National Fuel Gas Company

2003 ANNUAL REPORT

AND FORM 10-K

DEVELOPING RESOURCES DELIVERING ENERGY SERVING CUSTOMERS

CORPORATE PROFILE

National Fuel Gas Company, incorporated in 1902, is a diversified energy company with its headquarters in Williamsville, New York. The Company's $3.6 billion in assets is distributed among six principal business segments: Pipeline and Storage, Utility, Exploration and Production, 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 101-year tradition of delivering service and value.

CONTENTS

Highlights **1**
At a Glance **2**
Letter to Shareholders **5**
Officers and Directors **16**
Form 10-K **17**
Glossary **108**
Investor Information **109**

Pipeline and Storage *National Fuel Gas Supply Corporation* and *Empire State Pipeline* provide natural gas transportation and storage services to affiliated and nonaffiliated companies through an integrated system of 3,040 miles of pipeline and 32 underground natural gas storage fields (including four storage fields co-owned with nonaffiliated companies). This system is located within an area bounded by the Canadian border at the Niagara River, southwestern Pennsylvania and central New York just north of Syracuse.

Utility *National Fuel Gas Distribution Corporation* sells or transports natural gas to over 733,000 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.

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, 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.

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.

Highlights

Year Ended September 30	2003	2002	2001	2000	1999
Operating Revenues *(Thousands)*	**$2,035,471**	$1,464,496	$2,059,836	$1,412,416	$1,254,402
Net Income Available for					
Common Stock *(Thousands)*	**$ 178,944** [1]	$ 117,682 [2]	$ 65,499 [3]	$ 127,207	$ 115,037
Return on Average Common Equity [4]	**15.7%**	11.2%	6.4%	13.0%	12.6%
Per Common Share					
Basic Earnings	**$ 2.21** [5]	$ 1.47	$ 0.83	$ 1.63	$ 1.49
Diluted Earnings	**$ 2.20** [5]	$ 1.46	$ 0.82	$ 1.61	$ 1.47
Dividends Paid	**$ 1.05**	$ 1.02	$ 0.97	$ 0.94	$ 0.91
Dividend Rate at Year-End	**$ 1.08**	$ 1.04	$ 1.01	$ 0.96	$ 0.93
Book Value at Year-End	**$13.97**	$12.54	$12.63	$12.55	$12.09
Common Shares Outstanding at Year-End	**81,438,290**	80,264,734	79,406,105	78,659,606	77,674,998
Weighted Average Common Shares Outstanding					
Basic	**80,808,794**	79,821,430	79,053,444	78,233,842	77,327,962
Diluted	**81,357,896**	80,534,453	80,361,258	79,166,200	78,083,456
Average Common Shares Traded Daily	**221,021**	180,675	222,308	161,271	121,327
Common Stock Price					
High	**$27.51**	$25.70	$32.25	$29.41	$25.00
Low	**$17.95**	$15.61	$21.96	$19.69	$18.75
Close	**$22.85**	$19.87	$23.03	$28.03	$23.59
Net Cash Provided by Operating Activities *(Thousands)*	**$ 326,837**	$ 345,550	$ 414,027	$ 238,246	$ 267,504
Total Assets *(Thousands)*	**$3,727,915**	$3,401,309	$3,445,231	$3,251,031	$2,842,586
Expenditures for Long-Lived Assets *(Thousands)*	**$ 381,440**	$ 232,904	$ 385,103	$ 398,777	$ 265,527
Volume Information					
Utility Throughput-MMcf					
Gas Sales	**112,162**	101,444	104,186	97,617	101,675
Gas Transportation	**64,232**	61,909	66,283	71,862	64,086
Pipeline & Storage Throughput-MMcf					
Gas Transportation	**350,929**	297,822	321,555	313,548	308,303
Production Volumes					
Gas-MMcf	**33,805**	41,454	41,004	41,670	37,166
Oil-Mbbl	**6,737**	7,662	7,857	5,147	4,016
Total-MMcfe	**74,227**	87,426	88,146	72,552	61,262
Proved Reserves					
Gas-MMcf	**251,117**	258,221	322,380	301,667	320,792
Oil-Mbbl	**69,764**	99,717	115,328	119,697	75,819
Total-MMcfe	**669,700**	856,523	1,014,348	1,019,849	775,706
Energy Marketing Volumes-MMcf					
Gas	**45,325**	33,042	36,753	35,465	34,454
International Sales Volumes					
Heating (Gigajoules)	**8,714,806**	8,689,887	9,978,118	10,222,024	10,047,042
Electricity (Megawatt hours)	**973,968**	972,832	1,019,901	1,147,303	1,138,980
Average Number of Utility Retail Customers	**680,007**	680,489	678,357	656,792	691,080
Average Number of Utility Transportation Customers	**53,381**	51,729	54,140	78,610	41,515
Number of Employees at September 30 [6]	**3,037**	3,177	3,235	3,597	3,807

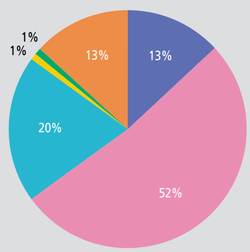
(1) Includes gain on sale of timber properties of $102.2 million, loss on sale of oil and gas assets of ($39.6) million, impairment of oil and gas assets of ($28.9) million and cumulative effect of changes in accounting of ($8.9) million.
(2) Includes impairment of investment in a partnership of ($9.9) million.
(3) Includes impairment of oil and gas of ($104.0) million.
(4) Calculated using Total Common Shareholder Equity Before Items of Other Comprehensive Income (Loss).
(5) Per common share amounts include an ($0.11) reduction to both basic and diluted earnings per share related to the cumulative effect of changes in accounting.
(6) Includes 897, 944, 991, 1,201 and 1,406 international employees at September 30, 2003, 2002, 2001, 2000 and 1999, respectively.

2003 At a Glance

Diluted Earnings Per Share
Dollars Per Share

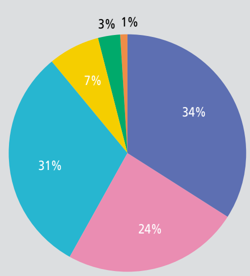
(1) Includes cumulative effect of changes in accounting of $(0.11) diluted.

Expenditures for Long-Lived Assets
by Segment



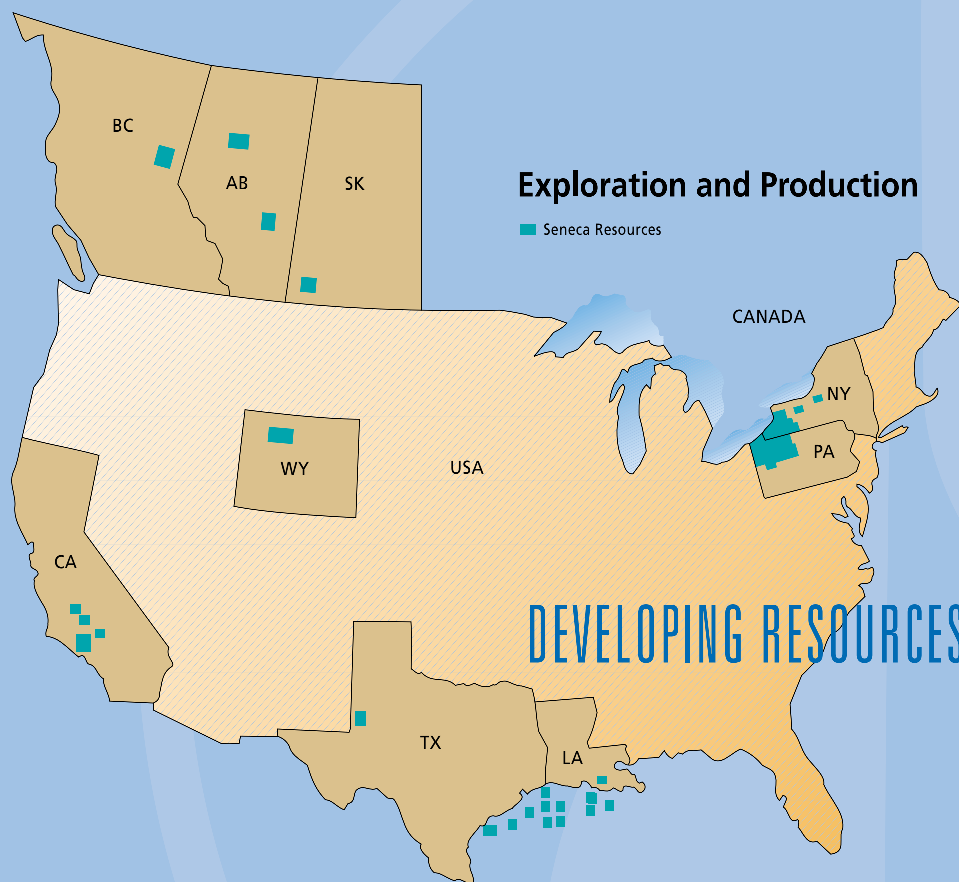
Total: $381.4 million

Net Plant
by Segment



Total: $3.0 billion

- Utility
- Pipeline and Storage
- Exploration and Production
- International
- Timber
- All Other and Corporate

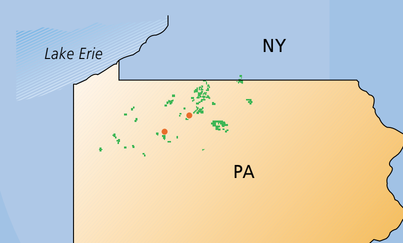


IN 2003 **EXPLORATION AND PRODUCTION**

- Weighted average prices of natural gas and oil after hedging rose from $3.58 to $4.47 per Mcf and from $19.94 to $21.84 per barrel, respectively, offsetting a decrease in total production of 15%.
- Sale of Southeast Saskatchewan properties completed in September with a $39.6 million after-tax loss, plus $28.9 million after-tax impairments of Canadian oil and gas assets, led to net loss of $31.9 million.

TIMBER

- Sale of approximately 70,000 acres of timber boosted earnings by $102.2 million to $112.5 million.
- Production increased 6.7% to 34.0 million board feet.



Timber

- Seneca Acreage
- Sawmills

OUTLOOK * **EXPLORATION AND PRODUCTION**

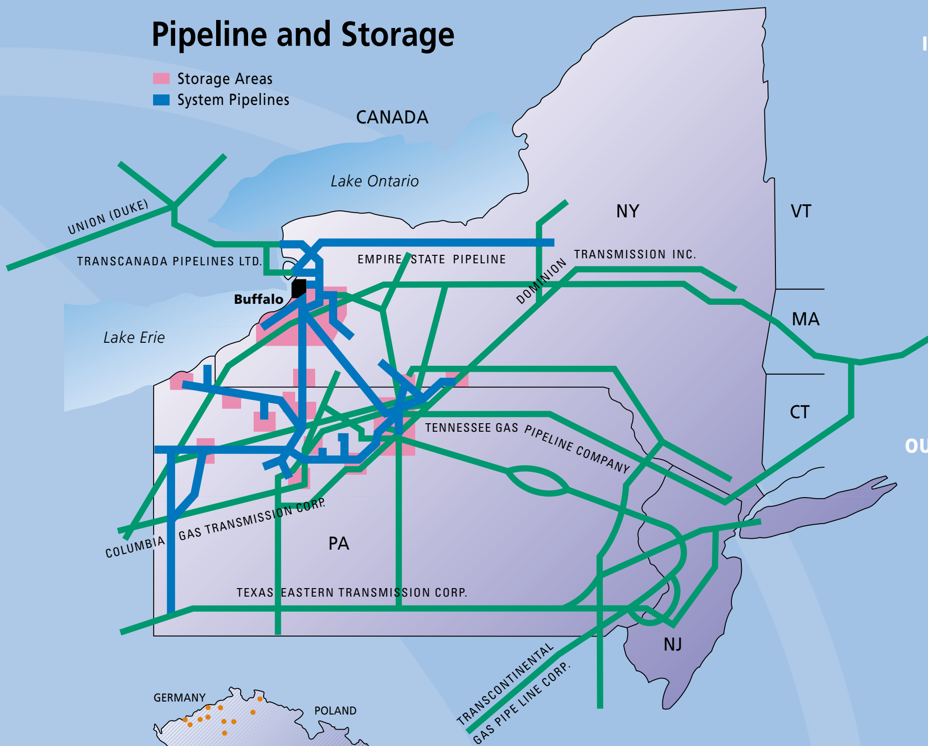
- Production goal of 57-62 Bcf equivalent to emphasize natural gas drilling and production.
- Capital budget of $90 million planned to focus on areas of proven success, living within cash flow, and controlling production costs..

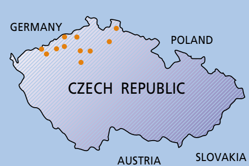
TIMBER

- Harvesting expected to be lower with remaining timber holdings of 87,000 acres.

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

Pipeline and Storage





International

Horizon Energy

IN 2003 **PIPELINE AND STORAGE**

- Net income of $45.2 million contributed over 25% of total Company earnings.
- Completed acquisition of Empire State Pipeline for $181 million plus $58 million of project debt.

INTERNATIONAL

- Net loss of $9.6 million includes an $8.3 million impairment from adoption of accounting rule disallowing amortization of goodwill expense; absent the impairment, earnings improved $3.1 million to a loss of $1.4 million.

OTHER

- Completed acquisition of Toro Partners' interests in landfill gas pipelines for $48 million.

OUTLOOK * **PIPELINE AND STORAGE**

- Strategic value from Empire State Pipeline will become apparent as a result of owning it for a full year and working diligently to increase its throughput.
- As nation's energy needs and concerns for available pipeline and storage capacity grow, greater opportunities will arise from owning and operating pipeline assets, where we have a proven record of excellent results.

INTERNATIONAL

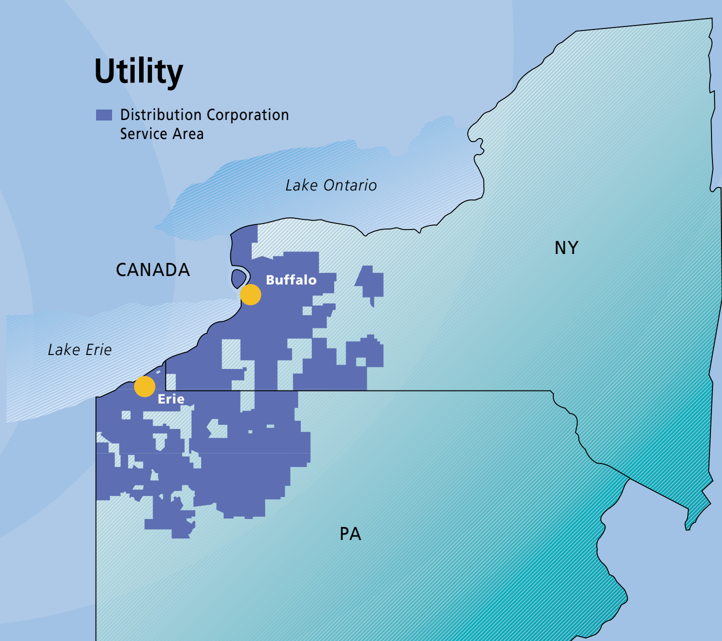
- Continue to evaluate additional prospects throughout Eastern and Central Europe.

