30, 2002, 149,728 shares of non-vested restricted stock were outstanding. Vesting restrictions will lapse as follows: 2003 – 13,600 shares; 2004 – 36,600 shares; 2005 – 34,600 shares; 2006 – 34,600 shares; 2007 – 29,000 shares; and 2010 - 1,328 shares.

Compensation expense related to restricted stock under the Company's stock plans was $0.7 million, $0.3 million and $0.7 million for the years ended September 30, 2002, 2001 and 2000, respectively.

Redeemable Preferred Stock

As of September 30, 2002, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

Long-Term Debt

The outstanding long-term debt is as follows:

At September 30 (Thousands)	2002	2001
Debentures:		
7-3/4% due February 2004	$125,000	$125,000
Medium-Term Notes:		
6.00% to 8.48% due February 2003 to August 2027 (1)	1,051,300	999,000
Senior Unsecured Notes:		
6.50% due September 2022 (2)	97,700	—
	1,274,000	1,124,000
Other Notes	31,905	32,129
Total Long-Term Debt	1,305,905	1,156,129
Less Current Portion	160,564	109,435
	$1,145,341	$1,046,694

(1) Includes $50 million of 8.48% medium-term notes due July 2024 which are callable at a redemption price of 105.09% through July 2003. The redemption price will decline in subsequent years.
(2) These notes are callable at par at any time after September 15, 2006. The estate of an individual note holder may exercise a put option in the event of death of an individual note holder.

As of September 30, 2002, the aggregate principal amounts of long-term debt maturing for the next five years and thereafter are as follows: $160.6 million in 2003, $235.6 million in 2004, $6.2 million in 2005, $4.4 million in 2006, none in 2007 and $899.1 million thereafter.

NOTE E SHORT-TERM BORROWINGS

The Company has SEC authorization under the Public Utility Holding Company Act of 1935, as amended, to borrow and have outstanding as much as $750.0 million of short-term debt at any time through December 31, 2005.

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. As for the former, the Company maintains uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines are revocable at the option of the financial institutions and are reviewed on an annual basis. The commercial paper program is backed by a committed $220 million, 364-day and 3-year credit facility, which was effective on September 30, 2002.

At September 30, 2002, the Company had outstanding short-term notes payable to banks and commercial paper of $91.3 million (domestic = $79.9 million; foreign = $11.4 million) and $174.1 million, respectively. At September 30, 2001, the Company had outstanding notes payable to banks and commercial paper of $289.7 million (domestic = $259.9 million; foreign = $29.8 million) and $200.0 million, respectively.

The weighted average interest rate on domestic notes payable to banks was 2.05% and 3.39% at September 30, 2002 and 2001, respectively. The interest rate on the foreign notes payable to banks was 3.64% and 4.65% at September 30, 2002 and 2001, respectively. The weighted average interest rate on commercial paper was 2.04% and 3.13% at September 30, 2002 and 2001, respectively.

NOTE F FINANCIAL INSTRUMENTS

Fair Values

The fair market value of the Company's long-term debt is estimated based on quoted market prices of similar issues having the same remaining maturities, redemption terms and credit ratings. Based on these criteria, the fair market value of long-term debt, including current portion, was as follows:

At September 30 (Thousands)	2002 Carrying Amount	2002 Fair Value	2001 Carrying Amount	2001 Fair Value
Long-Term Debt	**$1,305,905**	**$1,393,949**	$1,156,129	$1,186,795

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay.

Temporary cash investments, notes payable to banks and commercial paper are stated at amounts which approximate their fair value due to the short-term maturities of those financial instruments. Investments in life insurance are stated at their cash surrender values as discussed below. Investments in an equity mutual fund and the stock of an insurance company (marketable equity securities), as discussed below, are stated at fair value based on quoted market prices.

Other Investments

Other investments includes cash surrender values of insurance contracts and marketable equity securities. The cash surrender values of the insurance contracts amounted to $57.1 million and $52.9 million at September 30, 2002 and 2001, respectively. The fair value of the equity mutual fund was $3.8 million and $4.8 million at September 30, 2002 and 2001, respectively. The gross unrealized loss on the equity mutual fund was $1.5 million and $0.4 million at September 30, 2002 and 2001, respectively. The fair value of the stock of an insurance company was $4.2 million and $5.2 million at September 30, 2002 and 2001, respectively. The gross unrealized gain on this stock was $1.7 million and $2.7 million at September 30, 2002 and 2001, respectively. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with the fluctuations in the price of natural gas and crude oil. These instruments include price swap agreements, no cost collars, options and futures contracts.

Under the price swap agreements, the Company receives monthly payments from (or makes payments to) other parties based upon the difference between a fixed price and a variable price as specified by the agreement. The variable price is either a crude oil price quoted on the New York Mercantile Exchange (NYMEX) or a quoted natural gas price in "Inside FERC." These derivative financial instruments are accounted for as cash flow hedges and are used to lock in a price for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment. At September 30, 2002, the Company had natural gas price swap agreements covering a notional amount of 18.5 Bcf extending through 2004 at a weighted average fixed rate of $3.73 per Mcf. The Company also had crude oil price swap agreements covering a notional amount of 3,252,000 bbls extending through 2003 at a weighted average fixed rate of $21.28 per bbl. At September 30, 2002, the Company would have had to pay a net $29.0 million to terminate the price swap agreements.

Under the no cost collars, the Company receives monthly payments from (or makes payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). The variable price is either a crude oil price quoted on the NYMEX or a quoted natural gas price in "Inside FERC." These derivative financial instruments are accounted for as cash flow hedges and are used to lock in a price range for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment. At September 30, 2002, the Company had no cost collars on natural gas covering a notional amount of 8.8 Bcf extending through 2004 with a weighted average floor price of $3.80 per Mcf and a weighted average ceiling price of $5.71 per Mcf. The Company also had no cost collars on crude oil covering a notional amount of 1,395,000 bbls extending through 2004 with a weighted average floor price of $21.97 per bbl and a weighted average ceiling price of $26.29 per bbl. At September 30, 2002, the Company would have had to pay $0.7 million to terminate the no cost collars.

At September 30, 2002, the Company had purchased call and put options outstanding on natural gas extending through 2003. The call options purchased by the Energy Marketing segment cover a notional amount of 0.2 Bcf at a weighted average strike price of $4.73 per Mcf. The put options, purchased by the Exploration and Production segment cover a notional amount of 0.2 Bcf at a weighted average strike price of $3.98 per Mcf. These derivative financial instruments are accounted for as cash flow hedges. The call options are used to establish a ceiling price (the Company receives payment from the counterparty when a variable price rises above the ceiling price) for the anticipated purchase of natural gas in the Energy Marketing segment. At September 30, 2002, the Company would have received $0.1 million to terminate these call options. The put options are used to establish a floor price (the Company receives payment from the counterparty when a variable price falls below the floor price) for the anticipated sale of natural gas in the Exploration and Production segment. At September 30, 2002, the Company would have received $0.1 million to terminate these put options.

At September 30, 2002, the Company had long (purchased) futures contracts covering 7.2 Bcf of gas extending through 2004 at a weighted average contract price of $3.71 per Mcf. These derivative financial instruments are accounted for as fair value hedges. They are used by the Company's Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed due to the fixed price gas sales commitments that it enters into with commercial and industrial customers. The Company would have received $5.4 million to terminate these futures contracts at September 30, 2002.

At September 30, 2002, the Company had short (sold) futures contracts covering 3.8 Bcf of gas extending through 2003 at a weighted average contract price of $3.68 per Mcf. Of this amount, 3.6 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Energy Marketing segment. The remaining 0.2 Bcf is accounted for as fair value hedges, since these contracts hedge against falling prices, a risk to which the Energy Marketing segment and All Other category are exposed on their gas storage inventory and fixed price gas purchase commitments. The Company would have had to pay $3.3 million to terminate these futures contracts at September 30, 2002.

The Company may be exposed to credit risk on some of its derivative financial instruments. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on an ongoing basis monitors counterparty credit exposure. Management has obtained guarantees from the parent companies of the respective counterparties to its derivative financial instruments. At September 30, 2001, the Company used five counterparties for its over the counter derivative financial instruments. To further reduce credit risk, the Company increased the number of its counterparties to seven at September 30, 2002. At September 30, 2002, no individual counterparty represented greater than 25% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company's total volumes hedged).

NOTE G RETIREMENT PLAN AND OTHER POST-RETIREMENT BENEFITS

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan) that covers substantially all domestic employees of the Company. The Company provides health care and life insurance benefits for substantially all domestic retired employees under a post-retirement benefit plan (Post-Retirement Plan).

The Company's policy is to fund the Retirement Plan with at least an amount necessary to satisfy the minimum funding requirements of applicable laws and regulations and not more than the maximum amount deductible for federal income tax purposes. The Company has established Voluntary Employees' Beneficiary Association (VEBA) trusts for its Post-Retirement Plan. Contributions to the VEBA trusts are tax deductible, subject to limitations contained in the Internal Revenue Code and regulations and are made to fund employees' post-retirement health care and life insurance benefits, as well as benefits as they are paid to current retirees. Retirement Plan and Post-Retirement Plan assets primarily consist of equity and fixed income investments or units in commingled funds or money market funds.

The Company expects to recover substantially all of its net periodic pension and post-retirement benefit costs in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorization. For financial reporting purposes, the difference between the amounts of pension cost and post-retirement benefit cost recoverable in rates and the amounts of such costs as determined under applicable accounting principles is recorded as either a regulatory asset or liability, as appropriate. Pension and post-retirement benefit costs reflect the amount recovered from customers in rates during the year. Under the NYPSC's policies, the Company segregates the amount of such costs collected in rates, but not yet contributed to the Retirement and Post-Retirement Plans, into a regulatory liability account. This liability accrues interest at the NYPSC-mandated interest rate, and this interest cost is included in pension and post-retirement benefit costs. For purposes of disclosure, the liability also remains in the disclosed pension and post-retirement benefit liability amount because it has not yet been contributed.

Retirement Plan

Reconciliations of the Benefit Obligation, Retirement Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions are as follows:

Year Ended September 30 (Thousands)	2002	2001	2000
Change in Benefit Obligation			
Benefit Obligation at Beginning of Period	**$580,046**	$535,894	$538,796
Service Cost	**11,639**	11,550	11,692
Interest Cost	**40,720**	39,061	37,954
Amendments	**420**	2,343	—
Actuarial (Gain) Loss	**28,880**	25,358	(20,216)
Benefits Paid	**(36,235)**	(34,160)	(32,332)
Benefit Obligation at End of Period	**$625,470**	$580,046	$535,894
Change in Plan Assets			
Fair Value of Assets at Beginning of Period	**$536,625**	$569,936	$537,958
Actual Return on Plan Assets	**(29,898)**	(19,248)	36,584
Employer Contribution	**15,435**	20,097	27,726
Benefits Paid	**(36,235)**	(34,160)	(32,332)
Fair Value of Assets at End of Period	**$485,927**	$536,625	$569,936
Reconciliation of Funded Status			
Funded Status	**$(139,543)**	$(43,421)	$34,042
Unrecognized Net Actuarial Loss (Gain)	**132,064**	23,222	(62,008)
Unrecognized Transition Asset	**(3,716)**	(7,432)	(11,148)
Unrecognized Prior Service Cost	**11,451**	12,236	10,943
Prepaid (Accrued) Benefit Cost	**$256**	$(15,395)	$(28,171)
Accumulated Benefit Obligation	**$550,099**	$510,155	$464,334
Amounts Recognized in the Balance Sheets			
Consist of:			
Prepaid Benefit Cost	**$256**	$ —	$ —
Accrued Benefit Cost	**(64,428)**	(15,395)	(28,171)
Intangible Asset	**11,451**	—	—
Accumulated Other Comprehensive Loss (Pre Tax)	**52,977**	—	—
Net Amount Recognized	**$256**	$(15,395)	$(28,171)

	2002	2001	2000
Weighted Average Assumptions as of September 30			
Discount Rate	**6.75%**	7.25%	7.50%
Expected Return on Plan Assets	**8.50%**	8.50%	8.50%
Rate of Compensation Increase	**6.11%**	6.11%	5.00%
Year Ended September 30 (Thousands)			
Components of Net Periodic Benefit Cost			
Service Cost	**$11,639**	$11,550	$11,692
Interest Cost	**40,720**	39,061	37,954
Expected Return on Plan Assets	**(48,454)**	(45,703)	(41,077)
Amortization of Prior Service Cost	**1,205**	1,050	1,106
Amortization of Transition Amount	**(3,716)**	(3,716)	(3,716)
Recognition of Actuarial (Gain) or Loss	**(1,061)**	(2,256)	60
Early Retirement Window	**—**	7,337	—
Net Amortization and Deferral for Regulatory Purposes	**7,379**	4,787	206
Net Periodic Benefit Cost	**$7,712**	$12,110	$6,225
Other Comprehensive Loss (Pre Tax) Attributable to Change In Additional Minimum Liability Recognition	**$52,977**	$ —	$ —

In accordance with the provisions of SFAS No. 87, "Employers' Accounting for Pensions," the Company recorded an additional minimum liability at September 30, 2002 representing the excess of the accumulated benefit obligation over the fair value of plan assets plus accrued amounts previously recorded. An intangible asset, as shown in the table above, has offset the additional liability to the extent of previously Unrecognized Prior Service Cost. The amount in excess of Unrecognized Prior Service Cost is recorded net of the related tax benefit as accumulated other comprehensive loss. The pre tax amount of the accumulated other comprehensive loss is shown in the table above.

The effects of the discount rate changes in 2002 and 2001 were to increase the Benefit Obligation by $34.0 million and $15.6 million as of the end of each period, respectively.

Other Post-Retirement Benefits

Reconciliations of the Benefit Obligation, Post-Retirement Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions are as follows:

Year Ended September 30 (Thousands)	2002	2001	2000
Change in Benefit Obligation			
Benefit Obligation at Beginning of Period	$304,548	$266,460	$255,615
Service Cost	4,658	4,234	4,156
Interest Cost	21,617	19,557	18,142
Plan Participants' Contributions	610	524	414
Amendments	—	33	—
Actuarial (Gain) Loss	76,972	26,661	(355)
Benefits Paid	(14,554)	(12,921)	(11,512)
Benefit Obligation at End of Period	$393,851	$304,548	$266,460
Change in Plan Assets			
Fair Value of Assets at Beginning of Period	$161,959	$176,357	$149,884
Actual Return on Plan Assets	(18,181)	(19,685)	18,527
Employer Contribution	20,459	17,684	19,044
Plan Participants' Contributions	610	524	414
Benefits Paid	(14,554)	(12,921)	(11,512)
Fair Value of Assets at End of Period	$150,293	$161,959	$176,357
Reconciliation of Funded Status			
Funded Status	$(243,558)	$(142,589)	$(90,103)
Unrecognized Net Actuarial (Gain) Loss	157,247	52,832	(8,676)
Unrecognized Transition Obligation	78,399	85,526	92,653
Unrecognized Prior Service Cost	30	33	—
Accrued Benefit Cost	$(7,882)	$(4,198)	$(6,126)

	2002	2001	2000
Weighted Average Assumptions as of September 30			
Discount Rate	6.75%	7.25%	7.50%
Expected Return on Plan Assets	8.50%	8.50%	8.50%
Rate of Compensation Increase	6.11%	6.11%	5.00%
Year Ended September 30 (Thousands)			
Components of Net Periodic Benefit Cost			
Service Cost	$4,658	$4,234	$4,156
Interest Cost	21,617	19,557	18,142
Expected Return on Plan Assets	(13,551)	(14,787)	(12,574)
Amortization of Transition Obligation	7,127	7,127	7,127
Amortization of (Gain) Loss	4,289	(374)	(24)
Net Amortization and Deferral for Regulatory Purposes	(729)	4,075	7,269
Net Periodic Benefit Cost	$23,411	$19,832	$24,096

The effects of the discount rate changes in 2002 and 2001 were to increase the Benefit Obligation by $21.7 million and $9.8 million as of the end of each period, respectively.

The health care trend assumptions were changed in 2002 to better reflect anticipated future experience. The effect of the changed medical care, prescription drug and Medicare Part B assumptions was to increase the Accumulated Postretirement Benefit Obligation by $57.9 million. In 2000, the impact of changes in health care trend assumptions was an increase in the Accumulated Postretirement Benefit Obligation of $13.7 million.

The annual rate of increase in the per capita cost of covered medical care benefits was assumed to be 10.0% for 2000, 9.0% for 2001, 12% for 2002 and gradually decline to 5.5% by the year 2005 and remain level thereafter. The annual rate of increase for medical care benefits provided by healthcare maintenance organizations was assumed to be 10.0% in 2000, 9.0% in 2001, 12% in 2002 and gradually decline to 5.5% by the year 2005 and remain level thereafter. The annual rate of increase in the per capita cost of covered prescription drug benefits was assumed to be 15.0% for 2000, 13.0% for 2001, 15% for 2002 and gradually decline to 5.5% by the year 2005 and remain level thereafter. The annual rate of increase in the per capita Medicare Part B Reimbursement was assumed to be 10.0% for 2000, 9.0% for 2001, 8% for 2002 and gradually decline to 5.5% by the year 2005 and remain level thereafter.

The health care cost trend rate assumptions used to calculate the per capita cost of covered medical care benefits have a significant effect on the amounts reported. If the health care cost trend rates were increased by 1% in each year, the Benefit Obligation as of October 1, 2002 would be increased by $58.2 million. This 1% change would also have increased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2002 by $4.3 million. If the health care cost trend rates were decreased by 1% in each year, the Benefit Obligation as of October 1, 2002 would be decreased by $47.8 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2002 by $3.5 million.