OTHER

- Broaden scope of landfill gas and related environmentally friendly projects.

DELIVERING ENERGY SERVING CUSTOMERS

Utility



Energy Marketing

National Fuel Resources

IN 2003 **UTILITY**

- Net income of $56.8 million provided nearly 32% of total Company earnings.
- Successfully negotiated one-year rate settlement agreement in New York, which maintains current base rates and includes a 50/50 sharing mechanism for earnings in excess of targeted 11.0% return on equity.
- Pennsylvania rate case agreement includes first base rate increase since 1995 of $3.5 million and deferral of pension funding.

ENERGY MARKETING

- Achieved second-best earnings performance with net income of $5.9 million or $0.07 per diluted share.

OUTLOOK * **UTILITY**

- Promote decentralized natural-gas powered electric generation (distributed generation) throughout the service territory as a secure, reliable and effective alternative for large use customers to meet their electric power needs.
- Maintain excellent levels of operational safety and customer service while continuing to contain costs.

ENERGY MARKETING

- Continue focus on core markets, margin protection and risk management efforts.

During the first quarter of fiscal 2004, National Fuel completed the relocation of its corporate headquarters from Buffalo, N.Y. to suburban Williamsville. The Company decided that a more modern two-story building would enhance communication and efficiencies among its workforce. This nearly new building, which was designed as a corporate headquarters, does exactly that.

TO OUR SHAREHOLDERS:

Fiscal 2003 was a year of such extraordinary progress for your Company that our record earnings of $2.20 per share, a 51% increase over last year's earnings of $1.46 per share, will prove to be of secondary importance. Two acquisitions and two divestitures permitted us to achieve record earnings, strengthen our balance sheet without an equity issue, and rebalance our portfolio, with a greater emphasis on pipeline assets where we have a proven record of excellent results.

First, in February we acquired the Empire State Pipeline for approximately $181 million plus about $58 million of project debt. For several years, we have been alert for appropriate opportunities to expand our regulated businesses to match the rapid growth of assets in our non-regulated segments, and Empire provided our chance. This acquisition also offers important advantages in the long run by giving us access to new markets to the east and building on one of our core strengths – the delivery of natural gas.*

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

Second, the acquisition of the Empire pipeline, which was initially financed through short-term debt, was permanently financed through the sale of about one-half of our timber assets. We used the proceeds from that sale, about $186 million, to eliminate the short-term debt thus improving our capital structure without the dilutive effect of issuing additional stock at an unfavorable market price. With our equity component now at 43%, we are on our way to attaining a 50/50 debt-equity ratio.* We are mindful that there is a greater focus on the degree of debt in corporate finance, and reducing our debt will enhance our creditworthiness and better prepare us to take advantage of other acquisition opportunities as they arise.*

Third, in June we acquired several landfill gas pipeline systems from Toro Partners, L.P. for $48 million. We are pleased with our experience with our other landfill gas projects, where the gas is used to generate electricity. This acquisition builds on that favorable result, increases net income, and further utilizes another of our core competencies – operating pipeline systems.*

Finally, in September we sold our oil and gas properties in Southeast Saskatchewan, Canada. The oil properties simply did not develop as we had thought they would when we acquired them. We decided to sell them and focus our Canadian exploration efforts on natural gas. As a result of the sale we paid down $76 million of short-term debt and further strengthened our balance sheet.

Our record earnings were driven by increased net income from our Utility and Pipeline and Storage segments, and particularly by a $102.2 million after-tax gain on the timber sale. This gain was partially offset by a $39.6 million after-tax loss on the Southeast Saskatchewan sale.

In recognition of the Company's progress and prospects, in 2003 the Board of Directors increased the dividend for the 33rd consecutive year, and 2003 marked our 101st year of dividends. Additionally, the market price per share of Company stock rose from last year's close of $19.87 per share up to $27.51 per share in July, to close at $22.85 on September 30th. More recently, the market price of your Company stock increased to $24.67 per share.

Over the past several months, natural gas prices have skyrocketed, from less than $5.00 to nearly $7.00 per thousand cubic feet, and as I write this letter, prices remain over $6.00. In any but the most shortsighted of views, this is not good for National Fuel. Yes, we will have some increased profits from our producing segment as a result of these increases, but higher prices inevitably reduce demand thereby reducing our opportunities in our Utility and Pipeline and Storage businesses. Indeed, even in exploration and production, highly volatile prices increase the risks associated with new investments and make planning more difficult.

The key to the long-term prosperity of the gas industry, and thus to National Fuel, will be abundant supplies of predictably and reasonably priced natural gas.*

While the National Energy Bill has yet to be passed, even if it were, it would be only a step in the development of a national energy policy, and it would not achieve the gas supplies we need.* It is no secret that vast reserves of gas exist in the lower 48 states, yet it is not widely understood that a great percentage of those reserves are inaccessible because of the many and extensive areas where drilling is off-limits. One of the great frustrations is that somehow opening lands to drilling is thought of as a give-away to the oil and natural gas industries when, in fact, it would be of direct benefit to the consumer through lower prices, and to the environment by making available to meet our needs more clean burning natural gas to take the place of coal or oil.

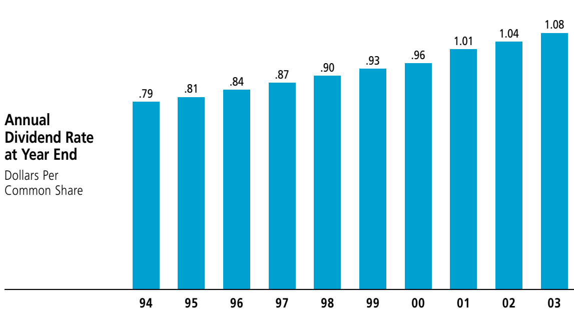
This year provided us with many opportunities to position your Company so that we may continue to provide the excellent results you've come to expect. Change can be a challenge, but our recent experiences have underscored our long-held confidence in the historic strengths and core capabilities of your Company. We've said this before, and it bears repeating: natural gas is the best fuel we have, and ours is a fundamental service – we provide heat and energy for homes and businesses. The details of how we do this follow.

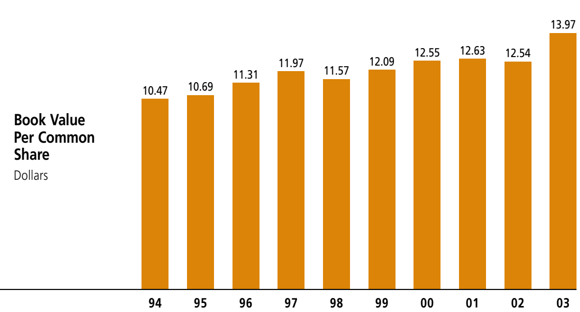
Our **Pipeline and Storage** segment's earnings in 2003 of $45.2 million represent an increase of $15.5 million from 2002. Last year's earnings reflected a write-down of $9.9 million for the Independence Pipeline Project, and this year's earnings from transportation, storage and unbundled pipeline sales increased by $4.2 million.

In February 2003, we expanded this segment with a strategic investment, the Empire State Pipeline, which provides new growth and extends our system to new markets. This 157-mile long, 24-inch pipeline can transport more than 500 million cubic feet of natural gas per day from the Canadian border near Buffalo eastward to central New York. Most of its capacity is under long-term contracts. As our nation's energy needs continue to grow, so do concerns about available pipeline capacity, storage capacity and storage deliverability. The Empire pipeline's capacity is economically expandable by adding compression or by connecting to nearby storages, local utilities and other pipelines.* We expect a greater contribution from Empire in 2004 as a result of owning it for a full year, and we are working very diligently to create opportunities to increase its throughput both this winter and in the longer term.*

There are a number of facilities proposed to bring natural gas to the Northeast from Canada, the Rocky Mountains and the mid-continent, including our Northwinds Pipeline project. At an estimated cost of $350-$400 million, Northwinds would originate in Kirkwall, Ontario, enter the United States near Buffalo, and follow a southerly route to the Ellisburg-Leidy hub in Pennsylvania.*

Over the last decade, local distribution companies (LDCs) were pressured by state regulatory commissions to stop making long-term contracts for transportation and storage as regulators anticipated the development of a robust competitive gas market at the retail level. As a result of recent cold winters and gas price volatility, however, state commissions are looking more favorably on





LDCs entering into long-term contracts.* These commitments by LDCs will be the foundation for the industry to build much-needed infrastructure.* We are in an excellent position to seize opportunities to build that infrastructure and provide additional pipeline and storage services.*

In 2003 our **Utility** operations had an extremely successful year, but it was success we have come to take for granted. Its earnings of $56.8 million were $7.3 million more than last year largely due to colder weather in our Pennsylvania service area. More importantly, despite great fluctuations in gas prices, uncertainties of supply and issues with marketers, our more than 700,000 customers continued to receive safe, reliable, efficient, uninterrupted service.

We achieved these earnings while facing an environment of increasing healthcare and employee benefit costs, spending $49.9 million to upgrade our distribution systems, and maintaining our customer service standards in both New York and Pennsylvania for telephone response times, emergency service response, and overall customer satisfaction, among several others. In New York in particular, where the New York Public Service Commission (NYPSC) sets various customer service goals, our performance once again exceeded the targets in all areas.

The Utility rate-making arena was particularly active for us this year. We successfully completed negotiations on a one-year settlement with the NYPSC, and at its December 18, 2003 meeting, the Pennsylvania Public Utility Commission approved our agreement with the parties in our Pennsylvania rate case. In New York, in addition to maintaining our current rate structure, we negotiated the continuation of the mechanism that provides for a 50/50 sharing between ratepayers and shareholders of earnings in excess of an 11%, versus the previous 11.5%, return on equity. In Pennsylvania, the agreement will increase base revenues by $3.5 million, and allows the Utility to track pension costs (defer pension funding which is different from the pension allowance in rates) as its New York division has done for a number of years.* This pension cost treatment reduces the uncertainty within the Utility with regard to pension and other post-retirement costs and provides some protection from fluctuations in these costs. With our focus on cost savings through attrition and efficiency, this $3.5 million increase in Pennsylvania has been our first since 1995; in New York our non-gas rates have actually decreased on an average annual basis by approximately $13 million compared to the rates in effect in 1998.

In August 2003, the electric industry faced another difficult challenge with the blackout that left 50 million people without power. This incident forced our nation's attention on the weaknesses of the existing electric grid, especially the distance between the sources of power and the location of the demand for power. One solution to this problem is natural gas-powered distributed generation (DG) technology, which offers security, reliability, efficiency and environmental benefits. In essence, DG generates electric power at a site closer to customers than does a central generating station. Our customers who had DG technology operating independently of the electric grid enjoyed continuous electric power during the blackout, highlighting the benefits of DG as an effective energy alternative.

To further stimulate the market for DG in its New York division, the Utility received approval in March from the NYPSC for a three-year DG Pilot Program. This first-of-its-kind program allows the Utility to reduce the initial capital costs of potential DG customers to help them successfully analyze and implement this technology. The program has been well received by our customers and industry partners. We continue to believe that this emerging technology will be a major market for us.*

Our **Exploration and Production** activities produced widely varied results in 2003. Our gas reserves in the Appalachian Basin and our oil reserves in California were increasingly profitable. Our Appalachian gas production increased from 4.4 Bcf to 5.1 Bcf and average gas prices for that production increased from $3.74 to $5.07 per Mcf. While our West Coast oil production decreased slightly from 3.0 to 2.9 million barrels, average oil prices for that production increased from $19.94 to $26.12 per barrel. These kinds of results have persuaded us that exploration and production should remain an integral part of our business plan.* Oil and gas reserves are a logical hedge against inflation for us and they are a natural diversification versus the utility where higher prices are decidedly negative.

Our on-shore drilling program has been very successful, especially in the Appalachian Basin where we have extensive lease and fee holdings of nearly 900,000 net acres and gas reserves of approximately 81 Bcf. Existing gathering systems facilitate our ability to transport natural gas produced from this region to market. We plan to drill approximately 70 shallow wells there in 2004.* In California, production from our long-lived heavy oil reserves continues; about 52 development wells are planned in 2004 versus 31 in 2003, reflecting our positive results in that region.*

On the other hand, our Canadian oil and gas properties in Southeast Saskatchewan were not performing to expectations, and we sold them at a loss of $39.6 million after tax. Our Gulf of Mexico production continued to decline rapidly as is typical of the area. While we have a few choice prospects left to drill there, we do not see many more on the horizon; therefore, although our short-term Gulf prospects are exciting and could be very profitable, we continue to focus elsewhere for the longer term.*

Our major growth opportunity is expected to be gas production in Canada and, accordingly, we are budgeting $38.2 million for Canadian drilling.* Canada has been much less explored than the lower 48 states and the reserves are typically longer lived than those in the Gulf of Mexico.

For this segment as a whole, the loss on the sale of the Southeast Saskatchewan properties of $39.6 million, together with the recording of $28.9 million of after-tax impairment charges related to Canadian oil and gas assets, as well as a $0.6 million first quarter charge resulting from a change in accounting for plugging and abandonment costs, led to a loss in this segment of $31.9 million this year. Absent these charges, this year's earnings were $37.3 million. Last year's earnings were $26.9 million, but did not reflect any significant charges.

Increases in the weighted average price of gas and oil after hedging ($4.47 vs. $3.58 per Mcf and $21.84 vs. $19.94 per barrel) more than offset the overall decrease in natural gas and oil production. Total annual production of 74.2 Bcfe was 13.2 Bcfe lower than last year's production, and crude oil and gas reserves declined from 856.5 Bcfe to 669.7 Bcfe. Substantial reserve revisions, primarily to oil and gas reserves associated with the Southeast Saskatchewan properties, accounted for the decline.

Planned production for fiscal 2004 is expected to be in the range of 57 to 62 Bcfe with a capital expenditure budget of $90 million; natural gas is expected to account for approximately 55% of this production.* We expect to improve the performance of this segment by applying a more conservative approach to developing the assets we have, living within cash flow, controlling production costs, and focusing on those areas where we have been successful in the past.*

For many years, we have been keenly aware of the value of our **Timber** assets. In 2003, that value played a key role in facilitating our investment in the Empire State Pipeline. The sale of approximately 70,000 acres of timber brought $186 million in cash, which was used to pay off the short-term debt incurred for the acquisition of Empire. Earnings for the Timber segment, including an after-tax gain on the sale of $102.2 million, were $112.5 million. Even though timber harvesting and production slowed while the sale was pending, we produced nearly 34 million board feet, an increase of 6.7% from last year.

Because we sold this acreage using a tax-deferred transaction, we selected the land that had the lowest cost basis. These trees were the ones we had held the longest and were the most mature. Our remaining timber holdings, which consist of approximately 87,000 acres with 330 million board feet, tend to be younger and to have a higher cost basis. Thus, 2004 earnings for this segment are expected to decline as we expect to harvest less timber and to have higher depletion expense per unit.* The sale was the "proof in the pudding" of the value of the timber business, demonstrating the gains that are possible there, and evidence of the strength and flexibility this segment affords us.