NOTE H COMMITMENTS AND CONTINGENCIES

Environmental Matters

The Company is subject to various federal, state and local laws and regulations (including those of the Czech Republic) relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures.

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. The Company has estimated its remaining clean-up costs related to the sites described below in paragraphs (i) and (ii) will be in the range of $5.1 million to $6.1 million. The minimum estimated liability of $5.1 million has been recorded on the Consolidated Balance Sheet at September 30, 2002. Other than as discussed below, the Company is currently not aware of any material exposure to environmental liabilities. However, adverse changes in environmental regulations, new information or other factors could impact the Company.

(i) Former Manufactured Gas Plant Sites

The Company has incurred or is incurring clean-up costs at four former manufactured gas plant sites in New York and Pennsylvania. Remediation is substantially complete at a site where the Company has been designated by the New York Department of Environmental Conservation (DEC) as a potentially responsible party (PRP). The Company is engaged in litigation regarding that site with the DEC and the party who bought the site from the Company's predecessor. At a second site, remediation is complete. At a third site, the Company is negotiating with the DEC for clean-up under a voluntary program. The fourth site, which allegedly contains, among other things, manufactured gas plant waste, is in the investigation stage.

(ii) Third Party Waste Disposal Sites

The Company has been identified by the DEC or the United States Environmental Protection Agency as one of a number of companies considered to be PRPs with respect to two waste disposal sites in New York which were operated by unrelated third parties. The PRPs are alleged to have contributed to the materials that may have been collected at such waste disposal sites by the site operators. The ultimate cost to the Company with respect to the remediation of these sites will depend on such factors as the remediation plan selected, the extent of site contamination, the number of additional PRPs at each site and the portion of responsibility, if any, attributed to the Company. The remediation has been completed at one site, with final payments pending. At a second waste disposal site, settlement was reached in the amount of $5.5 million to be allocated among five PRPs. The allocation process is currently being determined. Further negotiations remain in process for additional settlements related to this site.

(iii) Other

The Company received, in 1998 and again in October 1999, notice that the DEC believes the Company is responsible for contamination discovered at an additional former manufactured gas plant site in New York. The Company, however, has not been named as a PRP. The Company responded to these notices that other companies operated that site before its predecessor did, that liability could be imposed upon it only if hazardous substances were disposed at the site during a period when the site was operated by its predecessor, and that it was unaware of any such disposal. The Company has not incurred any clean-up costs at this site nor has it been able to reasonably estimate the probability or extent of potential liability.

Other

The Company, in its Utility segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase capacity on nonaffiliated pipelines to meet customer gas supply needs. The majority of these contracts (representing 95% of contracted demand capacity) expire within the next five years. Costs incurred under these contracts are purchased gas costs, subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

In October 2002, the Company announced its intention to buy the Empire State Pipeline (Empire) from Duke Energy Corporation for $180.0 million in cash plus assumed debt of $60.0 million. Empire is a 157-mile, 24-inch pipeline that begins at the United States/Canadian border at the Chippawa Channel of the Niagara River near Buffalo, New York, which is within the Company's service territory, and terminates in Central New York just north of Syracuse, New York. Empire is regulated by the NYPSC. Empire can transport 525 million cubic feet of gas per day and currently has almost all of its capacity under contract, with a substantial portion being long-term contracts. Empire delivers natural gas supplies to major industrial companies, utilities (including the Company's Utility segment), and power producers. Empire would better position the Company to bring Canadian gas supplies into the East Coast markets of the United States as demand for natural gas along the East Coast increases. The Company notified the Department of Justice and Federal Trade Commission of the proposed acquisition as required under the antitrust laws, and the Company's request for early termination of the antitrust waiting period has been granted. The Company has also made a filing seeking approval of the transaction from the NYPSC. Subject to NYPSC approval, it is anticipated that the purchase will be completed in the beginning of calendar 2003.

The Company is involved in litigation arising in the normal course of its business. In addition to the regulatory matters discussed in Note B - Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business that involve rate base, cost of service and purchased gas cost issues. While the resolution of such litigation or other regulatory matters could have a material effect on earnings and cash flows in the year of resolution, none of this litigation, and none of these other regulatory matters, are currently expected to have a material adverse effect on the financial condition of the Company.

NOTE I BUSINESS SEGMENT INFORMATION

The Company has six reportable segments: Utility, Pipeline and Storage, Exploration and Production, International, Energy Marketing and Timber. The breakdown of the Company's reportable segments is based upon a combination of factors including differences in products and services, regulatory environment and geographic factors.

The Utility segment operations are regulated by the NYPSC and the Pennsylvania Public Utility Commission (PaPUC) and are carried out by Distribution Corporation. Distribution Corporation sells natural gas to retail customers and provides natural gas transportation services in western New York and northwestern Pennsylvania.

The Pipeline and Storage segment operations are regulated by the Federal Energy Regulatory Commission (FERC) and are carried out by Supply Corporation. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers (including NFR) and pipeline companies in the northeastern United States markets. SIP, although not regulated itself by FERC, holds a one-third partnership interest in the Independence Pipeline Company (Independence), whose rates, services and other matters were anticipated to be regulated by FERC. As discussed in Note J – Investments in Unconsolidated Subsidiaries, SIP wrote off its investment in Independence in June 2002. As shown in the table below, this impairment amounted to $15.2 million. On September 30, 2002, Independence was dissolved.

The Exploration and Production segment, through Seneca, is engaged in exploration for, and development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, in Wyoming, in the Gulf Coast region of Texas and Louisiana and in the provinces of Manitoba, Alberta, Saskatchewan and British Columbia in Canada. Seneca's production is, for the most part, sold to purchasers located in the vicinity of its wells.

The International segment's operations are carried out by Horizon. Horizon engages in foreign energy projects through the investment of its indirect subsidiaries as the sole or partial owner of various business entities. Horizon's current emphasis is the Czech Republic, where, through its subsidiaries, it owns majority interests in companies having district heating and power generation plants in the northern Bohemia region.

The Energy Marketing segment is comprised of NFR's operations. NFR markets natural gas to industrial, commercial, public authority and residential end-users in western and central New York and northwestern Pennsylvania, offering competitively priced energy and energy management services for its customers.

The Timber segment's operations are carried out by the Northeast division of Seneca and by Highland. This segment has timber holdings (primarily high quality hardwoods) in the northeastern United States and several sawmills and kilns in Pennsylvania.

The data presented in the tables below reflect the reportable segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A - Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. Expenditures for long-lived assets include additions to property, plant and equipment and equity investments in corporations (stock acquisitions) or partnerships, net of any cash acquired. The Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income.

Year Ended September 30, 2002 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	International	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$776,577	$80,165	$310,980	$95,315	$151,257	$47,407	$1,461,701	$2,795	$ —	$1,464,496
Intersegment Revenues	17,644	87,219	—	—	—	—	104,863	7,340	(112,203)	—
Interest Expense	30,790	10,424	55,367	8,045	76	2,896	107,598	420	(2,366)	105,652
Depreciation, Depletion and Amortization	37,412	23,626	103,946	11,977	161	3,429	180,551	115	2	180,668
Income Tax Expense	31,657	18,148	15,108	(2,030)	5,103	4,476	72,462	(473)	45	72,034
Significant Non-cash Item: Impairment of Investment in Partnership	—	15,167	—	—	—	—	15,167	—	—	15,167
Segment Profit (Loss): Net Income	49,505	29,715	26,851	(4,443)	8,642	9,689	119,959	(885)	(1,392)	117,682
Expenditures for Additions to Long-Lived Assets	51,550	30,329	114,602	4,244	51	25,574	226,350	6,554	—	232,904
At September 30, 2002 (Thousands)										
Segment Assets	$1,248,426	$532,543	$1,161,310	$241,466	$52,850	$131,721	$3,368,316	$33,563	$(570)	$3,401,309

Year Ended September 30, 2001 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	International	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$1,214,614	$81,057	$355,005	$97,910	$259,206	$44,914	$2,052,706	$7,130	$ —	$2,059,836
Intersegment Revenues	20,033	90,034	—	—	—	—	110,067	11,192	(121,259)	—
Interest Expense	27,489	12,131	56,291	9,966	1,649	3,830	111,356	692	(4,903)	107,145
Depreciation, Depletion and Amortization	36,607	23,746	98,408	12,634	212	3,186	174,793	119	2	174,914
Income Tax Expense	42,985	29,091	(36,075)	253	(1,660)	4,566	39,160	(2,281)	227	37,106
Significant Non-cash Item: Impairment of Oil and Gas Producing Properties	—	—	180,781	—	—	—	180,781	—	—	180,781
Segment Profit (Loss): Net Income	60,707	40,377	(32,284)	(3,042)	(3,432)	7,715	70,041	(4,277)	(265)	65,499
Expenditures for Additions to Long-Lived Assets	42,374	25,978	296,419	15,585	116	3,694	384,166	937	—	385,103
At September 30, 2001 (Thousands)										
Segment Assets	$1,284,189	$549,991	$1,194,393	$206,361	$68,178	$113,294	$3,416,406	$26,858	$1,967	$3,445,231

Year Ended September 30, 2000 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	International	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$827,231	$81,434	$222,611	$104,736	$133,929	$41,545	$1,411,486	$930	$ —	$1,412,416
Intersegment Revenues	19,228	88,225	225	—	—	—	107,678	4,415	(112,093)	—
Interest Expense	31,655	13,311	42,034	12,353	774	4,750	104,877	262	(5,054)	100,085
Depreciation, Depletion and Amortization	35,842	23,379	69,583	11,110	209	1,948	142,071	97	2	142,170
Income Tax Expense	38,362	22,172	19,413	(1,783)	(4,372)	3,816	77,608	(205)	(335)	77,068
Segment Profit (Loss): Net Income	57,662	31,614	34,877	3,282	(7,790)	6,133	125,778	(371)	1,800	127,207
Expenditures for Additions to Long-Lived Assets	55,799	35,806[1]	280,049	9,767	89	13,542	395,052	3,725	—	398,777
At September 30, 2000 (Thousands)										
Segment Assets	$1,233,639	$552,059	$1,088,066	$202,622	$47,121	$107,402	$3,230,909	$21,930	$(1,808)	$3,251,031

(1) Amount includes $1.2 million in a stock-for-asset swap.

GEOGRAPHIC INFORMATION

For the Year Ended September 30 (Thousands)	2002	2001	2000
Revenues from External Customers [1]:			
United States	**$1,293,239**	$1,887,958	$1,279,329
Czech Republic	**95,315**	97,910	104,736
Canada	**75,942**	73,968	28,351
	$1,464,496	$2,059,836	$1,412,416
At September 30 (Thousands)			
Long-Lived Assets:			
United States	**$2,624,810**	$2,645,429	$2,488,180
Czech Republic	**216,044**	187,961	183,274
Canada	**258,196**	257,939	248,937
	$3,099,050	$3,091,329	$2,920,391

(1) Revenue is based upon the country in which the sale originates.

NOTE J INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

The Company's unconsolidated subsidiaries consist of equity method investments in Seneca Energy II, LLC (Seneca Energy), Model City Energy, LLC (Model City), and Energy Systems North East, LLC (ESNE). The Company has 50% interests in each of these entities. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. ESNE generates electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. ESNE sells its electricity into the New York power grid.

In June 2002, the Company wrote off its 33-1/3% equity method investment in Independence, a partnership that had proposed to construct and operate a 400-mile pipeline to transport natural gas from Defiance, Ohio to Leidy, Pennsylvania. In June 2002, Independence submitted a motion to FERC requesting that FERC vacate the certificate issued to Independence to construct, own and operate the pipeline. Independence took this action because it had been unable to obtain sufficient customer contracts to proceed with the project. In connection with this filing, the Company wrote off its $15.2 million investment in Independence. FERC formally vacated the certificate in an order issued in July 2002.

A summary of the Company's investments in unconsolidated subsidiaries at September 30, 2002 and 2001 is as follows:

At September 30 (Thousands)	2002	2001
ESNE	**$12,522**	$12,950
Independence	**—**	14,632
Seneca Energy	**3,625**	3,735
Model City	**606**	451
	$16,753	$31,768

NOTE K STOCK ACQUISITIONS

In June 2001, the Company acquired the outstanding shares of Player Petroleum Corporation (Player), an oil and gas exploration and development company, with operations based primarily in the Province of Alberta, Canada. The cost of acquiring the outstanding shares of Player was approximately $90.6 million and the acquisition was accounted for in accordance with the purchase method. Player's results of operations were incorporated into the Company's consolidated financial statements for the period subsequent to the completion of the acquisition on June 30, 2001.

In June 2000, the Company acquired the outstanding shares of Tri Link Resources, Ltd. (Tri Link), a Calgary, Alberta-based oil and gas exploration and production company. The cost of acquiring the outstanding shares of Tri Link was approximately $123.8 million and the acquisition was accounted for in accordance with the purchase method. Tri Link's results of operations were incorporated into the Company's consolidated financial statements for the period subsequent to the completion of the acquisition on June 15, 2000.

Details of the stock acquisitions made by the Company during 2001 and 2000 are as follows:

Year Ended September 30 (Millions)	2001	2000
Assets acquired	$175.1	$259.9
Liabilities assumed	(84.5)	(136.1)
Cash paid	$90.6	$123.8

NOTE L QUARTERLY FINANCIAL DATA (UNAUDITED)

In the opinion of management, the following quarterly information includes all adjustments necessary for a fair statement of the results of operations for such periods. Per common share amounts are calculated using the weighted average number of shares outstanding during each quarter. The total of all quarters may differ from the per common share amounts shown on the Consolidated Statement of Income. Those per common share amounts are based on the weighted average number of shares outstanding for the entire fiscal year. Because of the seasonal nature of the Company's heating business, there are substantial variations in operations reported on a quarterly basis.

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) Available for Common Stock	Earnings (Loss) Per Common Share Basic	Earnings (Loss) Per Common Share Diluted
2002	*(Thousands, except per common share amounts)*				
12/31/2001	**$392,327**	**$58,798**	**$33,207**	**$0.42**	**$0.41**
3/31/2002	**$477,436**	**$89,328**	**$61,924**	**$0.78**	**$0.77**
6/30/2002	**$350,123**	**$57,357**	**$17,676**[1]	**$0.22**	**$0.22**
9/30/2002	**$244,610**	**$26,507**	**$ 4,875**	**$0.06**	**$0.06**
2001	*(Thousands, except per common share amounts)*				
12/31/2000	$552,212	$ 77,335	$ 52,984[2]	$ 0.67	$ 0.66
3/31/2001	$864,715	$103,572	$ 75,275[3]	$ 0.95	$ 0.94
6/30/2001	$393,007	$ 60,212	$ 36,618	$ 0.46	$ 0.45
9/30/2001	$249,902	$ (79,566)	$(99,378)[4]	$(1.25)	$(1.24)

(1) Includes expense of $9.9 million related to the impairment of investment in partnership.
(2) Includes expense of $7.5 million related to Stock Appreciation Rights (SARs), expense of $1.2 million related to early retirement offers and income of $2.6 million related to the termination of a long-term transportation contract.
(3) Includes income of $9.7 million related to SARs and expense of $4.2 million related to early retirement offers.
(4) Includes income of $5.3 million related to SARs and expense of $104.0 million related to the impairment of oil and gas assets.

NOTE M MARKET FOR COMMON STOCK AND RELATED SHAREHOLDER MATTERS (UNAUDITED)

At September 30, 2002, there were 20,004 holders of Company common stock. The common stock is listed and traded on the New York Stock Exchange. Information related to restrictions on the payment of dividends can be found in Note D - Capitalization. The quarterly price ranges and quarterly dividends declared for the fiscal years ended September 30, 2002 and 2001, are shown below:

Quarter Ended	Price Range High	Price Range Low	Dividends Declared
2002			
12/31/2001	**$24.95**	**$21.95**	**$.2525**
3/31/2002	**$25.70**	**$22.00**	**$.2525**
6/30/2002	**$24.98**	**$21.38**	**$.260**
9/30/2002	**$22.84**	**$15.61**	**$.260**
2001			
12/31/2000	$32.25	$25.57	$.240
3/31/2001	$31.60	$25.01	$.240
6/30/2001	$28.99	$25.90	$.2525
9/30/2001	$26.38	$21.96	$.2525

NOTE N SUPPLEMENTARY INFORMATION FOR OIL AND GAS PRODUCING ACTIVITIES

The following supplementary information is presented in accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," and related SEC accounting rules. All monetary amounts are expressed in U.S. dollars.

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

At September 30 (Thousands)	2002	2001
Proved Properties	$1,779,962	$1,586,889
Unproved Properties	50,925	152,326
	1,830,887	1,739,215
Less - Accumulated Depreciation, Depletion and Amortization	776,477	675,256
	$1,054,410	$1,063,959

Costs related to unproved properties are excluded from amortization as they represent unevaluated properties that require additional drilling to determine the existence of oil and gas reserves. Following is a summary of such costs excluded from amortization at September 30, 2002:

	Total as of September 30,	Year Costs Incurred			
(Thousands)	2002	2002	2001	2000	Prior
Acquisition Costs	$50,925	$21,170	$7,831	$10,895	$11,029

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Year Ended September 30 (Thousands)	2002	2001	2000
United States			
Property Acquisition Costs:			
Proved	$9,316	$1,713	$2,848
Unproved	698	15,296	19,066
Exploration Costs	25,583	42,338	50,163
Development Costs	51,792	88,987	72,039
	87,389	148,334	144,116
Canada			
Property Acquisition Costs:			
Proved	(536)	115,643	159,268
Unproved	2,804	2,612	77,198
Exploration Costs	8,779	8,523	573
Development Costs	15,332	36,554	11,013
	26,379	163,332	248,052
Total			
Property Acquisition Costs: (1)			
Proved	8,780	117,356	162,116
Unproved	3,502	17,908	96,264
Exploration Costs	34,362	50,861	50,736
Development Costs	67,124	125,541	83,052
	$113,768	$311,666	$392,168

(1) Total proved and unproved property acquisition costs for 2001 of $135.3 million include $107.6 million related to the Player acquisition. Total proved and unproved property acquisition costs for 2000 of $258.4 million include $236.5 million related to the Tri Link acquisition.