The **Energy Marketing** segment is the largest marketer on the Utility system, selling natural gas under a variety of pricing arrangements to industrial, commercial, public authority, and residential customers. In addition to marketing natural gas, this segment also offers energy management services to several of its industrial and large commercial customers.

This segment does not engage in speculative energy trading. This year, its earnings were $5.9 million, a decrease of $2.7 million from last year's record earnings, making this year's earnings second only to 2002's extraordinary performance. During fiscal 2003, this segment sold approximately 45 Bcf of gas, a 37% increase over last year. The addition of several high volume customers accounted for most of that increase, but the higher throughput was offset by lower margins. This segment is now a consistent performer and, moreover, it is a logical link between us and our end users.*

The **International** segment incurred a loss of $9.6 million, $5.2 million more than last year's loss of $4.4 million. An impairment of $8.3 million was recorded this year as a result of the Company's adoption of an accounting rule that no longer allows the amortization of goodwill expense. Absent the change in accounting, this year's loss was $1.4 million, an improvement of $3.1 million from last year.

Other Business

The Toro Partners landfill gas systems were acquired by our subsidiary, Upstate Energy Inc., in June for $47.8 million. These short-distance landfill gas pipeline systems are in eight separate locations in six states where we now purchase, transport and resell landfill gas to industrial and governmental customers. This acquisition offers the opportunity to combine our favorable experience with landfill gas sites with our expertise in pipeline operations.

Environmental regulations now require that landfill methane gas be gathered rather than flared, and we are using methane to generate wholesale electricity in New York State and to sell as boiler fuel elsewhere. This gas, and the process of using it, is not only environmentally friendly, but it provides industrial customers with a lower-cost alternative. As natural gas becomes more valuable, landfill gas projects will become more attractive, and we will continue to seek opportunities to expand this business.*

Management Changes

This past year, Ronald J. Tanski was named Controller of National Fuel, succeeding Gerald T. Wehrlin who retired from that position last February. In addition, at last year's Annual Shareholder Meeting, R. Don Cash was elected to serve on your Board. Don's many years of experience in the industry, and more recently as the former Chairman of Questar Corporation, another integrated natural gas company, will prove invaluable to your Company. Following the acquisition of Toro Partners, Bruce H. Hale was named President of Upstate Energy Inc. Lastly, two of our distinguished Board members, Bernard J. Kennedy and James V. Glynn, will be retiring as Directors at the upcoming Annual Meeting. We thank Jim for his many years of service to your Company, and we particularly thank Bernie, whose 45 years of service typify the kind of lifelong employee dedication to National Fuel that has enabled this Company to prosper for more than 100 years.

We have made an unusual number of changes this past year, but we firmly believe that each of them is for the better. As we continue our journey into the 21st century, we remain committed today as we have always been to honesty and fair dealing, to growing shareholder value through timely investments in the energy industry, to being a participant in the natural gas value chain from the bottom of the well to the burner tip, to responsibly developing resources, to reliably delivering energy, and to providing excellent service to all our customers. We continue to remain focused on the fundamentals that have driven your Company for the last 101 years – our belief in natural gas and the gas business; our belief in the integrity of our employees; and our belief in the benefits of being an asset-based diversified energy company.

Philip C. Ackerman

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

December 29, 2003

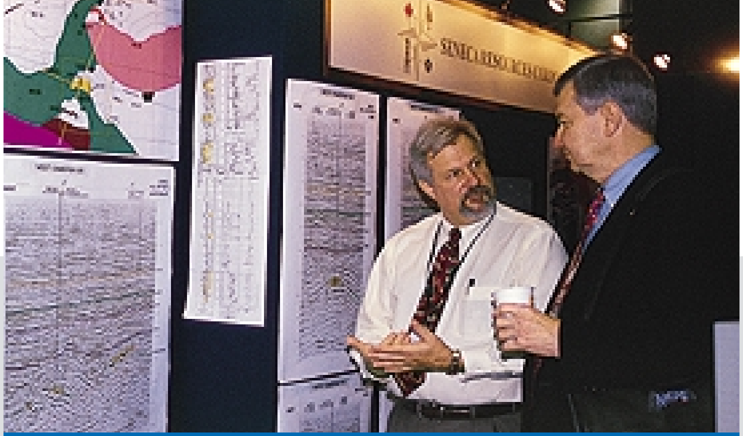
Note: This document contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements, including those designated by an asterisk ("*"), should be read with the cautionary statements and important factors included at Item 7 of the Company's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

DEVELOPING *Resources*

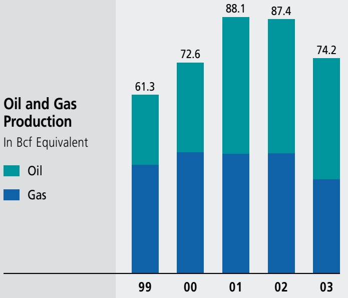
The Exploration and Production and Timber segments proficiently and carefully manage our oil, natural gas and hardwood resources.

Seneca has been actively developing natural gas and oil reserves in the Upper Devonian Sandstones of the Westline region, south of Bradford, Pa., where about 50 wells were drilled this year. In order to increase the wells' production capabilities, they are hydraulically fractured using a concentrated sand and gelled water slurry, and part of this operation is shown here. Once the well is completed, Seneca has a proven record of responsible management for the revitalization of plant life on the land affected by the activities, as shown in the smaller photograph taken in early October of another site in the Westline area that was drilled in August.

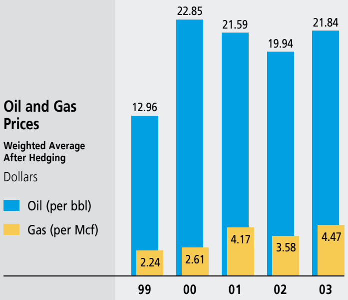
Seneca continues to focus its operations on the exploration and production of natural gas reserves. This is especially true in the Canadian division. The rig in the background is drilling for natural gas in a proven producing trend at Aerial Field near Drumheller, Alberta. The pipes in the foreground are part of the surface separation equipment of a well that is currently on production in the same trend. Wells in this area typically start producing at 0.5 to 1.0 Mmcf per day.

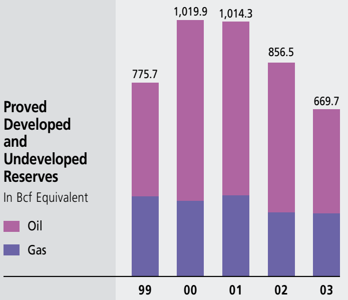


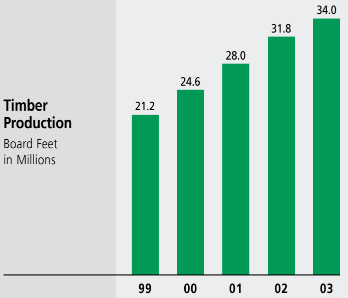
Each winter, Seneca participates in the annual North American Prospect Expo in Houston, Texas where, in one location, Seneca can seek new opportunities to expand its onshore exploration while also pursuing deals for its existing offshore rights. Here, Seneca geologist Leonard Cichowski, left, talks with another company's convention participant.



At the sawmill in Marienville, Pa., Highland Forest Resources equipment operator Russ Mainwaring manipulates a cherry veneer log using a Caterpillar 322 log handler. This piece of equipment, purchased in 2003, facilitates the sorting of thousands of logs each year to obtain optimum value.







DELIVERING *Energy*

The Pipeline and Storage segment transports natural gas from market hubs to customers and offers natural gas storage services along its path.

Empire State Pipeline, acquired by National Fuel in February 2003, transports natural gas through western and central New York to many customers, including regional gas utilities. At this gas metering and regulating station near Mendon, N.Y., Empire's metering facilities are exposed in the background with the New York State Thruway behind. Empire corrosion technician Mike Humphrey, right, tests the cathodic protection levels of the pipeline with New York Public Service Commission specialist Al Saraceni as part of a routine safety inspection at the station.

To improve and maintain the deliverability of the storage fields serving its transmission system, the Pipeline and Storage segment installed new well casings and hydraulically fractured several storage wells, including one in New York at Bennington Field, shown here. With the well successfully reopened, a rig crew installs new 4½-inch casing. The segment expects a 200% increase in the withdrawal and injection capabilities of these wells as a result of these efforts.*

Through the acquisition of Toro Partners, National Fuel is now involved in delivering another form of energy – landfill gas. This Toro facility in Waynesburg, Ohio compresses the landfill gas, removes the unwanted components and prepares it for delivery into the Dominion East Ohio system located about nine miles away.

The Pennsylvania division of the Pipeline and Storage segment invested in handheld data collection technology this year to aid well tenders in electronically collecting information about its storage wells. Here, Kane Field employee Terry Johnson uses his data collector at a Wellendorf storage well near Clermont, Pa.

Approximately 4,000 feet of the Line K (1954 bare-steel) pipeline in West Seneca, N.Y. was replaced this summer with new 20-inch diameter coated steel pipe. This replacement is part of ongoing upgrades to the Pipeline and Storage transmission system. Horizontal directional equipment was used to bore a hole that was 940 feet long and 30 inches in diameter for the new pipeline to be installed underneath Cazenovia Creek and Ridge Road as shown here. This technique is environmentally friendly and the creek was not disturbed.

SERVING Customers

The Utility and Energy Marketing segments provide quality customer service and program options to natural gas customers.

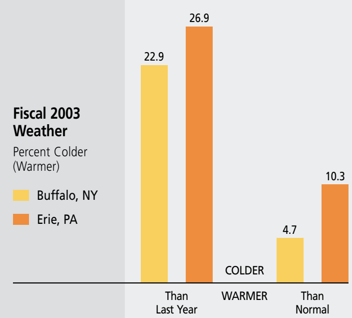
Through its distributed generation research and development program, National Fuel helped fund and coordinate the installation of four Waukesha engines that collectively produce 2,000 kilowatts of power to operate printing and packaging lines, and a 200-ton absorption chiller that uses heat produced by the engines to control paper board moisture levels at Mod-Pac, a paper and packaging printing company in Buffalo, N.Y. Heat from the engines is also used for space heating in approximately 280,000 square feet of the building. Here, Utility energy consultant Howard Patton and Mod-Pac facilities manager Steve Anderson monitor one engine's operations.

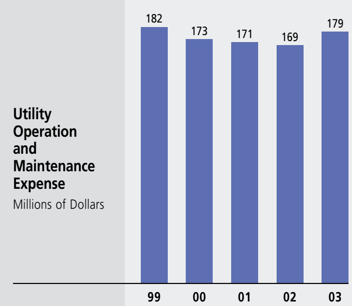
Utility crews work even in snowy and frozen conditions to improve the safety and reliability of the system by replacing old steel pipe with new plastic lines. This was the case here, at a residence in Tonawanda, N.Y., where gas service was renewed.

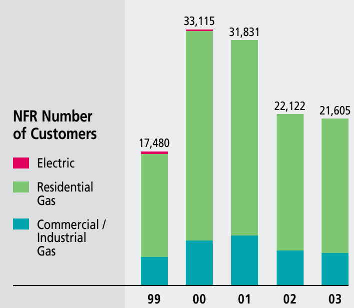
Newly hired supervisory employees had the opportunity to tour the Utility's Buffalo operations and customer service call center, shown here. In the foreground, Utility manager Kathy Navarro speaks to one group while another group, in the background, tours the call center facility.

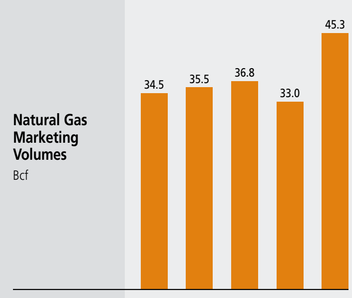
General Electric's Erie, Pa. plant, which manufactures locomotives, is in the process of replacing three coal boilers with natural gas boilers, which will produce steam for the plant. The Utility installed nearly one mile of 12-inch diameter pipeline, shown here, to meet their anticipated demand of over 300,000 cubic feet of gas per hour.

The Utility's 126 customer service phone representatives at the Erie, Pa. and Buffalo, N.Y. call centers attended a training session in the spring that helped to freshen their customer service and phone skills. Here, a consultant shares ideas with one group.









Erie Indemnity, a diversified insurance company and the #2 employer in Erie County, Pa., is one of the Energy Marketing segment's newest accounts. Its headquarters in Erie has an annual load of 30,000 Dth. Here, National Fuel Resources sales manager Bob Tullio, right, meets with Jim Roehm, Erie Indemnity's senior vice president of corporate services, in one of the four buildings within their headquarters complex.

Officers

National Fuel Gas Company

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

Joseph P. Pawlowski
Treasurer

Ronald J. Tanski
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

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.

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

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 Astronics Corporation, M&T Bank Corporation and Seneca Foods Corporation.

R. Don Cash [1, 7]
Chairman Emeritus since May 2003 and Director since May 1978 of Questar Corporation. Former Chairman, Chief Executive Officer and President of Questar Corporation from May 1984 to February 2001. Director of Zions Bancorporation, Texas Tech Foundation and Associated Electric & Gas Insurance Services Limited.

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.

Bernard J. Kennedy
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.

George L. Mazanec [1, 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 [3, 5]
President and Chief Executive Officer of the Gas Technology Institute since April 2000. Board member since July 2000. Director of Nicor Inc. and Niagara University.

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

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, 2003

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.)
6363 Main Street **Williamsville, New York** (Address of principal executive offices)	**14221** (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. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). YES ✔ NO __

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $1,733,892,000 as of March 31, 2003.

Common Stock, $1 Par Value, outstanding as of November 30, 2003: 81,600,674 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for the Annual Meeting of Shareholders to be held February 19, 2004 are incorporated by reference into Part III of this report.

CONTENTS

For The Fiscal Year Ended September 30, 2003

Form 10-K

Part I

ITEM 1 Business
- The Company and its Subsidiaries **19**
- Rates and Regulation **21**
- The Utility Segment **21**
- The Pipeline and Storage Segment **22**
- The Exploration and Production Segment **22**
- The International Segment **22**
- The Energy Marketing Segment **22**
- The Timber Segment **22**
- All Other Category and Corporate Operations **23**
- Sources and Availability of Raw Materials **23**
- Competition **23**
- Seasonality **25**
- Capital Expenditures **26**
- Environmental Matters **26**
- Miscellaneous **26**
- Executive Officers of the Company **26**

ITEM 2 Properties
- General Information on Facilities **27**
- Exploration and Production Activities **28**

ITEM 3 Legal Proceedings **31**

ITEM 4 Submission of Matters to a Vote of Security Holders **32**

Part II

ITEM 5 Market for the Registrant's Common Equity and Related Stockholder Matters **32**

ITEM 6 Selected Financial Data **33**

ITEM 7 Management's Discussion and Analysis of Financial Condition and Results of Operation **34**

ITEM 7A Quantitative and Qualitative Disclosures About Market Risk **61**

ITEM 8 Financial Statements and Supplementary Data **61**

ITEM 9 Changes in and Disagreements with Accountants on Accounting and Financial Disclosure **101**

ITEM 9A Controls and Procedures **101**

Part III

ITEM 10 Directors and Executive Officers of the Registrant **102**

ITEM 11 Executive Compensation **102**

ITEM 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters **102**

ITEM 13 Certain Relationships and Related Transactions **103**

ITEM 14 Principal Accountant Fees and Services **103**

Part IV

ITEM 15 Exhibits, Financial Statement Schedules and Reports on Form 8-K **104**

Signatures **107**

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 Operation (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 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. 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 733,000 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, and Empire State Pipeline (Empire), a New York joint venture between two wholly-owned entities of the Company. 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. Empire, an intrastate pipeline company, transports natural gas for Distribution Corporation and for other utilities, large industrial customers and power producers in New York State. Empire owns a 157-mile pipeline that extends generally from the United States/Canadian border at the Niagara River near Buffalo, New York to near Syracuse, New York. The Company acquired Empire, which is regulated by the State of New York Public Service Commission (NYPSC), in February 2003. Seneca Independence Pipeline Company was formed to hold a one-third general partnership interest in Independence Pipeline Company, which was dissolved in 2002.