RESULTS OF OPERATIONS FOR PRODUCING ACTIVITIES

Year Ended September 30 (Thousands, Except Per Mcfe Amounts)	2002	2001	2000
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $43, $4 and $237, respectively)	$104,954	$216,729	$137,336
Oil, Condensate and Other Liquids	101,549	121,973	107,645
Total Operating Revenues [1]	206,503	338,702	244,981
Production/Lifting Costs	42,956	37,068	33,979
Depreciation, Depletion and Amortization ($1.25, $1.13 and $0.97 per Mcfe of production)	80,142	76,686	64,624
Income Tax Expense	30,253	83,649	52,656
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	53,152	141,299	93,722
Canada			
Operating Revenues:			
Natural Gas	14,621	4,379	485
Oil, Condensate and Other Liquids	56,511	74,349	26,320
Total Operating Revenues [1]	71,132	78,728	26,805
Production/Lifting Costs	30,109	27,089	7,858
Depreciation, Depletion and Amortization ($0.93, $0.93 and $0.77 per Mcfe of production)	21,707	18,719	4,321
Impairment of Oil and Gas Producing Properties [2]	—	180,781	—
Income Tax Expense (Benefit)	4,672	(63,795)	6,121
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	14,644	(84,066)	8,505
Total			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $43, $4 and $237, respectively)	119,575	221,108	137,821
Oil, Condensate and Other Liquids	158,060	196,322	133,965
Total Operating Revenues [1]	277,635	417,430	271,786
Production/Lifting Costs	73,065	64,157	41,837
Depreciation, Depletion and Amortization ($1.16, $1.08 and $0.95 per Mcfe of production)	101,849	95,405	68,945
Impairment of Oil and Gas Producing Properties [2]	—	180,781	—
Income Tax Expense	34,925	19,854	58,777
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$67,796	$57,233	$102,227

(1) Exclusive of hedging gains and losses. See further discussion in Note F - Financial Instruments
(2) See discussion of impairment in Note A - Summary of Significant Accounting Policies

Reserve Quantity Information (unaudited)

The Company's proved oil and gas reserves are located in the United States and Canada. The estimated quantities of proved reserves disclosed in the table below are based upon estimates by qualified Company geologists and engineers and are audited by independent petroleum engineers. Such estimates are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

	Gas MMcf			Oil Mbbl		
	U.S.	Canada	Total	U.S.	Canada	Total
Proved Developed and Undeveloped Reserves:						
September 30, 1999	320,792	—	320,792	75,819	—	75,819
Extensions and Discoveries	34,641	—	34,641	2,167	1,765	3,932
Revisions of Previous Estimates	(8,001)	—	(8,001)	4,000	—	4,000
Production	(41,478)	(192)	(41,670)	(4,248)	(899)	(5,147)
Sales of Minerals in Place	(7,444)	—	(7,444)	(227)	—	(227)
Purchases of Minerals in Place and Other	—	3,349	3,349	—	41,320	41,320
September 30, 2000	298,510	3,157	301,667	77,511	42,186	119,697
Extensions and Discoveries	35,960	15,681	51,641	924	3,625	4,549
Revisions of Previous Estimates	(22,813)	(34)	(22,847)	1,737	(5,396)	(3,659)
Production	(39,188)	(1,816)	(41,004)	(4,796)	(3,061)	(7,857)
Sales of Minerals in Place	(6,066)	(280)	(6,346)	(685)	(80)	(765)
Purchases of Minerals in Place and Other	410	38,859	39,269	104	3,259	3,363
September 30, 2001	266,813	55,567	322,380	74,795	40,533	115,328
Extensions and Discoveries	**16,542**	**20,263**	**36,805**	**1,437**	**586**	**2,023**
Revisions of Previous Estimates	**(24,108)**	**(20,676)**	**(44,784)**	**916**	**(10,278)**	**(9,362)**
Production	**(35,067)**	**(6,387)**	**(41,454)**	**(4,828)**	**(2,834)**	**(7,662)**
Sales of Minerals in Place	**(14,726)**	**—**	**(14,726)**	**(200)**	**(410)**	**(610)**
Purchases of Minerals in Place and Other	**—**	**—**	**—**	**—**	**—**	**—**
September 30, 2002	**209,454**	**48,767**	**258,221**	**72,120**	**27,597**	**99,717**
Proved Developed Reserves:						
September 30, 1999	222,929	—	222,929	57,333	—	57,333
September 30, 2000	227,250	3,157	230,407	66,074	35,130	101,204
September 30, 2001	213,792	53,463	267,255	50,640	33,676	84,316
September 30, 2002	**192,833**	**39,253**	**232,086**	**46,940**	**24,100**	**71,040**

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (unaudited)

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company's oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, it is based on year-end prices and costs adjusted only for existing contractual changes, and it assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under the widely fluctuating political and economic conditions of today's world.

The standardized measure is intended instead to provide a somewhat better means for comparing the value of the Company's proved reserves at a given time with those of other oil- and gas-producing companies than is provided by a simple comparison of raw proved reserve quantities.

Year Ended September 30 (Thousands)	2002	2001	2000
United States			
Future Cash Inflows	**$2,764,556**	$2,127,601	$3,886,499
Less:			
Future Production Costs	**546,182**	602,479	600,243
Future Development Costs	**117,999**	121,240	179,565
Future Income Tax Expense at Applicable Statutory Rate	**653,347**	376,667	1,006,366
Future Net Cash Flows	**1,447,028**	1,027,215	2,100,325
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	**665,941**	421,865	859,950
Standardized Measure of Discounted Future Net Cash Flows	**781,087**	605,350	1,240,375
Canada			
Future Cash Inflows	**888,515**	890,381	1,083,598
Less:			
Future Production Costs	**413,006**	533,848	277,067
Future Development Costs	**25,398**	19,608	21,399
Future Income Tax Expense at Applicable Statutory Rate	**101,919**	76,191	286,148
Future Net Cash Flows	**348,192**	260,734	498,984
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	**103,097**	79,295	221,227
Standardized Measure of Discounted Future Net Cash Flows	**245,095**	181,439	277,757
Total			
Future Cash Inflows	**3,653,071**	3,017,982	4,970,097
Less:			
Future Production Costs	**959,188**	1,136,327	877,310
Future Development Costs	**143,397**	140,848	200,964
Future Income Tax Expense at Applicable Statutory Rate	**755,266**	452,858	1,292,514
Future Net Cash Flows	**1,795,220**	1,287,949	2,599,309
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	**769,038**	501,160	1,081,177
Standardized Measure of Discounted Future Net Cash Flows	**$1,026,182**	$786,789	$1,518,132

The principal sources of change in the standardized measure of discounted future net cash flows were as follows:

Year Ended September 30 (Thousands)	2002	2001	2000
United States			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	$605,350	$1,240,375	$707,259
Sales, Net of Production Costs	(163,548)	(301,634)	(211,002)
Net Changes in Prices, Net of Production Costs	441,085	(921,719)	795,408
Purchases of Minerals in Place	—	1,191	—
Sales of Minerals in Place	(27,197)	(17,552)	(11,914)
Extensions and Discoveries	42,970	52,062	186,818
Changes in Estimated Future Development Costs	(42,069)	(3,157)	(82,270)
Previously Estimated Development Costs Incurred	45,310	61,482	88,322
Net Change in Income Taxes at Applicable Statutory Rate	(126,263)	363,425	(292,371)
Revisions of Previous Quantity Estimates	(32,646)	(29,841)	20,736
Accretion of Discount and Other	38,095	160,718	39,389
Standardized Measure of Discounted			
Future Net Cash Flows at End of Year	781,087	605,350	1,240,375
Canada			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	181,439	277,757	—
Sales, Net of Production Costs	(41,023)	(51,638)	(18,948)
Net Changes in Prices, Net of Production Costs	111,148	(161,461)	—
Purchases of Minerals in Place	—	30,575	424,072
Sales of Minerals in Place	(3,084)	(761)	—
Extensions and Discoveries	29,813	39,752	2,979
Changes in Estimated Future Development Costs	18,151	(31,009)	—
Previously Estimated Development Costs Incurred	12,361	12,176	—
Net Change in Income Taxes at Applicable Statutory Rate	(6,910)	73,865	(150,057)
Revisions of Previous Quantity Estimates	(88,571)	(64,368)	—
Accretion of Discount and Other	31,771	56,551	19,711
Standardized Measure of Discounted Future			
Net Cash Flows at End of Year	245,095	181,439	277,757
Total			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	786,789	1,518,132	707,259
Sales, Net of Production Costs	(204,571)	(353,272)	(229,950)
Net Changes in Prices, Net of Production Costs	552,233	(1,083,180)	795,408
Purchases of Minerals in Place	—	31,766	424,072
Sales of Minerals in Place	(30,281)	(18,313)	(11,914)
Extensions and Discoveries	72,783	91,814	189,797
Changes in Estimated Future Development Costs	(23,918)	(34,166)	(82,270)
Previously Estimated Development Costs Incurred	57,671	73,658	88,322
Net Change in Income Taxes at Applicable Statutory Rate	(133,173)	437,290	(442,428)
Revisions of Previous Quantity Estimates	(121,217)	(94,209)	20,736
Accretion of Discount and Other	69,866	217,269	59,100
Standardized Measure of Discounted Future			
Net Cash Flows at End of Year	$1,026,182	$786,789	$1,518,132

Schedule II

VALUATION AND QUALIFYING ACCOUNTS

(Thousands) Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts [1]	Deductions [2]	Balance at End of Period
Year Ended September 30, 2002					
Reserve for Doubtful Accounts	**$18,521**	**$16,082**	**$2,834**	**$20,138**	**$17,299**
Year Ended September 30, 2001					
Reserve for Doubtful Accounts	$12,013	$17,445	$ —	$10,937	$18,521
Year Ended September 30, 2000					
Reserve for Doubtful Accounts	$7,842	$15,177	$ —	$11,006	$12,013

(1) Represents amounts reclassified from regulatory asset and regulatory liability accounts under various rate settlements.
(2) Amounts represent net accounts receivable written-off.

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

None

Part III

ITEM 10 DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item concerning the directors of the Company is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 20, 2003 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2002. The information concerning directors is set forth in the definitive Proxy Statement under the captions entitled "Nominees for Election as Directors for Three-Year Terms to Expire 2005," "Directors Whose Terms Expire in 2004," "Directors Whose Terms Expire in 2003," and "Compliance with Section 16(a) of the Securities Exchange Act of 1934" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 20, 2003 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2002. The information concerning executive compensation is set forth in the definitive Proxy Statement under the captions "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee" and the "Corporate Performance Graph," is incorporated herein by reference.

ITEM 12 SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

EQUITY COMPENSATION PLAN INFORMATION

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	14,629,504	$22.12	942,669
Equity compensation plans not approved by security holders	0	0	0
Total	14,629,504	$22.12	942,669

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 20, 2003 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2002. The information concerning security ownership of certain beneficial owners is set forth in the definitive Proxy Statement under the caption "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(b) Security Ownership of Management

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 20, 2003 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2002. The information concerning security ownership of management is set forth in the definitive Proxy Statement under the caption "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(c) Changes in Control

None

ITEM 13 CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 20, 2003 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2002. The information regarding certain relationships and related transactions is set forth in the definitive Proxy Statement under the caption "Compensation Committee Interlocks and Insider Participation" and is incorporated herein by reference.

Part IV

ITEM 14 CONTROLS AND PROCEDURES

The following information includes the evaluation of disclosure controls and procedures by the Company's Chief Executive Officer and Treasurer, along with any significant changes in internal controls of the Company.

Evaluation of disclosure controls and procedures

The term "disclosure controls and procedures" is defined in Rules 13a-14(c) and 15d-14(c) of the Securities Exchange Act of 1934 (Exchange Act). These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files under the Exchange Act is recorded, processed, summarized and reported within required time periods. The Company's Chief Executive Officer and Treasurer have evaluated the effectiveness of the Company's disclosure controls and procedures as of a date within 90 days before the filing of this Annual Report on Form 10-K (Evaluation Date), and, they have concluded that, as of the Evaluation Date, such controls and procedures were effective to accomplish those tasks.

Changes in internal controls

The Company maintains a system of internal accounting controls that are designed to provide reasonable assurance that the Company's transactions are properly authorized, the Company's assets are safeguarded against unauthorized or improper use, and the Company's transactions are properly recorded and reported to permit preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States. There were no significant changes in the Company's internal controls or in other factors that could significantly affect the Company's internal controls subsequent to the Evaluation Date, nor were there any significant deficiencies or material weaknesses in the Company's internal controls.

ITEM 15 EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. Financial Statements

Financial statements filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a) 2. Financial Statement Schedules

Financial statements schedules filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a) 3. Exhibits

Exhibit Number **Description of Exhibits**

3(i) Articles of Incorporation:

- Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)

3(ii) By-Laws:

- National Fuel Gas Company By-Laws as amended on December 13, 2001 (Exhibit 3.1, Form 10-K/A for fiscal year ended September 30, 2001, in File No. 1-3880)

(4) Instruments Defining the Rights of Security Holders, Including Indentures:

- Indenture, dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
- Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)
- Tenth Supplemental Indenture, dated as of February 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a), Form 8-K dated February 14, 1992 in File No. 1-3880)
- Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992 in File No. 1-3880)
- Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992 in File No. 1-3880)
- Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
- Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993 in File No. 1-3880)
- Fifteenth Supplemental Indenture, dated as of September 1, 1996, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- Indenture dated as of October 1, 1999, between the Company and The Bank of New York (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Officers Certificate Establishing Medium-Term Notes, dated October 14, 1999 (Exhibit 4.2, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amended and Restated Rights Agreement, dated as of April 30, 1999, between the Company and HSBC Bank USA (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 1999 in File No. 1-3880)
- Certificate of Adjustment, dated September 7, 2001, to the Amended and Restated Rights Agreement dated as of April 30, 1999, between the Company and HSBC Bank USA (Exhibit 4, Form 8-K dated September 7, 2001 in File No. 1-3880)
- Officers Certificate establishing 6.50% notes due 2022, dated September 18, 2002 (Exhibit 4, Form 8-K dated October 3, 2002 in File No. 1-3880)

(10) Material Contracts:

(ii) Contracts upon which the Company's business is substantially dependent:

10.1 Credit Agreement, dated as of September 30, 2002, among the Company, the Lenders Party Thereto and JP Morgan Chase Bank, as Administrative Agent

(iii) Compensatory plans for officers:

- Retirement and Consulting Agreement, dated September 5, 2001, between the Company and Bernard J. Kennedy (Exhibit 10(iii)(a), Form 8-K dated September 19, 2001 in File No. 1-3880)
- Pension Settlement Agreement, dated September 5, 2001, between the Company and Bernard J. Kennedy (Exhibit 10(iii)(b), Form 8-K dated September 19, 2001 in File No. 1-3880)
- Employment Agreement, dated September 17, 1981, between the Company and Bernard J. Kennedy (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1994 in File No. 1-3880)
- Tenth Amendment to Employment Agreement between the Company and Bernard J. Kennedy, effective September 1, 1999 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Agreement, dated August 1, 1986, between the Company and Joseph P. Pawlowski (Exhibit 10.1, Form 10-K for fiscal year ended September 30,1997 in File No. 1-3880)
- Agreement, dated August 1, 1986, between the Company and Gerald T. Wehrlin (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- Form of Employment Continuation and Noncompetition Agreement, dated as of December 11, 1998, among the Company, National Fuel Gas Distribution Corporation and each of Philip C. Ackerman, Anna Marie Cellino, Walter E. DeForest, Joseph P. Pawlowski, James D. Ramsdell, Dennis J. Seeley, David F. Smith, Ronald J. Tanski and Gerald T. Wehrlin (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880)
- Form of Employment Continuation and Noncompetition Agreement, dated as of December 11, 1998, among the Company, National Fuel Gas Supply Corporation and each of Bruce H. Hale and John R. Pustulka (Exhibit 10.2, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880)

- Form of Employment Continuation and Noncompetition Agreement, dated as of December 11, 1998, among the Company, Seneca Resources Corporation and James A. Beck (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880)
- National Fuel Gas Company 1983 Incentive Stock Option Plan, as amended and restated through February 18, 1993 (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 1993 in File No. 1-3880)
- National Fuel Gas Company 1984 Stock Plan, as amended and restated through February 18, 1993 (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 1993 in File No. 1-3880)
- Amendment to the National Fuel Gas Company 1984 Stock Plan, dated December 11, 1996 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- National Fuel Gas Company 1993 Award and Option Plan, dated February 18, 1993 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1993 in File No. 1-3880)
- Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated October 27, 1995 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
- Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 11, 1996 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 18, 1996 (Exhibit 10, Form 10-Q for the quarterly period ended December 31, 1996 in File No. 1-3880)
- National Fuel Gas Company 1993 Award and Option Plan, amended through June 14, 2001 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880)
- National Fuel Gas Company 1997 Award and Option Plan, amended through June 14, 2001 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880)
- National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1994 in File No. 1-3880)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 27, 1995 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
- National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
- Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999 in File No. 1-3880)
- National Fuel Gas Company Tophat Plan, effective March 20, 1997 (Exhibit 10, Form 10-Q for the quarterly period ended June 30, 1997 in File No. 1-3880)
- Amendment No. 1 to National Fuel Gas Company Tophat Plan, dated April 6, 1998 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
- Amendment No. 2 to National Fuel Gas Company Tophat Plan, dated December 10, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
- Death Benefits Agreement, dated August 28, 1991, between the Company and Bernard J. Kennedy (Exhibit 10-TT, Form 10-K for fiscal year ended September 30, 1991 in File No. 1-3880)
- Amendment to Death Benefit Agreement of August 28, 1991, between the Company and Bernard J. Kennedy, dated March 15, 1994 (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
- Amended Restated Split Dollar Insurance Agreement, effective June 15, 2000, among the Company, Bernard J. Kennedy, and Joseph B. Kennedy, as Trustee of the Trust under the Agreement dated January 9, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2000 in File No. 1-3880)
- Contingent Benefit Agreement, effective June 15, 2000, between the Company and Bernard J. Kennedy (Exhibit 10.2, Form 10-Q for the quarterly period ended June 30, 2000 in File No. 1-3880)
- Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and Joseph P. Pawlowski (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Joseph P. Pawlowski, dated March 23, 1999 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Second Amended and Restated Split Dollar Insurance Agreement dated June 15, 1999,between the Company and Gerald T. Wehrlin (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and Walter E. DeForest (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Walter E. DeForest, dated March 29, 1999 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and Dennis J. Seeley (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Dennis J. Seeley, dated March 29, 1999 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)