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, and in the Gulf Coast region of Texas and Louisiana. Also, Exploration and Production operations are conducted in the provinces of

Alberta, Saskatchewan and British Columbia in Canada by Seneca Energy Canada, Inc. (SECI), formerly Player Resources Ltd. SECI is an Alberta, Canada corporation and a subsidiary of Seneca. In September 2003, the Company sold its Southeast Saskatchewan properties, reducing its oil reserves by 19,400 thousand barrels (Mbbl) and its gas reserves by 270 million cubic feet (MMcf). At September 30, 2003 the Company had remaining U.S. and Canadian reserves of 69,764 Mbbl and 251,117 MMcf.

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's wholly-owned subsidiary, 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. Horizon B.V. is also pursuing power development projects in other parts of Europe.

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 New York 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 two sawmill operations in northwestern Pennsylvania and processes timber consisting primarily of high quality hardwoods. In August 2003, the Company sold approximately 70,000 acres of timber property. At September 30, 2003, the Company had approximately 87,000 acres of timber property remaining.

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 H - 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 the purchase, sale and transportation of landfill gas in Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. On June 3, 2003, Upstate and a wholly owned subsidiary of Upstate acquired all of the partnership interest in Toro Partners, LP (Toro), a limited partnership which owns and operates eight short-distance landfill gas pipeline companies. Further information can be found in Item 7, MD&A and also in Item 8 at Note J-Acquisitions;

• 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 which was dissolved October 31, 2003;

• 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 and landfill gas pipeline facilities.

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2003.

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, intra-company transactions and limitations on diversification. In 2003, both houses of Congress passed comprehensive energy bills that include repeal of the Holding Company Act. On November 17, 2003, a conference committee of the House and Senate approved a conference agreement (i.e, a compromise bill), which was passed by the House on November 19, 2003. The conference agreement is pending before the Senate and certain senators have indicated that it is likely to be considered in January 2004 when Congress reconvenes.* The conference agreement would repeal the Holding Company Act effective one year after the date of enactment of the new law. The measure, if enacted, would replace the Holding Company Act with provisions designed to give the Federal Energy Regulatory Commission (FERC) and state public utility regulatory commissions greater access to the books and records of companies in holding company systems. Also, in some cases, FERC would have jurisdiction to approve cost allocations among holding company system companies. If the Holding Company Act is repealed, it is possible that some state legislatures will enact new laws designed to give state public utility regulatory commissions regulatory powers over holding companies similar to those now exercised by the SEC. The Company is unable to predict at this time what the ultimate outcome of legislative or regulatory changes will be and, therefore, whether the Holding Company Act will be repealed and what impact the repeal of the Holding Company Act might have on the Company.*

The Utility segment's rates, services and other matters are regulated by the 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 with respect to Supply Corporation are regulated by FERC and by the NYPSC with respect to Empire. 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 31.7% of the Company's 2003 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 2003 net income available for common stock.

Supply Corporation currently has service agreements for substantially all of its firm transportation capacity, which totals approximately 2,093 thousand dekatherms (MDth) per day. The Utility segment accounts for approximately 1,179 MDth per day or 56.3% of the total capacity, and the Energy Marketing segment represents another 74 MDth per day or 3.5% of the total capacity. The remaining 841 MDth or 40.2% of Supply Corporation's firm transportation capacity is subject to firm contracts with nonaffiliated customers.

Supply Corporation has service agreements for substantially all of its firm storage capacity, which totals approximately 68,728 MDth. The Utility segment has contracted for 31,395 MDth or 45.7% of the total capacity and the Energy Marketing segment accounts for another 3,555 MDth or 5.2% of the total capacity. Nonaffiliated customers have contracted for the remaining 33,778 MDth or 49.1% 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.*

Empire has service agreements for substantially all of its firm transportation capacity for the 2003-2004 winter period, which totals approximately 567 MDth per day. The Utility segment accounts for approximately 60 MDth per day or 10.6% of the total capacity, and the Energy Marketing segment accounts for approximately 10 MDth per day or 1.8% of the total capacity. The remaining 497 MDth per day or 87.6% of Empire's firm winter transportation capacity is subject to firm contracts with nonaffiliated customers.

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 incurred a net loss in 2003. The impact of this net loss in relation to the Company's 2003 net income available for common stock was negative 17.8%.

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 2003. The impact of this segment's net loss in relation to the Company's 2003 net income available for common stock was negative 5.4%.

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 3.3% of the Company's 2003 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 62.8% of the Company's 2003 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 contributed approximately 0.1% of the Company's 2003 net income available for common stock.

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 2003, the Utility segment purchased 123.0 billion cubic feet (Bcf) of gas. Gas purchases from producers and suppliers in the southwestern United States and Canada under firm contracts (seasonal and longer) accounted for 63% of these purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for 37% of the Utility segment's 2003 gas purchases. Gas purchases from BP Energy Company (13%), Amerada Hess Corporation (13%), ConocoPhillips (12%), Anadarko Petroleum Corporation (11%) and Occidental Energy Marketing, Inc. (10%) accounted for 59% of the Utility's gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2003.

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. Empire transports gas owned by its customers, whose gas originates in the southwestern and mid-continent regions of the United States as well as Canada. Additional discussion of proposed pipeline projects appears below under "Competition" and in Item 7, MD&A.

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 H - 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 2003 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 is expected to have reserves through 2030, although the Company has not been provided with an independent reserve study to support this information.* Natural gas is imported into the Czech Republic from sources in Russia and the North Sea and is transported 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. Oil is also imported into the Czech Republic. 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. Approximately eighty percent of the timber processed during fiscal year 2003 came from land owned by Seneca; however, this percentage is expected to drop to approximately 50% in fiscal year 2004 as a result of the previously discussed sale of approximately 70,000 acres of timber property.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2003, this segment purchased 45 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 has enhanced the competitive position of natural gas relative to other energy sources, such as fuel oil or electricity, by removing some of the historical 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 has been 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 the impact will be on the Company of such restructuring or any future restructuring in response to the August 2003 Northeast blackout, legislation or other events.*

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, since regulators in Pennsylvania have not pursued such programs recently, and since there have not been any significant new market entrants in New York, the Utility segment's traditional distribution function remains largely unchanged.

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 northeast 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.*

On February 6, 2003, the Company acquired Empire. Empire competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and upstate New York in particular. Empire is particularly well situated to provide transportation from Canadian sourced gas, and its facilities are readily expandable. These characteristics provide Empire the opportunity to compete for an increased share of the gas transportation markets.

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 project, 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 oil and natural gas producers and marketers with respect to sales of oil and natural gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other oil and natural gas producers with respect to exploration and development prospects.

To compete in this environment, Seneca and SECI each originate and act as operator on most prospects, minimize the 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, which sells electricity at the wholesale level, 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.

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 allowed 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 recover the variable costs associated with actual transportation or storage of gas.

Volumes transported by Empire may vary materially depending on weather, and can have a moderate effect on its revenues. Empire's allowed rates are based on a modified fixed-variable rate design, which allows recovery of most fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover variable costs associated with actual transportation of gas, to recover return on equity, and to recover income taxes.

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 G - Commitments and Contingencies.

Miscellaneous

The Company and its wholly-owned or majority-owned subsidiaries had a total of 3,037 full-time employees at September 30, 2003, with 2,140 employees in all of its U.S. operations and 897 employees in its international operations. This is a decrease of 4.4% from the 3,177 total employed at September 30, 2002.

Agreements covering employees in collective bargaining units in New York were renegotiated, effective as of November 2003, and are scheduled to expire in February 2008. Certain agreements covering employees in collective bargaining units in Pennsylvania were renegotiated, effective November 2003, and are scheduled to expire in April 2009. Other agreements covering employees in collective bargaining units in Pennsylvania were renegotiated, effective November 2003, and are scheduled to expire in May 2009. An agreement covering employees in collective bargaining units in the Czech Republic is scheduled to expire in December 2004. Negotiations to renew such agreements are ongoing.

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 makes its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on the Company's internet website, www.nationalfuelgas.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC.

Executive Officers of the Company as of November 15, 2003[(1)]

Name and Age [(2)]	Current Company Positions and Other Material Business Experience During Past Five Years [(3)]
Philip C. Ackerman (59)	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 (60)	President of Supply Corporation since March 2000; President of Empire since February 2003; 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 (50)	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 (56)	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.

Bruce H. Hale (54)	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 (62)	Treasurer of the Company 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; Treasurer of Empire since February 2003; and Secretary of Supply Corporation since October 1995.
Walter E. DeForest (62)	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 (50)	Secretary of the Company since October 1995; Senior Vice President of Distribution Corporation since July 2001; and Vice President of Distribution Corporation from June 1994 to July 2001.
Ronald J. Tanski (51)	Controller of the Company since February 2003; 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 (51)	Senior Vice President of Supply Corporation since July 2001; and Vice President of Supply Corporation from April 1993 to July 2001.
James D. Ramsdell (48)	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, 2003.
(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 $2.9 billion at September 30, 2003. Approximately 57% of this investment was in the Utility and Pipeline and Storage segments, which are primarily located in western and central New York and northwestern Pennsylvania. The Exploration and Production segment, which has the next largest investment in net property, plant and equipment (32%), 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 Alberta, Saskatchewan and British Columbia in Canada. The remaining investment in net property, plant and equipment consisted primarily of the International segment (8%) which is located in the Czech Republic and the Timber segment (3%) 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, and to expand and improve transmission and distribution facilities for both retail and transportation customers. Net property, plant and equipment has increased $666 million, or 30%, since 1998.

The Utility segment had a net investment in property, plant and equipment of $972.0 million at September 30, 2003. The net investment in its gas distribution network (including 14,773 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, 2003.

The Pipeline and Storage segment had a net investment of $685.6 million in property, plant and equipment at September 30, 2003. Transmission pipeline, with a net cost of $262.6 million, represents 38% of this segment's total net investment and includes 2,601 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 $87.0 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 $925.8 million at September 30, 2003. Of this amount, $809.3 million relates to properties located in the United States. The remaining net investment of $116.5 million relates to properties located in Canada.

The International segment had a net investment in property, plant and equipment of $219.2 million at September 30, 2003. 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 $87.6 million at September 30, 2003. Located primarily in northwestern Pennsylvania, the net investment includes two sawmills and approximately 87,000 acres of land and timber.

The Utility and Pipeline and Storage segments' facilities provided the capacity to meet the Company's 2003 peak day sendout, including transportation service, of 1,744.8 MMcf, which occurred on January 23, 2003. Withdrawals from storage of 653.8 MMcf provided approximately 37.5% of the requirements on that day.

Company maps are included in exhibit 99.3 of this Form 10-K and are incorporated herein by reference.

Exploration and Production Activities

The Company 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, and in the Gulf Coast region of Texas and Louisiana. Also, Exploration and Production operations are conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada. 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 2003, Seneca's proved developed and undeveloped reserves decreased significantly. Natural gas reserves decreased from 258 Bcf at September 30, 2002 to 251 Bcf at September 30, 2003 and oil reserves decreased from 99,717 Mbbl to 69,764 Mbbl. These decreases are attributed to several factors: (i) U.S. and Canadian production and sales of Canadian properties (refer to Item 7, MD&A) and (ii) downward reserve revisions, primarily related to the Canadian properties sold during the year (reflected in Note N as revisions of previous estimates). Seneca's proved developed and undeveloped reserves also decreased in 2002 as compared to 2001. 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 Mbbl to 99,717 Mbbl. These decreases are 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 continuing to shift 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, 2003 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, a statistical agency of the U.S. Department of Energy (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	**2003**	2002	2001
United States			
Gulf Coast Region			
Average Sales Price per Mcf of Gas	**$5.41**	$2.89	$4.93
Average Sales Price per Barrel of Oil	**$29.17**	$22.83	$27.47
Average Sales Price per Mcf of Gas (after hedging)	**$4.22**	$3.69	$3.65
Average Sales Price per Barrel of Oil (after hedging)	**$27.88**	$22.51	$24.11
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	**$0.56**	$0.60	$0.41
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	**75**	100	115
West Coast Region			
Average Sales Price per Mcf of Gas	**$5.01**	$2.86	$10.18
Average Sales Price per Barrel of Oil	**$26.12**	$19.94	$24.06
Average Sales Price per Mcf of Gas (after hedging)	**$5.12**	$2.86	$7.81
Average Sales Price per Barrel of Oil (after hedging)	**$23.67**	$20.09	$20.67
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	**$1.00**	$0.81	$0.81
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	**59**	63	59
Appalachian Region			
Average Sales Price per Mcf of Gas	**$5.07**	$3.74	$5.03
Average Sales Price per Barrel of Oil	**$28.77**	$23.76	$28.51
Average Sales Price per Mcf of Gas (after hedging)	**$5.10**	$3.74	$4.95
Average Sales Price per Barrel of Oil (after hedging)	**$28.77**	$23.76	$28.51
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	**$0.43**	$0.53	$0.51
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	**14**	12	11
Total United States			
Average Sales Price per Mcf of Gas	**$5.28**	$2.99	$5.53
Average Sales Price per Barrel of Oil	**$27.16**	$21.03	$25.43
Average Sales Price per Mcf of Gas (after hedging)	**$4.52**	$3.58	$4.25
Average Sales Price per Barrel of Oil (after hedging)	**$25.11**	$21.01	$22.06
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	**$0.72**	$0.67	$0.55
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	**148**	175	185
Canada			
Average Sales Price per Mcf of Gas	**$4.67**	$2.29	$2.41
Average Sales Price per Barrel of Oil	**$26.41**	$19.94	$24.29
Average Sales Price per Mcf of Gas (after hedging)	**$4.20**	$3.59	$2.41
Average Sales Price per Barrel of Oil (after hedging)	**$15.85**	$18.11	$20.85
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	**$1.65**	$1.29	$1.34
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	**55**	64	55
Total Company			
Average Sales Price per Mcf of Gas	**$5.18**	$2.88	$5.39
Average Sales Price per Barrel of Oil	**$26.90**	$20.63	$24.99
Average Sales Price per Mcf of Gas (after hedging)	**$4.47**	$3.58	$4.17
Average Sales Price per Barrel of Oil (after hedging)	**$21.84**	$19.94	$21.59
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	**$0.97**	$0.84	$0.73
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	**203**	239	240

PRODUCTIVE WELLS

At September 30, 2003		United States							
		Gulf Coast Region		West Coast Region		Appalachian Region		Total U.S.	
		Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells	– Gross	**31**	**38**	**—**	**1,119**	**1,874**	**31**	**1,905**	**1,188**
Productive Wells	– Net	**18**	**17**	**—**	**1,108**	**1,792**	**25**	**1,810**	**1,150**

PRODUCTIVE WELLS

At September 30, 2003		Canada		Total Company	
		Gas	Oil	Gas	Oil
Productive Wells	– Gross	**155**	**47**	**2,060**	**1,235**
Productive Wells	– Net	**114**	**31**	**1,924**	**1,181**

DEVELOPED AND UNDEVELOPED ACREAGE

At September 30, 2003		United States					
		Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada	Total Company
Developed Acreage	– Gross	**109,635**	**10,343**	**509,021**	**628,999**	**112,893**	**741,892**
	– Net	**79,489**	**8,532**	**482,596**	**570,617**	**76,000**	**646,617**
Undeveloped Acreage	– Gross	**259,534**	**1,119**	**439,095**	**699,748**	**439,385**	**1,139,133**
	– Net	**137,817**	**860**	**414,710**	**553,387**	**336,538**	**889,925**

As of September 30, 2003, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 131,844 acres in 2004 (107,191 net acres), 129,613 acres in 2005 (109,446 net acres), 101,610 acres in 2006 (93,458 net acres), and 776,066 acres thereafter (579,830 net acres).