- • Split Dollar Insurance and Death Benefit Agreement dated September 15, 1997, between the Company and Bruce H. Hale (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- • Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and Bruce H. Hale, dated March 29, 1999 (Exhibit 10.12, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- • Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- • Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)

10.2 Split Dollar Insurance Insurance Agreement, dated March 6, 2001, between the Company and James A. Beck

- • National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
- • National Fuel Gas Company and Participating Subsidiaries 1996 Executive Retirement Plan Trust Agreement (II), dated May 10, 1996 (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- • Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- • Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
- • Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- • Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001, in File No. 1-3880)
- • Retirement Supplement Agreement, dated September 14, 2000, between the Company and Gerald T. Wehrlin (Exhibit 10.5, Form 10-K/A for fiscal year ended September 30, 2001 in File No.1-3880)
- • Retirement Supplement Agreement, dated January 11, 2002, between the Company and Joseph P. Pawlowski (Exhibit 10.6, Form 10-K/A for fiscal year ended September 30, 2001 in File No. 1-3880)
- • Administrative Rules with Respect to At Risk Awards under the 1993 Award and Option Plan (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- • Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan (Exhibit A, Definitive Proxy Statement, Schedule 14(A) filed January 10, 2002 in File No. 1-3880)
- • Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated, effective December 10, 1998 (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
- • Excerpts of Minutes from the National Fuel Gas Company Board of Directors Meeting of February 20, 1997 regarding the Retirement Benefits for Bernard J. Kennedy (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- • Excerpts of Minutes from the National Fuel Gas Company Board of Directors Meeting of March 20, 1997 regarding the Retainer Policy for Non-Employee Directors (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)

(12) Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 1998 through 2002

(21) Subsidiaries of the Registrant:
See Item 1 of Part I of this Annual Report on Form 10-K

(23) Consents of Experts:

23.1 Consent of Ralph E. Davis Associates, Inc. regarding Seneca Resources Corporation

23.2 Consent of Ralph E. Davis Associates, Inc. regarding National Fuel Exploration Corp.

23.3 Consent of Ralph E. Davis Associates, Inc. regarding Player Resources Ltd.

23.4 Consent of Independent Accountants

(99) Additional Exhibits:

99.1 Report of Ralph E. Davis Associates, Inc. regarding Seneca Resources Corporation

99.2 Report of Ralph E. Davis Associates, Inc. regarding National Fuel Exploration Corp.

99.3 Report of Ralph E. Davis Associates, Inc. regarding Player Resources Ltd.

99.4 Written statements of Chief Executive Officer and Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.5 Company Maps

• *Incorporated herein by reference as indicated.*

All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K.

(b) Reports on Form 8-K

A report on Form 8-K dated August 14, 2002 was filed on August 14, 2002, to report a sworn statement from the principal executive and financial officers, under Item 9, "Regulation FD Disclosure." Related exhibits were reported under Item 7, "Financial Statements and Exhibits."

A report on Form 8-K dated July 25, 2002 was filed on July 29, 2002, to report earnings for the quarter ended June 30, 2002, the participation in the drilling of a natural gas discovery and to address certain matters from the Company's public conference call, under Item 5, "Other Events." Related exhibits were reported under Item 7, "Financial Statements and Exhibits."

Signatures

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

National Fuel Gas Company
(Registrant)

By/s/ P. C. Ackerman

P. C. Ackerman
Chairman of the Board, President and Chief Executive Officer
Date: December 12, 2002

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

SIGNATURE / TITLE

/s/ P. C. Ackerman

P. C. Ackerman
Chairman of the Board, President, Chief Executive Officer and Director
Date: December 12, 2002

/s/ R. T. Brady

R. T. Brady
Director
Date: December 12, 2002

/s/ J. V. Glynn

J. V. Glynn
Director
Date: December 12, 2002

/s/ W. J. Hill

W. J. Hill
Director
Date: December 12, 2002

/s/ B. J. Kennedy

B. J. Kennedy
Director
Date: December 12, 2002

/s/ R.E. Kidder

R.E. Kidder
Director
Date: December 12, 2002

SIGNATURE / TITLE

/s/ B. S. Lee

B. S. Lee
Director
Date: December 12, 2002

/s/ E. T. Mann

E. T. Mann
Director
Date: December 12, 2002

/s/ G. L. Mazanec

G. L. Mazanec
Director
Date: December 12, 2002

/s/ J. F. Riordan

J. F. Riordan
Director
Date: December 12, 2002

/s/ J. P. Pawlowski

J. P. Pawlowski
Treasurer, Principal Financial Officer and Principal Accounting Officer
Date: December 12, 2002

Certification

I, Philip C. Ackerman, certify that:

1. I have reviewed this annual report on Form 10-K of National Fuel Gas Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: December 12, 2002

/s/ Philip C. Ackerman

Philip C. Ackerman
Chairman of the Board, President and
Chief Executive Officer

Certification

I, Joseph P. Pawlowski, certify that:

1. I have reviewed this annual report on Form 10-K of National Fuel Gas Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: December 12, 2002

/s/ Joseph P. Pawlowski

Joseph P. Pawlowski
Treasurer and Principal Financial Officer

Glossary

bbl barrel

Bcf Billion cubic feet

Bcf (or Mcf) Equivalent The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. National Fuel uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.

Board Foot A measure of lumber and/or timber equal to 12 inches in length by 12 inches in width by one inch in thickness.

Combined-Cycle Electric Generating Plant A power plant that produces electricity by use of a gas-fired turbine to turn an electric generator. Exhaust heat is used by a heat recovery steam generator, where steam is produced to turn a steam turbine, which then turns a second electric generator.

Degree Day A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.

Derivative A contract, as an option or futures contract, whose value depends on the value of the securities, commodities, etc. that form the basis of the contract.

Distributed Generation Any power generation technology (such as fuel cells, microturbines, engines, turbines, etc.) that provides electric power at a site closer to customers than a central generating station. A distributed generation unit can be connected directly to the end user, or to an electric utility's transmission or distribution system.

Dth Dekatherm-one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.

Farm-Out An interest in an oil or gas lease which is granted to a third party by the lease holder.

FERC Federal Energy Regulatory Commission

Firm Transportation and/or Storage The transportation and/or storage service that a supplier of such service is obligated by contract to provide.

Fuel Cell An electrochemical generator that produces electricity from a chemical reaction by combining oxygen and hydrogen (a component of natural gas).

Gathering System The pipes, pumps, auxiliary tanks (in the case of oil), and other equipment used to move oil or gas from the well site to the main pipeline for eventual delivery to the refinery or consumer, as the case may be. In the case of gas, the gathering system includes the processing plant (if any) in which the gas is prepared for the market.

Gigajoule One billion joules. A "joule" is a unit of energy.

Grid The layout of the electrical transmission system or a synchronized transmission network.

Heat-Recovery System A system used to recover the waste heat from distributed generation equipment and convert it to useful thermal energy in the form of steam, hot water or hot air for space heating and process heating applications.

Hedging A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes.

Horizontal Drilling An experimental natural gas production process whereby a well is drilled horizontally, rather than vertically, to penetrate a gas-bearing formation.

Hub Location where pipelines intersect enabling the trading, transportation, storage, exchange and lending of natural gas.

Interruptible Transportation and/or Storage The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service.

Kilowatt (kW) A unit of electrical power equal to one thousand watts.

Mbbl Thousand barrels

Mcf Thousand cubic feet

MDth Thousand dekatherms

Megawatt One million watts. A "watt" is a unit of electrical power.

Megawatt Hour A unit of electrical energy which equals one megawatt of power used for one hour.

Microturbine A small-scale gas turbine, typically producing less than 1,000 kilowatts (kW) of power. The technology employed by microturbines is the same as that of jet engines, using rotating power to drive electric generators that produce electricity.