DRILLING ACTIVITY

For the Year Ended September 30		Productive			Dry		
		2003	2002	2001	2003	2002	2001
United States							
Gulf Coast Region							
Net Wells Completed	– Exploratory	**1.25**	1.27	2.83	**—**	3.67	1.93
	– Development	**2.10**	0.31	4.64	**—**	—	—
West Coast Region							
Net Wells Completed	– Exploratory	**—**	—	—	**—**	—	—
	– Development	**30.97**	47.99	86.96	**—**	2.00	1.00
Appalachian Region							
Net Wells Completed	– Exploratory	**3.00**	3.00	9.00	**0.10**	1.00	3.00
	– Development	**58.00**	27.00	17.00	**—**	0.10	—
Total United States							
Net Wells Completed	– Exploratory	**4.25**	4.27	11.83	**0.10**	4.67	4.93
	– Development	**91.07**	75.30	108.60	**—**	2.10	1.00
Canada							
Net Wells Completed	– Exploratory	**5.00**	0.20	10.00	**2.50**	4.00	11.00
	– Development	**17.16**	33.70	61.14	**5.00**	7.90	2.75
Total							
Net Wells Completed	– Exploratory	**9.25**	4.47	21.83	**2.60**	8.67	15.93
	– Development	**108.23**	109.00	169.74	**5.00**	10.00	3.75

PRESENT ACTIVITIES

At September 30, 2003		United States: Gulf Coast Region	United States: West Coast Region	United States: Appalachian Region	United States: Total U.S.	Canada	Total Company
Wells in Process of Drilling (1)	– Gross	**1.00**	**3.00**	**21.00**	**25.00**	**36.00**	**61.00**
	– Net	**0.67**	**3.00**	**20.05**	**23.72**	**25.08**	**48.80**

(1) Includes wells awaiting completion.

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. The waterflood project has matured and injection was ceased in early 2003. The current oil production from the Ellis lease is 220 barrels of oil per day from 88 production wells.

ITEM 3 LEGAL PROCEEDINGS

In an action instituted in the New York State Supreme Court, Chautauqua County on January 31, 2000 against Seneca, NFR 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 that (a) Seneca underpaid royalties due under leases operated by it, and (b) 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). On December 23, 2002, the court granted certification of the proposed class, as modified to exclude those leaseholders whose leases provide for calculation of royalties based upon a flat fee, or flat fee per cubic foot of gas produced. The court's order states that there are approximately 749 potential class members. Discovery has begun on the merits of the claims and the case will eventually be tried or settled.

In an action instituted in the New York State Supreme Court, Kings County on February 18, 2003 against Distribution Corporation and Paul J. Hissin, an unaffiliated third party, plaintiff Donna Fordham-Coleman, as administratrix of the estate of Velma Arlene Fordham, alleges that Distribution Corporation's denial of natural gas service in November 2000 to the plaintiff's decedent, Velma Arlene Fordham, caused decedent's death in February 2001. Plaintiff seeks damages for wrongful death and pain and suffering, plus punitive damages. Distribution Corporation has denied plaintiff's material allegations, set up seven affirmative defenses in separate verified answers and filed a cross-claim against the co-defendant. Distribution Corporation believes and will vigorously assert that plaintiff's allegations lack merit. On October 24, 2003, the Supreme Court, Kings County, entered an order granting Distribution Corporation's motion to change venue of the action to New York State Supreme Court, Erie County. Plaintiff has not appealed that order. For discussion of a related matter before the NYPSC, refer to Item 7 - MD&A of this report under the heading "Regulatory Matters."

The Company believes, based on the information presently known, that the ultimate resolution of these matters, individually or in the aggregate, 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 outcomes of these matters, and it is possible that the outcomes, individually or in the aggregate, 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 G - 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 2003.

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 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 8 at Note D - Capitalization and Short-Term Borrowings and Note M - Market for Common Stock and Related Shareholder Matters (unaudited).

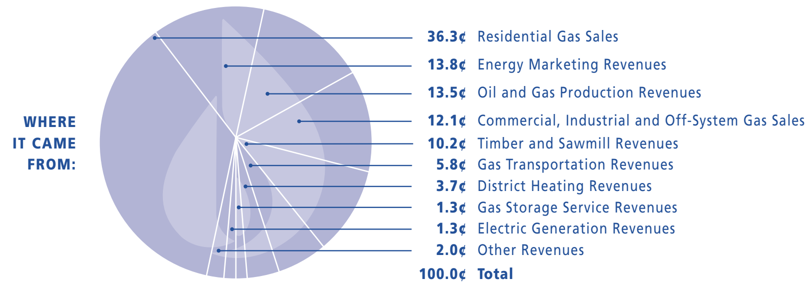
On July 1, 2003, the Company issued a total of 2,400 unregistered shares of Company common stock to the eight non-employee directors of the Company then serving on the Board of Directors, 300 shares to each such director. All of these unregistered shares issued on July 1, 2003 were issued as partial consideration for such directors' services during the quarter ended September 30, 2003, 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

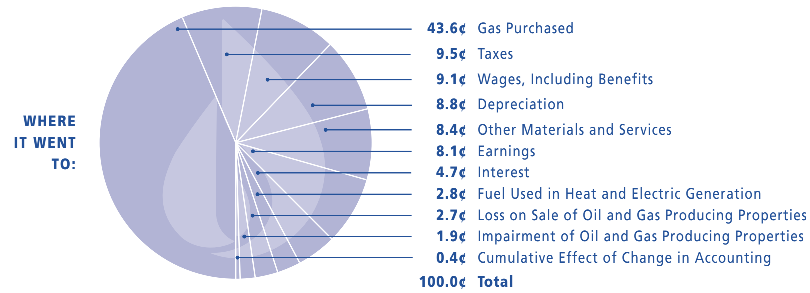
Year Ended September 30	2003	2002	2001	2000	1999
Summary of Operations *(Thousands)*					
Operating Revenues	**$2,035,471**	$1,464,496	$2,059,836	$1,412,416	$1,254,402
Operating Expenses:					
Purchased Gas	**963,567**	462,857	1,002,466	488,383	397,053
Fuel Used in Heat and Electric Generation	**61,029**	50,635	54,968	54,893	55,788
Operation and Maintenance	**386,270**	394,157	364,318	350,383	328,800
Property, Franchise and Other Taxes	**82,504**	72,155	83,730	78,878	91,146
Depreciation, Depletion and Amortization	**195,226**	180,668	174,914	142,170	124,778
Impairment of Oil and Gas Producing Properties	**42,774**	—	180,781	—	—
	1,731,370	1,160,472	1,861,177	1,114,707	997,565
Gain on Sale of Timber Properties	**168,787**	—	—	—	—
Loss on Sale of Oil and Gas Producing Properties	**(58,472)**	—	—	—	—
Operating Income	**414,416**	304,024	198,659	297,709	256,837
Other Income (Expense):					
Income from Unconsolidated Subsidiaries	**535**	224	1,794	1,669	999
Impairment of Investment in Partnership	**—**	(15,167)	—	—	—
Other Income	**6,887**	7,017	10,639	6,366	11,344
Interest Expense on Long-Term Debt	**(92,766)**	(90,543)	(81,851)	(67,195)	(65,402)
Other Interest Expense	**(12,290)**	(15,109)	(25,294)	(32,890)	(22,296)
Income Before Income Taxes and Minority Interest in Foreign Subsidiaries	**316,782**	190,446	103,947	205,659	181,482
Income Tax Expense	**128,161**	72,034	37,106	77,068	64,829
Minority Interest in Foreign Subsidiaries – (Expense)	**(785)**	(730)	(1,342)	(1,384)	(1,616)
Income Before Cumulative Effect of Changes in Accounting	**187,836**	117,682	65,499	127,207	115,037
Cumulative Effect of Changes in Accounting	**(8,892)**	—	—	—	—
Net Income Available for Common Stock	**$178,944**	$117,682	$65,499	$127,207	$115,037
Per Common Share Data					
Basic Earnings per Common Share	**$2.21** (1)	$1.47	$0.83	$1.63	$1.49
Diluted Earnings per Common Share	**$2.20** (1)	$1.46	$0.82	$1.61	$1.47
Dividends Declared	**$1.06**	$1.03	$0.99	$0.95	$0.92
Dividends Paid	**$1.05**	$1.02	$0.97	$0.94	$0.91
Dividend Rate at Year-End	**$1.08**	$1.04	$1.01	$0.96	$0.93
At September 30:					
Number of Common Shareholders	**19,217**	20,004	20,345	21,164	22,336
Net Property, Plant and Equipment *(Thousands)*					
Utility	**$1,036,432**	$960,015	$945,693	$939,753	$919,642
Pipeline and Storage	**705,927**	487,793	483,222	474,972	466,524
Exploration and Production	**925,833**	1,072,200	1,081,622	998,852	674,813
International	**219,199**	207,191	178,250	172,602	210,920
Energy Marketing	**171**	125	262	360	489
Timber	**87,600**	110,624	90,453	95,607	88,623
All Other	**22,042**	6,797	1,209	1,241	214
Corporate	**1,883**	—	2	4	7
Total Net Plant	**$2,999,087**	$2,844,745	$2,780,713	$2,683,391	$2,361,232
Total Assets *(Thousands)*	**$3,727,915**	$3,401,309	$3,445,231	$3,251,031	$2,842,586
Capitalization *(Thousands)*					
Comprehensive Shareholders' Equity	**$1,137,390**	$1,006,858	$1,002,655	$987,437	$939,293
Long-Term Debt, Net of Current Portion	**1,147,779**	1,145,341	1,046,694	953,622	822,743
Total Capitalization	**$2,285,169**	$2,152,199	$2,049,349	$1,941,059	$1,762,036

(1) Includes cumulative effect of changes in accounting of ($0.11) basic and diluted.

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



THE REVENUE DOLLAR – 2003



Results of Operation

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 units-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 pool of 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 (as adjusted for hedging) 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 amount of the ceiling can fluctuate significantly from period to period because of additions or subtractions to proved reserves and significant fluctuations in oil and gas prices. 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 at the end of any fiscal quarter, 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 non-cash impairments relating to its Canadian properties in 2003 and 2001. The impairments in 2003 amounted to $28.9 million (after tax) and resulted from downward revisions to crude oil reserves (related to the Canadian properties sold) as well as a decline in crude oil prices subsequent to March 31, 2003. The impairment in 2001 amounted to $104.0 million (after tax) and resulted from low oil and gas prices at September 30, 2001.

It is difficult to predict what factors could lead to future impairments under the SEC's full cost ceiling test. As discussed above, fluctuations or subtractions to proved reserves and significant fluctuations in oil and gas prices have an impact on the amount of the ceiling at any point in time.

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 ratesetting 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. For further discussion of the Company's regulatory assets and liabilities, refer to Item 8 at Note B - Regulatory Matters.

Accounting for Derivative Financial Instruments. The Company, in its Exploration and Production segment, Energy Marketing segment, Pipeline and Storage segment and All Other Category, 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 are categorized as price swap agreements, no cost collars, options and futures contracts. The Company, in its Pipeline and Storage segment, uses an interest rate collar to eliminate interest rate fluctuations on certain variable rate debt. 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. Refer to the "Market Risk Sensitive Instruments" section in Item 7, MD&A for further discussion of the Company's derivative financial instruments.

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

2003 Compared with 2002

The Company's earnings were $178.9 million in 2003 compared with earnings of $117.7 million in 2002. The increase in earnings of $61.2 million is primarily the result of higher earnings in the Timber, Utility, and Pipeline and Storage segments partially offset by lower earnings in the Energy Marketing segment and losses in the Exploration and Production and International segments, as shown in the table below. This earnings fluctuation is impacted by several events. In 2003, the Company's Timber segment completed the sale of approximately 70,000 acres of its timber property, recording an after tax gain of $102.2 million. Also in 2003, the Company's Exploration and Production segment completed the sale of the Company's Southeast Saskatchewan oil and gas properties in Canada, recording an after tax loss of $39.6 million. The Company's Exploration and Production segment also recorded after tax impairment charges of $28.9 million related to its Canadian oil and gas assets, which is discussed above under Critical Accounting Policies - Oil and Gas Exploration and Development Costs. Earnings for 2003 included an impairment in the amount of $8.3 million, representing the cumulative effect of a change in accounting for goodwill in the Company's International segment. Earnings for 2003 also included a reduction in the amount of $0.6 million, representing the cumulative effect of a change in accounting for plugging and abandonment costs in the Company's Exploration and Production segment. In 2002, earnings 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). For a more complete discussion of the cumulative effect of changes in accounting, refer to Note A - Summary of Significant Accounting Policies in Item 8 of this report.

2002 Compared with 2001

The Company's earnings were $117.7 million in 2002 compared with earnings of $65.5 million in 2001. Higher earnings in the Exploration and Production segment and the Energy Marketing segment were partially offset by lower earnings in the Utility and Pipeline and Storage segments. The All Other category also experienced a lower loss. As mentioned above, 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). 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), which is discussed above under Critical Accounting Policies - Oil and Gas Exploration and Development Costs. These events were the main reasons for lower 2002 earnings for the Pipeline and Storage segment and higher 2002 earnings for 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)	2003	2002	2001
Utility	**$56,808**	$49,505	$60,707
Pipeline and Storage	**45,230**	29,715	40,377
Exploration and Production	**(31,930)**	26,851	(32,284)
International	**(9,623)**	(4,443)	(3,042)
Energy Marketing	**5,868**	8,642	(3,432)
Timber	**112,450**	9,689	7,715
Total Reportable Segments	**178,803**	119,959	70,041
All Other	**193**	(885)	(4,277)
Corporate	**(52)**	(1,392)	(265)
Total Consolidated	**$178,944**	$117,682	$65,499

Utility

Revenues

UTILITY OPERATING REVENUES

Year Ended September 30 (Thousands)	2003	2002	2001
Retail Revenues:			
Residential	**$801,984**	$538,345	$875,050
Commercial	**137,905**	86,963	154,266
Industrial	**23,263**	18,332	29,110
	963,152	643,640	1,058,426
Off-System Sales	**107,220**	68,606	84,078
Transportation	**86,374**	83,267	89,037
Other	**6,237**	(1,292)	3,106
	$1,162,983	$794,221	$1,234,647

UTILITY THROUGHPUT – MILLION CUBIC FEET (MMCF)

Year Ended September 30	2003	2002	2001
Retail Sales:			
Residential	**76,449**	64,639	73,530
Commercial	**14,177**	11,549	13,831
Industrial	**3,537**	3,715	4,089
	94,163	79,903	91,450
Off-System Sales	**17,999**	21,541	12,736
Transportation	**64,232**	61,909	66,283
	176,394	163,353	170,469

2003 Compared with 2002

Operating revenues for the Utility segment increased $368.8 million in 2003 compared with 2002. This resulted from an increase in retail and off-system gas sales revenues of $319.5 million and $38.6 million, respectively. Transportation and other revenues also increased by $3.1 million and $7.5 million, respectively.

The increase in retail gas sales revenues for the Utility segment was largely a function of the recovery of higher gas costs (gas costs are recovered dollar for dollar in revenues), 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 colder weather, as shown in the table below. Off-system sales revenues increased because of higher gas prices, which more than offset lower volumes. However, due to profit sharing with retail customers, the margins resulting from off-system sales were minimal. Colder weather also caused transportation revenues and volumes to increase.

The increase in other operating revenues is largely related to a three-year rate settlement approved by the State of New York Public Service Commission (NYPSC) which ended on September 30, 2003. As part of the three-year rate settlement, Distribution Corporation was allowed to utilize certain refunds from upstream pipeline companies and certain other credits (referred to as the "cost mitigation reserve") to offset certain specific expense items. In 2003, Distribution Corporation reversed $7.6 million of the cost mitigation reserve into other operating revenues, compared to $2.2 million in 2002. In both years, the impact of reversing a portion of the cost mitigation reserve was offset by an equal amount of operation and maintenance expense and interest expense (thus there is no earnings impact). The increase in other operating revenues also reflects a $1.3 million decrease in refund provisions. In accordance with the three-year rate settlement discussed above, Distribution Corporation has been recording refund provisions related to a 50% sharing with customers of earnings over a predetermined amount. The refund provisions associated with this earnings sharing mechanism were $4.0 million and $5.3 million in 2003 and 2002, respectively.

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 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.

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 Segment's New York jurisdiction under the earnings sharing mechanism discussed above.

Partly offsetting the decreases to revenue discussed above was the positive impact of a lower bill credit in the Utility Segment'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.

Earnings

2003 Compared with 2002

The Utility segment's earnings in 2003 were $56.8 million, an increase of $7.3 million when compared with the earnings of $49.5 million in 2002. The major factor driving this increase was the impact of colder weather in the Utility segment's Pennsylvania jurisdiction, which contributed approximately $5.6 million to the increase in earnings. The impact of weather on the Utility segment's New York rate jurisdiction is tempered by a weather normalization clause (WNC). The WNC, 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 2003, the WNC reduced earnings by approximately $3.8 million (after tax) because it was colder than normal in the New York service territory. For 2002, the WNC preserved earnings of approximately $9.9 million (after tax) because it was warmer than normal in the New York service territory. The remainder of the increase was primarily attributable to lower interest expense, primarily on deferred gas costs (which declined approximately $1.0 million after tax).

2002 Compared with 2001

The Utility segment's earnings in 2002 were $49.5 million, a decrease of $11.2 million when compared with earnings of $60.7 million in 2001. Warmer weather in the Pennsylvania jurisdiction decreased earnings in 2002 by $3.7 million. Lower normalized usage per account (normalized usage excludes the impact of weather on consumption) across the Utility segment's service territory due to a downturn in the economy significantly decreased earnings in 2002 by $2.9 million. Also contributing to the decrease were several routine regulatory true-up adjustments associated with income taxes, lost and unaccounted for gas and interest expense, all of which decreased earnings by $6.5 million. In addition, 2001's earnings included $3.1 million (after tax) of income associated with stock appreciation rights and $4.2 million of after tax expense associated with early retirement offers in the Utility segment's New York and Pennsylvania jurisdictions. The impact of the refund provision discussed above was largely offset by lower operation and maintenance expenses, primarily labor. Earnings in 2002 benefitted from the impact of the lower bill credit ($5.0 million pre tax and $3.3 million after tax), discussed above.

In 2002, the WNC 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. In the Pennsylvania service territory, which does not have a WNC, weather during 2002 was 16.0% warmer than 2001 and 13.2% warmer than normal.

DEGREE DAYS

				Percent (Warmer) Colder Than	
Year Ended September 30		Normal	Actual	Normal	Prior Year
2003:	**Buffalo**	**6,815**	**7,137**	**4.7%**	**22.9%**
	Erie	**6,135**	**6,769**	**10.3%**	**26.9%**
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%

Purchased Gas

The cost of purchased gas is the Company's single largest operating expense. Annual variations in purchased gas costs are 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 satisfies 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 $6.94 per thousand cubic feet (Mcf) in 2003, an increase of 48% from the average cost of $4.68 per Mcf in 2002. The average cost of purchased gas in 2002 was 36% lower than the average cost of $7.35 per Mcf in 2001. 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)	**2003**	**2002**	**2001**
Firm Transportation	**$109,508**	$88,082	$91,611
Interruptible Transportation	**3,944**	3,315	1,917
	113,452	91,397	93,528
Firm Storage Service	**63,223**	62,733	61,559
Interruptible Storage Service	**36**	7	670
	63,259	62,740	62,229
Other	**24,709**	13,247	15,334
	$201,420	$167,384	$171,091

PIPELINE AND STORAGE THROUGHPUT – (MMCF)

Year Ended September 30	**2003**	**2002**	**2001**
Firm Transportation	**340,925**	290,507	304,183
Interruptible Transportation	**10,004**	7,315	17,372
	350,929	297,822	321,555

2003 Compared with 2002

Operating revenues for the Pipeline and Storage segment increased $34.0 million in 2003 as compared with 2002. For 2003, the acquisition of Empire State Pipeline (Empire) from Duke Energy Corporation on February 6, 2003 was a significant factor contributing to the revenue increase. For the period of February 6, 2003 to September 30, 2003, Empire recorded operating revenues of $20.9 million ($19.8 million in firm transportation revenues, $0.8 million in interruptible transportation revenues and $0.3 million in other revenues). Another factor contributing to the increase in operating revenues in the Pipeline and Storage segment was a $6.5 million increase in revenues from unbundled pipeline sales and open access transportation included in other revenues in the table above. The increase in revenues from unbundled pipeline sales and open access transportation primarily reflects higher natural gas commodity prices. While transportation volumes increased 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.

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.

Earnings

2003 Compared with 2002

The Pipeline and Storage segment's earnings in 2003 were $45.2 million, an increase of $15.5 million when compared with earnings of $29.7 million in 2002. A major factor in the earnings increase was the fact that 2002 included an after tax impairment charge of $9.9 million ($15.2 million pre tax) related to the Company's investment in Independence Pipeline Company (a partnership discontinued in 2002 that had proposed to construct and operate a 400-mile pipeline to transport natural gas from Defiance, Ohio to Leidy, Pennsylvania). Higher revenues from unbundled pipeline sales and open access transportation ($4.2 million after tax) were also a contributor to the earnings increase. The Empire acquisition in February 2003 contributed $3.0 million to 2003 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. As discussed above, the earnings for 2002 included a $9.9 million after tax impairment charge associated with the Company's investment in Independence Pipeline Company. Other factors contributing to the decrease included $4.2 million of earnings associated with stock appreciation rights recorded in 2001 and $2.6 million of earnings in 2001 associated with a termination fee received from a customer to cancel a long-term transportation contract. These decreases were partially offset by the fact that 2001 included $1.1 million of after tax expense associated with early retirement offers. Aside from the decrease in operation and maintenance expense associated with the early retirement offers in 2001, the Pipeline and Storage segment also experienced operation and maintenance expense savings in 2002 of $1.6 million after tax. A lower effective tax rate in 2002 compared to 2001 also helped to reduce the earnings decrease in 2002 by $3.2 million.

Exploration and Production

Revenues

EXPLORATION AND PRODUCTION OPERATING REVENUES

Year Ended September 30 (Thousands)	**2003**	**2002**	**2001**
Gas (after Hedging)	**$150,982**	$148,467	$171,045
Oil (after Hedging)	**147,101**	152,746	169,613
Gas Processing Plant	**28,879**	16,995	39,986
Other	**1,308**	6,627	17,700
Intrasegment Elimination (1)	**(22,956)**	(13,855)	(43,339)
	$305,314	$310,980	$355,005

(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	2003	2002	2001
Gas Production *(MMcf)*			
Gulf Coast	**18,441**	25,776	30,663
West Coast	**4,467**	4,889	4,383
Appalachia	**5,123**	4,402	4,142
Canada	**5,774**	6,387	1,816
	33,805	41,454	41,004
Oil Production *(Mbbl)*			
Gulf Coast	**1,473**	1,815	1,914
West Coast	**2,872**	3,004	2,875
Appalachia	**10**	9	7
Canada	**2,382**	2,834	3,061
	6,737	7,662	7,857

AVERAGE PRICES

Year Ended September 30	2003	2002	2001
Average Gas Price/Mcf			
Gulf Coast	**$5.41**	$2.89	$4.93
West Coast	**$5.01**	$2.86	$10.18
Appalachia	**$5.07**	$3.74	$5.03
Canada	**$4.67**	$2.29	$2.41
Weighted Average	**$5.18**	$2.88	$5.39
Weighted Average After Hedging (1)	**$4.47**	$3.58	$4.17
Average Oil Price/Barrel *(bbl)*			
Gulf Coast	**$29.17**	$22.83	$27.47
West Coast (2)	**$26.12**	$19.94	$24.06
Appalachia	**$28.77**	$23.76	$28.51
Canada	**$26.41**	$19.94	$24.29
Weighted Average	**$26.90**	$20.63	$24.99
Weighted Average After Hedging (1)	**$21.84**	$19.94	$21.59

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

2003 Compared with 2002

Operating revenues for the Exploration and Production segment decreased $5.7 million in 2003 as compared with 2002. Oil production revenue after hedging decreased $5.6 million due to a 925,000 barrel decline in production offset partly by higher weighted average prices after hedging ($1.90 per barrel). Gas production revenue after hedging increased $2.5 million. Increases in the weighted average price of gas after hedging ($0.89 per Mcf) more than offset an overall decrease in gas production. Most of the decrease in gas production occurred in the Gulf Coast of Mexico (a 7,335 MMcf decline). The Company had anticipated some of this decline in gas and oil production due to its plan to phase out of the Gulf Coast region. Other factors in the overall production decrease included an outside-operated offshore pipeline leak that required four key producing blocks to be shut-in for ten days, and a decline in drilling activity in Canada related to a decision to sell the Company's Southeast Saskatchewan oil properties, which is discussed below. Also, earlier in the year certain production in the Gulf Coast region was shut-in during Hurricane Lili and some of those wells are not expected to return to pre-hurricane production levels.* Gas processing plant revenues increased $11.9 million due to higher gas prices (because there is a similar increase in purchased gas expense, the impact on earnings is insignificant). Other revenues decreased $5.3 million largely due to the Exploration and Production segment experiencing negative mark-to-market adjustments on derivative financial instruments of $1.9 million during 2003 compared to positive mark-to-market adjustments on derivative financial instruments of $2.7 million in 2002.

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.

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 Corporation acquisition) (Player) offset partially by decreased production in the Gulf Coast region. As discussed above, the plan to phase out of the Gulf Coast region contributed to this decrease in oil and gas production. Gas processing plant revenues decreased $23.0 million due to significantly lower gas prices. Other revenues decreased $11.1 million largely due to mark-to-market gains on derivative financial instruments that were recorded in 2001.

Earnings

2003 Compared with 2002

The Exploration and Production segment experienced a loss of $31.9 million in 2003, a decrease of $58.8 million when compared with earnings of $26.9 million in 2002. The main reason for this decrease was the loss of $39.6 million recorded upon the sale of the Company's Southeast Saskatchewan oil and gas properties. During 2003, the Company reviewed the economics of its non-regulated business including certain oil and gas properties. The Southeast Saskatchewan properties were identified as a candidate for sale given their overall marginal contribution to earnings. The sale of these properties is expected to reduce the Exploration and Production segment's 2004 oil and gas production in Canada by approximately 2,000 Mbbl and 140 MMcf, respectively.* However, the impact to 2004 earnings is expected be minimal as lower production revenues will be offset by lower depletion expense.* After tax impairment charges of $28.9 million recorded in 2003 related to the Company's Canadian oil and gas assets also contributed to the decrease. Lower oil and gas revenues, as discussed above, decreased earnings by approximately $2.0 million. As an offset, the Exploration and Production segment experienced lower depletion expense of $2.9 million (attributable to the production decline) and lower general and administrative expenses of $2.1 million (attributable to cost-cutting efforts in Canada). Another offsetting factor was a lower effective income tax rate, which benefitted earnings by approximately $3.4 million.

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. A major reason for the increase was that 2001 earnings included a non-cash impairment of this segment's oil and gas assets totaling $104.0 million after tax, as previously discussed. Partially offsetting this positive impact was a decline in oil and gas revenues, which decreased earnings by approximately $25.7 million, due to lower weighted average commodity prices of crude oil and natural gas after hedging due to an increase in workover expenses ($1.65 per bbl and $0.59 per Mcf, respectively). Also, the decrease in other revenues associated with mark-to-market gains recorded in 2001, as discussed above, reduced earnings by $7.2 million. Higher lease operating expenses in the Gulf Coast region, due to an increase in workover expenses, also reduced earnings by approximately $3.0 million. The major workover expenditures occurred on Vermilion 252 and Eugene Island Block 264.

International

Revenues

INTERNATIONAL OPERATING REVENUES

Year Ended September 30 (Thousands)	2003	2002	2001
Heating	**$80,752**	$65,386	$69,072
Electricity	**29,386**	26,960	26,398
Other	**3,932**	2,969	2,440
	$114,070	$95,315	$97,910

INTERNATIONAL HEATING AND ELECTRIC VOLUMES

Year Ended September 30	2003	2002	2001
Heating Sales (Gigajoules) [1]	**8,714,806**	8,689,887	9,978,118
Electricity Sales (megawatt hours)	**973,968**	972,832	1,019,901

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

2003 Compared with 2002

Operating revenues for the International segment increased $18.8 million in 2003 as compared with 2002. Substantially all of this increase can be attributed to an increase in the value of the Czech koruna (CZK) compared to the U.S. dollar.

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 CZK compared to the U.S. dollar offset much of the impact of these negative factors.