MMcf Million cubic feet

MMcfe Million cubic feet equivalent (1 barrel of oil = 6 Mcf of gas)

NYMEX New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.

NYPSC State of New York Public Service Commission

Open Access Transportation The transportation of natural gas by a pipeline or utility upon request.

PaPUC Pennsylvania Public Utility Commission

Reserves Estimated volumes of oil, gas or other minerals that can be recovered from deposits in the earth with reasonable certainty.

Reserve-to-Production Ratio An estimate used to project the productive life of a field based upon the size of the field compared to the annual production capacity, expressed in years' supply.

Restructuring Generally referring to partial "deregulation" of the utility industry by statutory or regulatory process. Restructuring of federally-regulated pipelines separated (or "unbundled") gas commodity from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.

Spot Gas Purchases The purchase of natural gas on a short-term basis usually at a lower cost than long-term pipeline contracts.

Stranded Costs Costs associated with facilities or contracts that, because of restructuring, may not be directly recoverable from customers.

Transportation Gas The movement of gas for third parties through pipeline facilities for a fee.

Unbundled Service The separation of services, with rates charged that reflect the cost of the selected service.

Underground Storage The injection of large quantities of natural gas into underground rock formations for storage during periods of low market demand and withdrawal during periods of high market demand.

Weather Normalization A clause in utility rates which adjusts customer costs to reflect normal temperatures. If temperatures during the measured period are warmer than normal, customers receive a surcharge. If temperatures during the measured period are colder than normal, customers receive a credit.

Weighted Average Price A price computed by averaging together the cost of each unit.

Well Logging The process of recording, by various mechanical and electrical means, the rock formations penetrated by a well and data regarding their depth, thickness, porosity and contents.

Officers

National Fuel Gas Company

Philip C. Ackerman
Chairman of the Board, President and Chief Executive Officer

Joseph P. Pawlowski
Treasurer

Gerald T. Wehrlin
Controller

Anna Marie Cellino
Secretary

OFFICERS OF PRINCIPAL SUBSIDIARIES

National Fuel Gas Distribution Corporation

Philip C. Ackerman
Chairman of the Board

David F. Smith
President

Anna Marie Cellino
Senior Vice President and Secretary

Walter E. DeForest
Senior Vice President

Joseph P. Pawlowski
Senior Vice President and Treasurer

James D. Ramsdell
Senior Vice President

Dennis J. Seeley
Senior Vice President

Ronald J. Tanski
Senior Vice President and Controller

Carl M. Carlotti
Vice President

National Fuel Gas Supply Corporation

Philip C. Ackerman
Chairman of the Board

Dennis J. Seeley
President

Bruce H. Hale
Senior Vice President

John R. Pustulka
Senior Vice President

David F. Smith
Senior Vice President

Joseph P. Pawlowski
Treasurer and Secretary

Seneca Resources Corporation

Philip C. Ackerman
Chairman of the Board

James A. Beck
President

Barry L. McMahan
Senior Vice President

John F. McKnight
Vice President

Thomas L. Atkins
Treasurer

Donald P. Butler
Secretary

National Fuel Resources, Inc.

Gerald T. Wehrlin
President and Treasurer

Donna L. DeCarolis
Vice President and Secretary

Highland Forest Resources, Inc.

Philip C. Ackerman
Chairman of the Board

James A. Beck
President

Thomas L. Atkins
Treasurer

Donald P. Butler
Secretary

Horizon Energy Development, Inc.

Philip C. Ackerman
President

Bruce H. Hale
Vice President

Gerald T. Wehrlin
Vice President

Ronald J. Tanski
Treasurer and Secretary

Directors

Philip C. Ackerman [6]
Chairman of the Board of Directors of the Company, Chief Executive Officer since October 2001, and President since July 1999. Chairman of the Board and President of certain subsidiaries of the Company. Board member since 1994.

Robert T. Brady [3, 5, 8]
Chairman, President and Chief Executive Officer of Moog Inc. Board member since 1995. Director of Acme Electric Corporation, Astronics Corporation, M&T Bank Corporation, M&T Bank and Seneca Foods Corporation.

James V. Glynn [1, 7]
Chairman and Chief Executive Officer since November 2001 of Maid of the Mist Corporation and former President from 1971 to November 2001. Board member since 1997. Director of M&T Bank Corporation, M&T Bank, and Chairman Emeritus of Niagara University Board of Trustees.

William J. Hill [1, 5, 7]
Retired President of National Fuel Gas Distribution Corporation. Board member since 1995. Director of National Fuel Gas Distribution Corporation and Reed Manufacturing Company.

Bernard J. Kennedy [7]
Chairman of the Board of Directors of the Company from March 1989 to January 2002, Chief Executive Officer from August 1988 to October 2001, and President from January 1987 to July 1999. Chairman of the Board of Associated Electric & Gas Insurance Services Limited.

Rolland E. Kidder [1]
Executive Director of the Robert H. Jackson Center in Jamestown, N.Y. Board member since September 2002. Former Chairman and President of Kidder Exploration, Inc. Former Trustee of the New York Power Authority.

Bernard S. Lee, PhD [2]
Former President of the Institute of Gas Technology. Board member since 1994. Director of NUI Corporation and Peerless Manufacturing Company.

Eugene T. Mann [3, 5, 7]
Retired Executive Vice President of Fleet Boston Financial Group. Board member since 1993.

George L. Mazanec [4, 5]
Former Vice Chairman of PanEnergy Corporation (now part of Duke Energy Corporation). Board member since 1996. Director of the Northern Trust Bank of Texas, NA, and Associated Electric & Gas Insurance Services Limited. Former Chairman of the Management Committee of Maritimes & Northeast Pipeline, L.L.C.

John F. Riordan [1, 3]
President and Chief Executive Officer of the Gas Technology Institute since April 2000. Board member since July 2000. Director of Nicor Inc., Niagara University, and the Oral and Maxillofacial Surgery Foundation.

1 Member of Audit Committee
2 Chairman, Audit Committee
3 Member of Compensation Committee
4 Chairman, Compensation Committee
5 Member of Executive Committee
6 Chairman, Executive Committee
7 Member of Nominating/Corporate Governance Committee
8 Chairman, Nominating/Corporate Governance Committee

Investor Information

Common Stock Transfer Agent and Registrar*

Computershare Investor Services, LLC
P.O. Box A3504
Chicago, IL 60690-3504
Tel. (800) 648-8166
Web site at:
http://www-us.computershare.com/investors
E-mail: web.queries@computershare.com

** Change-of-address notices and inquiries about dividends should be sent to the Transfer Agent at address shown.*

Stock Exchange Listing

New York Stock Exchange (Stock Symbol: NFG)

National Fuel Direct Stock Purchase and Dividend Reinvestment Plan

National Fuel offers a simple, cost-effective method for purchasing shares of National Fuel stock.

A Prospectus, which includes details of the Plan, can be obtained by calling, writing or e-mailing Computershare Investor Services, LLC, the agent for the Plan, at:

Computershare Investor Services, LLC
P.O. Box A3309
Chicago, IL 60690-9994
Tel. (800) 648-8166
E-mail: web.queries@computershare.com

Trustee for Debentures

The Bank of New York
101 Barclay Street
New York, NY 10286

Independent Accountants

PricewaterhouseCoopers LLP
3600 HSBC Center
Buffalo, NY 14203

Annual Meeting

The Annual Meeting of Shareholders will be held at 10 a.m. (local time) on Thursday, February 20, 2003, at The Houstonian Hotel, 111 North Post Oak Lane, Houston, Texas 77024. Formal notice of the meeting, proxy statement and proxy will be mailed to shareholders of record as of December 23, 2002.

Investor Relations

Investors or financial analysts desiring information should contact:

Joseph P. Pawlowski
Treasurer
Tel. (716) 857-6904

Margaret M. Suto
Director, Investor Relations
Tel. (716) 857-6987
E-mail: sutom@natfuel.com

National Fuel Gas Company
10 Lafayette Square
Buffalo, NY 14203

Additional Shareholder Reports

Additional copies of this report and the Financial and Statistical Supplement to the 2002 Annual Report can be obtained without charge by writing to or calling:

Anna Marie Cellino
Corporate Secretary

National Fuel Gas Company
10 Lafayette Square
Buffalo, NY 14203
Tel. (716) 857-7858

This Annual Report and the statements contained herein are submitted for the general information of shareholders and employees of the Company and are not intended to induce any sale or purchase of securities or to be used in connection therewith.

For up-to-date information, we have two sources for your use. You may call **1-800-334-2188** *at any time to receive National Fuel's current stock price and trade volume or to hear the latest news releases. You may also have news releases faxed or mailed to you. National Fuel has an Internet Web site at* **http://www.nationalfuelgas.com.** *You may sign up there to automatically receive news releases by e-mail. Simply go to the* **News & Info** *section and subscribe.*

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100

national Fuel

Since 1902

National Fuel Gas Company

10 Lafayette Square

Buffalo, NY 14203

(716) 857-7000

www.nationalfuelgas.com