Earnings

2003 Compared with 2002

The International segment experienced a loss of $9.6 million in 2003 compared with a loss of $4.4 million in 2002. This decrease can be attributed primarily to an $8.3 million impairment charge, resulting from the Company's change in accounting for goodwill. The Company's goodwill balance as of October 1, 2002 totaled $8.3 million and was related to the Company's investments in the Czech Republic, which are included in the International segment. In accordance with SFAS 142, "Goodwill and Other Intangible Assets" (SFAS 142), the Company stopped amortization of goodwill and tested its goodwill for impairment as of October 1, 2002. The Company used discounted cash flows to estimate the fair value of its goodwill at October 1, 2002 and determined that the goodwill had no remaining value. Based on projected restructuring in the Czech electricity market, the Company cannot be assured that the level of future cash flows from the Company's investments in the Czech Republic will attain the level that was originally forecasted.* In accordance with SFAS 142, this impairment was reported as a cumulative effect of a change in accounting in the quarter ending December 31, 2002. Partially offsetting the negative impact of the impairment, an increase in the value of the CZK compared to the U.S. dollar reduced the 2003 loss by approximately $1.0 million. Lower operating costs at the U.S. level (primarily lower project development costs and pension costs) further reduced the 2003 loss by approximately $1.0 million.

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 expense of approximately $4.0 million after tax, largely associated with the

Company's European power development projects, was the main factor in the higher loss in 2002. Lower interest expense of approximately $0.8 million after tax, and a higher effective tax rate (the impact of which was approximately $1.6 million) partially offset the impact of higher operation and maintenance expenses.

Energy Marketing

Revenues

ENERGY MARKETING OPERATING REVENUES

Year Ended September 30 (Thousands)	2003	2002	2001
Natural Gas (after Hedging)	**$304,390**	$151,219	$257,005
Electricity	**—**	—	1,362
Other	**270**	38	839
	$304,660	$151,257	$259,206

ENERGY MARKETING VOLUMES

Year Ended September 30	2003	2002	2001
Natural Gas – (MMcf)	**45,325**	33,042	36,753

2003 Compared with 2002

Operating revenues for the Energy Marketing segment increased $153.4 million in 2003, as compared with 2002. This increase primarily reflects higher gas sales revenue due to higher natural gas commodity prices. Higher volumes, which were principally the result of the addition of several high volume customers and colder weather, also contributed to the increase in operating revenues.

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.

Earnings

2003 Compared with 2002

The Energy Marketing segment earnings in 2003 were $5.9 million, a decrease of $2.7 million when compared with earnings of $8.6 million in 2002. This decrease primarily reflects lower margins on gas sales, primarily due to end of winter local distribution company operational constraints, combined with price volatility and weather related demand swings.

2002 Compared with 2001

The Energy Marketing segment earnings in 2002 were $8.6 million, an increase of $12.0 million when compared with a loss of $3.4 million in 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.

Timber

Revenues

TIMBER OPERATING REVENUES

Year Ended September 30 (Thousands)	2003	2002	2001
Log Sales	**$27,341**	$21,528	$23,460
Green Lumber Sales	**6,200**	6,567	5,597
Kiln Dry Lumber Sales	**21,814**	15,976	12,320
Other	**871**	3,336	3,537
	$56,226	$47,407	$44,914

TIMBER BOARD FEET

Year Ended September 30 (Thousands)	2003	2002	2001
Log Sales	**8,764**	8,174	8,839
Green Lumber Sales	**11,913**	12,878	10,332
Kiln Dry Lumber Sales	**13,300**	10,794	8,804
	33,977	31,846	27,975

2003 Compared with 2002

Operating revenues for the Timber segment increased $8.8 million in 2003, as compared with 2002. The increase can largely be attributed to higher sales of cherry veneer logs that command higher than average prices. Higher kiln dry lumber sales also contributed to the increase. Partially offsetting the increase in log sales and kiln dry lumber sales, other revenues decreased $2.5 million primarily because 2002 included a $2.4 million gain on the sale of standing timber.

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 logs. 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).

Earnings

2003 Compared with 2002

The Timber segment earnings in 2003 were $112.5 million, an increase of $102.8 million when compared with earnings of $9.7 million in 2002. The increase was primarily due to the sale of approximately 70,000 acres of timber properties on August 1, 2003 for approximately $186.0 million. As a result of the sale, the Company recorded an after tax gain of approximately $102.2 million. The Company decided to sell the timber property as a means of financing its acquisition of Empire, which is discussed below under "Capital Resources and Liquidity – Investing Cash Flow – Timber". Earnings from the Timber segment (exclusive of the $102.2 million after tax gain referred to above) are expected to decline in 2004 due to the fact that a greater portion of timber sales will be made from higher cost basis properties.* In prior fiscal years, sales from lower cost basis properties (a large portion of which were sold in 2003) represented a more significant percentage of total timber sales. After the August sale, the Company had approximately 87,000 acres of timber property remaining.

2002 Compared with 2001

The Timber segment earnings in 2002 were $9.7 million, an increase of $2.0 million when compared with earnings of $7.7 million in 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.

Corporate and All Other Operations

2003 Compared with 2002

Corporate and All Other operations had earnings of $0.1 million in 2003, an increase of $2.4 million when compared with a loss of $2.3 million in 2002. Earnings increased largely due to lower interest and operation costs.

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. The loss for 2001 included $0.7 million of earnings associated with stock appreciation rights and $3.5 million of after tax expense associated with a mark-to-market loss on natural gas inventory by Upstate, the Company's wholly-owned subsidiary which was engaged in wholesale natural gas marketing and other energy-related activities in 2001 (as noted in Item 1, Upstate is currently engaged primarily in the purchase, sale and transportation of landfill gas).

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 a 50% ownership interest 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 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.

2003 Compared with 2002

Income from unconsolidated subsidiaries (which represents the Company's equity method interest in the income or loss from its investment in unconsolidated subsidiaries) increased $0.3 million in 2003 compared with 2002. The improvement can largely be attributed to increases in income from the Company's investments in Seneca Energy ($0.8 million) and Model City ($0.3 million). Higher electric generation revenues and lower repair and maintenance expenditures on the generating engines were the main factors for the Seneca Energy and Model City increases. Partially offsetting these positive contributions, the ESNE investment experienced higher losses in 2003 compared to 2002 ($0.8 million). ESNE experienced lower electric generation revenues in 2003 compared to 2002, largely due to the fact that the spring and summer of 2003 was not as warm as the spring and summer of 2002. ESNE generates most of its electricity during the spring and summer months when electricty demand peaks for air conditioning requirements.

2002 Compared with 2001

Income from 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.

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 $0.1 million and $3.6 million in 2003 and 2002, respectively. The decrease in 2002 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 was able to market the excess capacity resulting from this termination.

Interest Charges

Interest on long-term debt increased $2.2 million in 2003 and $8.7 million in 2002. The increase in both years resulted mainly from a higher average amount of long-term debt outstanding which more than offset lower weighted average interest rates.

Other interest charges decreased $2.8 million in 2003 and $10.2 million in 2002. The decrease in both years was primarily the result of lower weighted average interest rates on short-term debt combined with a lower average amount of short-term debt outstanding.

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)	2003	2002	2001
Provided by Operating Activities	**$326.8**	$345.6	$414.0
Capital Expenditures	**(152.2)**	(232.4)	(292.7)
Investment in Subsidiaries, Net of Cash Acquired	**(228.8)**	—	(90.6)
Investment in Partnerships	**(0.4)**	(0.5)	(1.8)
Net Proceeds from Sale of Timber Properties	**186.0**	—	—
Net Proceeds from Sale of Oil and Gas Producing Properties	**78.5**	22.1	2.1
Other Investing Activities	**12.1**	5.0	(4.9)
Short-Term Debt, Net Change	**(147.6)**	(224.8)	(143.4)
Long-Term Debt, Net Change	**20.7**	139.6	187.2
Issuance of Common Stock	**17.0**	10.9	11.5
Dividends Paid on Common Stock	**(84.5)**	(81.0)	(76.7)
Effect of Exchange Rates on Cash	**1.6**	1.5	(0.6)
Net Increase (Decrease) in Cash and Temporary Cash Investments	**$29.2**	$(14.0)	$4.1

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 2003 and 2001), deferred income taxes, impairment of investment in partnership (in 2002), income or loss from unconsolidated subsidiaries net of cash distributions, minority interest in foreign subsidiaries, gain on sale of timber properties, loss on sale of oil and gas producing properties and cumulative effect of changes in accounting.

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 futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $326.8 million in 2003, a decrease of $18.8 million compared with the $345.6 million provided by operating activities in 2002. Higher working capital requirements in the Utility and Energy Marketing segments were the main reasons for this decrease. These decreases were partially offset by higher cash from operations in the Exploration and Production segment.

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 $381.4 million in 2003. The table below presents these expenditures:

Year Ended September 30, 2003 (Millions)	Capital Expenditures	Investments in Corporations or Partnerships	Total Expenditures For Long-Lived Assets
Utility	$49.9	$ —	$49.9
Pipeline and Storage	18.2	181.2 (1)	199.4
Exploration and Production	75.8	—	75.8
International	2.5	—	2.5
Energy Marketing	0.2	—	0.2
Timber	3.5	—	3.5
All Other and Corporate	2.1	48.0 (2)	50.1
	$152.2	$229.2	$381.4

(1) Investment amount is net of $8.0 million of cash acquired.
(2) Investment amount is net of $0.2 million of cash acquired.

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.

On February 6, 2003, the Company acquired the Empire State Pipeline (Empire) from a subsidiary of Duke Energy Corporation for $189.2 million in cash (including cash acquired) plus $57.8 million of project debt. The acquisition, which was made through Highland (a direct subsidiary having timber property and sawmill operations in New York and Pennsylvania), consisted of acquiring 100% of two companies. Each of these companies had 50% ownership of Empire, which is a joint venture. Empire's results of operations were incorporated into the Company's consolidated financial statements for the period subsequent to the completion of the acquisition on

February 6, 2003. Empire is a 157-mile, 24-inch pipeline that begins at the United States/Canadian border at 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 has almost all of its capacity under contract, with a substantial portion being long-term contracts. Refer to Item I, "The Pipeline and Storage Segment," for a discussion of Empire's transportation capacity. Empire delivers natural gas supplies to major industrial companies, utilities (including the Company's Utility segment) and power producers. Empire better positions 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 initial financing of the acquisition was accomplished through short-term borrowings. These short-term borrowings were repaid when the Company completed the sale of 70,000 acres of timber property on August 1, 2003. The sale of this timber property is discussed below under "Timber."

Exploration and Production

The Exploration and Production segment's capital expenditures included approximately $54.0 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 and fixed asset purchases. Of the $54.0 million discussed above, $30.8 million was spent on the Exploration and Production segment's Canadian properties. The Exploration and Production segment's capital expenditures also included approximately $21.8 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 2003, the Company spent $1.7 million (included in the amounts above) developing proved undeveloped reserves.

In September 2003, the Company sold its Southeast Saskatchewan oil and gas properties in Canada for approximately $76.0 million as previously discussed. The Company used the proceeds from the sale to repay short-term borrowings.

International

The majority of the International segment's capital expenditures were concentrated in improvements and replacements within the district heating and power generation plants in the Czech Republic.

Timber

The majority of the Timber segment's capital expenditures were for purchases of timber, as well as equipment and vehicles for this segment's sawmill and kiln operations.

As discussed above, the Company sold approximately 70,000 acres of its timber property located in various counties in Pennsylvania and Allegany County in New York in August 2003. The sale price was approximately $186.0 million. The Company recorded a pre-tax gain on this sale of approximately $168.8 million ($102.2 million after tax). The Company used the proceeds from this sale to repay short-term borrowings in connection with the Empire acquisition.

The remaining capital expenditures were for smaller purchases of land and timber for Seneca's timber operations as well as equipment for Highland's sawmill and kiln operations.

All Other and Corporate

The majority of the All Other and Corporate capital expenditures were for capital improvements to the Company's new corporate headquarters.

On June 3, 2003, the Company acquired for approximately $47.8 million in cash (including cash acquired of $0.2 million) all of the partnership interests in Toro Partners, L.P. (Toro), a limited partnership which owns and operates eight short-distance landfill gas pipeline companies that purchase, transport and resell landfill gas to customers in six states located primarily in the midwestern United States. Toro'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 3, 2003. The existing landfill gas purchase and sale agreements at these facilities remained in place. The Company believes there are opportunities for expansion at many of these locations.*

In May 2003, the Company made a capital contribution of $0.4 million to Seneca Energy. This capital contribution was related to the expansion of Seneca Energy's electric generation facilities to a new site at a landfill in Ontario County, New York.

Estimated Capital Expenditures

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

Year Ended September 30 (Millions)	2004	2005	2006
Utility	$53.0	$51.0	$51.0
Pipeline and Storage	27.0	29.0	26.0
Exploration and Production (1)	90.0	95.0	95.0
International	11.0	6.0	5.0
Timber	1.0	—	—
All Other	10.0	1.0	—
	$192.0	$182.0	$177.0

(1) Includes estimated expenditures for the years ended September 30, 2004, 2005 and 2006 of approximately $24 million, $17 million and $26 million, respectively, to develop proved undeveloped reserves.

Estimated capital expenditures for the Utility segment in 2004 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 2004 will be concentrated in the reconditioning of storage wells and the replacement of storage and transmission lines.*

The Company also continues to explore various opportunities to expand its capabilities to transport gas to the East Coast, either through the Supply Corporation or Empire systems or in partnership with others. This includes the Northwinds Pipeline that the Company and TransCanada PipeLines Limited have proposed. 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, 2003, the Company had incurred approximately $1.4 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 $350.0 million to $400.0 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 2004 for the Exploration and Production segment include approximately $38.2 million for Canada, $24.1 million for the Gulf Coast region ($23.5 million on the off-shore program in the Gulf of Mexico), $15.1 million for the West Coast region and $12.6 million for the Appalachian region.*

The estimated capital expenditures for the International segment in 2004 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 fired 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 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 2004 will be concentrated on the purchase and installation of a gas turbine and steam turbine by Horizon Power to create a 55-megawatt 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 February 2003, the Company issued $250.0 million of 5.25% long-term notes due in March 2013. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to approximately $248.5 million. The proceeds of this debt issuance were used to refund $150.0 million of 7.30% medium-term notes which matured in February 2003. The remaining proceeds were used to reduce short-term borrowings.

In March 2003, the Company redeemed $50.0 million of 8.48% medium-term notes at a redemption price of $52.5 million. The Company also redeemed $2.3 million of 6.214% medium-term notes in March 2003 at a redemption price of $2.25 million. The Company used short-term borrowings to redeem this debt.

Consolidated short-term debt decreased $147.2 million during 2003. Proceeds of $76.0 million received from the sale of the Company's southeast Saskatchewan oil and gas properties were used to reduce short-term debt, as previously discussed. The other major factors contributing to the fluctuation in short-term debt were the issuance of long-term debt in February 2003 and the redemption of long-term debt in March 2003, both of which are discussed above. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/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. At September 30, 2003, the Company had outstanding short-term notes payable to banks and commercial paper of $55.2 million, and $63.0 million, respectively. The Company has Securities and Exchange Commission (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. As for bank loans, the Company maintains a number of individual (bi-lateral) 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. Each of these credit lines, which aggregate to $415.0 million, 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.* 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 credit facility totaling $220.0 million. Of that amount, $110.0 million is committed to the Company through September 26, 2004, and $110.0 million is committed to the Company through September 30, 2005.

Under the Company's committed credit facility, the Company has agreed 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 thereafter. At September 30, 2003, the Company's debt to capitalization ratio (as calculated under the facility) was .57. The constraints specified in the committed credit facility would permit an additional $145.0 million in short-term and/or long-term debt to be outstanding before the Company's debt to capitalization ratio would exceed .625. If a downgrade in any of the Company's credit ratings were to occur, access to the commercial paper markets might not be possible.* However, the Company expects that it could borrow under its uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.*

Under the Company's existing indenture covenants, at September 30, 2003, the Company would have been permitted to issue up to a maximum of $289.0 million in additional long-term unsecured indebtedness at then current market interest rates (further limited by the debt to capitalization ratio constraints noted in the previous paragraph) in addition to being able to issue new indebtedness to replace maturing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands.*

The Company's indenture pursuant to which $624.0 million (or 45%) of the Company's long-term debt (as of September 30, 2003) was issued contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt to become due prior to its stated maturity, unless cured or waived.

The Company's committed $220.0 million, 364-day/3-year credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or its significant subsidiaries fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more or (ii) an event occurs that causes, or would permit the holders of such indebtedness to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2003, the Company had no debt outstanding under the committed credit facility.

The Company's embedded cost of long-term debt was 6.5% at September 30, 2003 and 7.0% at September 30, 2002. Refer to "Interest Rate Risk" in this Item for a more detailed break-down of the Company's embedded cost of long-term debt.

The Company also has authorization from the SEC, under the Holding Company Act, to issue long-term debt securities and equity securities in an aggregate amount of up to $1.5 billion during the order's authorization period, which commenced in November 2002 and extends to December 31, 2005. In January 2003, the Company registered $800.0 million of debt and equity securities under the Securities Act of 1933. After the February 2003 debt issuance discussed above, the Company has available capacity to issue an additional $550.0 million of debt and equity securities registered under the Securities Act of 1933. The Company may sell all or a portion of the remaining registered securities if warranted by market conditions and the Company's capital requirements. Any offer and sale of the above mentioned $550.0 million of debt and equity securities will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

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.

Off-Balance Sheet Arrangements

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 $28.9 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 unconsolidated subsidiaries, which are accounted for under the equity method, have capital leases of electric generating equipment having a remaining lease commitment of approximately $10.2 million. The Company has guaranteed 50%, or $5.1 million, of these capital lease commitments.

Contractual Obligations

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2003, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
(Millions)	2004	2005	2006	2007	2008	Thereafter	Total
Long-Term Debt	$241.7	$14.6	$13.9	$9.3	$209.3	$900.7	$1,389.5
Short-Term Bank Notes	$55.2	$ —	$ —	$ —	$ —	$ —	$55.2
Commercial Paper	$63.0	$ —	$ —	$ —	$ —	$ —	$63.0
Operating Lease Commitments	$7.4	$6.0	$4.5	$3.5	$2.7	$4.8	$28.9
Capital Lease Commitments	$0.8	$0.9	$1.1	$0.7	$0.7	$0.9	$5.1

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) NFR 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 (iii) 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.*

Other Matters

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 years, the Company anticipates that it will continue making contributions to the Retirement Plan.* During 2003, the Company contributed $35.1 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2004 will be in the range of $25.0 million to $35.0 million.* 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 or through short-term borrowings or through cash from operations.*

Market Risk Sensitive Instruments

Energy Commodity Price Risk

The Company, in its Exploration and Production segment, Energy Marketing segment, Pipeline and Storage segment, and All Other category, uses various derivative financial instruments (derivatives), including price swap agreements, no cost collars 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, 2003 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, 2003. At September 30, 2003, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2009.

NATURAL GAS PRICE SWAP AGREEMENTS

Expected Maturity Dates	2004	2005	2006	2007	2008	2009	Total
Notional Quantities (Equivalent Bcf)	8.4	0.9	1.2	1.2	1.1	0.3	13.1
Weighted Average Fixed Rate (per Mcf)	$3.87	$4.75	$4.85	$4.91	$4.94	$4.95	$4.24
Weighted Average Variable Rate (per Mcf)	$4.94	$4.67	$4.83	$4.78	$4.79	$4.83	$4.88

CRUDE OIL PRICE SWAP AGREEMENTS

	Expected Maturity Dates			
	2004	2005	2006	Total
Notional Quantities (Equivalent bbls)	1,734,000	375,000	75,000	2,184,000
Weighted Average Fixed Rate (per bbl)	$25.59	$24.83	$24.98	$25.44
Weighted Average Variable Rate (per bbl)	$27.46	$25.56	$25.17	$27.05

At September 30, 2003, the Company would have had to pay its respective counterparties an aggregate of approximately $8.8 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have had to pay an aggregate of approximately $3.4 million to its counterparties to terminate the crude oil price swap agreements outstanding at September 30, 2003.

At September 30, 2002, the Company had natural gas price swap agreements covering 18.5 Bcf at a weighted average fixed rate of $3.73 per Mcf. The Company also had crude oil price swap agreements covering 3,252,000 bbls at a weighted average fixed rate of $21.28 per bbl. Lower anticipated production in the Exploration and Production segment is the primary reason for the decrease in price swap agreements from September 2002 to September 2003.

The following table discloses 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, 2003, the Company had not entered into any natural gas or crude oil no cost collars extending beyond 2005.

NO COST COLLARS

	Expected Maturity Dates		
	2004	2005	Total
Natural Gas			
Notional Quantities (Equivalent Bcf)	3.0	0.7	3.7
Weighted Average Ceiling Price (per Mcf)	$7.15	$7.47	$7.21
Weighted Average Floor Price (per Mcf)	$3.51	$3.28	$3.46
Crude Oil			
Notional Quantities (Equivalent bbls)	1,185,000	105,000	1,290,000
Weighted Average Ceiling Price (per bbl)	$27.95	$28.56	$28.00
Weighted Average Floor Price (per bbl)	$23.81	$25.00	$23.91

At September 30, 2003, the Company would have had to pay an aggregate of approximately $0.4 million to terminate the natural gas no cost collars outstanding at that date. The Company would have had to pay an aggregate of approximately $1.1 million to terminate the crude oil no cost collars outstanding at that date.

At September 30, 2002, the Company had natural gas no cost collars covering 8.8 Bcf at 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 crude oil no cost collars covering 1,395,000 bbls at a weighted average floor price of $21.97 per bbl and a weighted average ceiling price of $26.29 per bbl. As discussed above, lower anticipated production in the Exploration and Production segment is the primary reason for the overall decrease in no cost collars from September 2002 to September 2003.

The following table discloses the net contract volumes purchased (sold), 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, 2003, the Company held no futures contracts with maturity dates extending beyond 2006.

FUTURES CONTRACTS

	Expected Maturity Dates			
	2004	2005	2006	Total
Net Contract Volumes Purchased (Sold) (Equivalent Bcf)	3.7	(0.1)	—*	3.6
Weighted Average Contract Price (per Mcf)	$5.65	$5.16	$4.23	$5.60
Weighted Average Settlement Price (per Mcf)	$5.35	$5.17	$4.76	$5.33

** The Company had two short (sold) futures contracts at September 30, 2003.*

At September 30, 2003, the Company would have received $1.7 million to terminate these futures contracts. At September 30, 2002, the Company had futures contracts covering 3.4 Bcf (net long position) at a weighted average contract price of $3.67 per Mcf.

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, 2003, the Company used seven counterparties for its over the counter derivative financial instruments. At September 30, 2003, no individual counterparty represented greater than 37% 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. This exchange rate risk to the Company's investments in the Czech Republic and Canada results in increases or decreases to the Cumulative Foreign Currency Translation Adjustment (CTA), a component of Accumulated Other Comprehensive Income/Loss on the Consolidated Balance Sheet. When the foreign currency increases in value in relation to the U.S. dollar, there is a positive adjustment to CTA. When the foreign currency decreases in value in relation to the U.S. dollar, there is a negative adjustment to the CTA.

Interest Rate Risk

The Company's exposure to interest rate risk arises primarily from its borrowing under short-term debt instruments. At September 30, 2003, these instruments consisted of domestic short-term bank loans and commercial paper totaling $118.2 million. The interest rate on these short-term bank loans and commercial paper approximated 1.2% at September 30, 2003.

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, 2003:

	Principal Amounts by Expected Maturity Dates						
(Millions of Dollars)	2004	2005	2006	2007	2008	Thereafter	Total
National Fuel Gas Company							
Long-Term Fixed Rate Debt	$225.0	$ —	$ —	$ —	$200.0	$896.4	$1,321.4
Weighted Average							
Interest Rate Paid	7.3%	—%	—%	—%	6.3%	6.4%	6.6%
Fair Value = $1,452.5 million							
Other Notes							
Long-Term Debt [1]	$16.7	$14.6	$13.9	$9.3	$9.3	$4.3	$68.1
Weighted Average							
Interest Rate Paid [2]	3.2%	3.3%	3.3%	1.8%	1.8%	1.8%	2.8%
Fair Value = $68.1 million							

(1) $54.4 million is variable rate debt; $13.7 million is fixed rate debt.
(2) Weighted average interest rate excludes the impact of an interest rate collar on $50.8 million of variable rate debt.

The Company uses an interest rate collar to eliminate interest rate fluctuations on $50.8 million of variable rate debt included in Other Notes in the table above. Under the interest rate collar the Company makes quarterly payments to (or receives payments from) another party when a variable rate falls below an established floor rate (the Company pays the counterparty) or exceeds an established ceiling rate (the Company receives payment from the counterparty). Under the terms of the collar, which extends until 2009, the variable rate is based on London InterBank Offered Rate. The floor rate of the collar is 5.15% and the ceiling rate is 9.375%. The Company would have had to pay $4.2 million to terminate the interest rate collar at September 30, 2003.

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) (collectively, "Parties") that established rates for the three-year period ending September 30, 2003. For a complete discussion of this Agreement, refer to "Rate Matters" in Item 7 of the Company's 2002 Form 10-K. On July 25, 2003, the Parties and other interests executed a settlement agreement ("Settlement") to extend the terms of the Agreement and Distribution Corporation's restructuring plan one year commencing October 1, 2003. The Settlement was approved by the NYPSC in an order issued on September 18, 2003. As approved, the Settlement continues existing base rates, and reduces the level above which earnings are shared 50/50 with customers from the current 11.5% return on equity to 11.0%. In addition, the Settlement increases the combined pension and other post employment benefit expense by $8.0 million, without a corresponding increase in revenues. Most other features of Distribution Corporation's service remain largely unchanged.

On September 20, 2001, the NYPSC issued an order under which Distribution Corporation was directed to show cause why an action for penalties of $19.0 million should not be commenced against it for alleged violations of consumer protection requirements. According to the NYPSC and intervenors, 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 and requested that the NYPSC either close (dismiss) the Show Cause proceeding based on the evidence presented in Distribution Corporation's response, or hold investigatory 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 and other matters. The adoption of a procedural schedule has been adjourned because the major parties to the proceeding are involved in settlement discussions. The Company believes and will continue to vigorously assert that the NYPSC's allegations lack merit. For a discussion of related legal matters, refer to Item 3, "Legal Proceedings."

Pennsylvania Jurisdiction

On April 16, 2003, Distribution Corporation filed a request with the Pennsylvania Public Utility Commission (PaPUC) to increase annual operating revenues by $16.5 million to cover increases in the cost of providing service, to be effective June 15, 2003. The PaPUC suspended the effective date to January 15, 2004. Distribution Corporation filed this request for several reasons including increases in the costs associated with Distribution Corporation's ongoing construction program as well as increases in uncollectible accounts and personnel expenses. On October 16, 2003, the parties reached a settlement of all issues. The settlement was submitted to the Administrative Law Judge, who thereafter, on November 17, 2003 issued a decision recommending adoption of the settlement. The settlement provides for a base rate increase of $3.5 million and authorizes deferral accounting for pension and OPEB expenses. The settlement was approved by the PaPUC on December 18, 2003, with rates scheduled to become effective January 15, 2004.

Pipeline and Storage

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

On November 25, 2003, the FERC issued Order 2004 "Standards of Conduct for Transmission Providers." Order 2004 regulates the conduct of transmission providers (such as Supply Corporation) with their energy affiliates. The FERC broadened the definition of "energy affiliates" to include any affiliate of a transmission provider if that affiliate engages in or is involved in transmission (gas or electric) transactions, or manages or controls transmission capacity, or buys, sells, trades or administers natural gas or electric energy or engages in financial transactions relating to the sale or transmission of natural gas or electricity. Order 2004 provides that companies may request waivers, and also provides an exemption from this rule for local distribution corporations that are affiliated with interstate pipelines, (such as Distribution Corporation), but the exemption is limited to local distribution corporations that do not make any off-system sales. Distribution Corporation currently does make such off-system sales and would like to continue doing so, whether by waiver, amendment or clarification of the new rule. Order 2004 also appears to define Empire State Pipeline as an energy affiliate of Supply Corporation, which is looking into both the possible costs of complying and the possibilities of a waiver, amendment or clarification that would allow Supply Corporation and Empire to operate together as they do now. Until there is further clarification from the FERC on the scope of these exemptions, the Company is unable to predict the impact Order 2004 will have on the Company.

Empire currently does not have a rate case on file with the NYPSC. Management will continue to monitor its financial position in the New York jurisdiction to determine the necessity of filing a rate case in the future.

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 $9.5 million to $10.5 million.* The minimum liability of $9.5 million has been recorded on the Consolidated Balance Sheet at September 30, 2003. Other than discussed in Note G (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 and Canada) 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 G - Commitments and Contingencies under the heading "Environmental Matters."

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.

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, without limitation, those which are designated with an asterisk ("*") and those which are identified by the use of the words "anticipates," "estimates," "expects," "intends," "plans,""predicts," "projects," and similar expressions, 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, including the occurrence of severe weather;
3. Changes in the availability and/or price of natural gas, oil and coal;
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 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

Financial Statements:

Report of Independent Auditors **62**
Consolidated Statements of Income and Earnings Reinvested in the Business, three years ended September 30, 2003 **63**
Consolidated Balance Sheets at September 30, 2003 and 2002 **64**
Consolidated Statement of Cash Flows, three years ended September 30, 2003 **66**
Consolidated Statement of Comprehensive Income, three years ended September 30, 2003 **67**
Notes to Consolidated Financial Statements **68**
Financial Statement Schedules:
For the three years ended September 30, 2003
II-Valuation and Qualifying Accounts **101**

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 auditors, 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 auditors have direct access to the Audit Committee and periodically meet with it without management representatives present.

Report of Independent Auditors

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, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2003, 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.

As discussed in Note A to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets, and No. 143, Accounting for Asset Retirement Obligations, on October 1, 2002.

PricewaterhouseCoopers LLP

Buffalo, New York
October 23, 2003

Consolidated Statements of Income and Earnings Reinvested in the Business

	Year Ended September 30 (Thousands of Dollars, Except Per Common Share Amounts)	2003	2002	2001
Income	**Operating Revenues**	**$2,035,471**	$1,464,496	$2,059,836
	Operating Expenses			
	Purchased Gas	**963,567**	462,857	1,002,466
	Fuel Used in Heat and Electric Generation	**61,029**	50,635	54,968
	Operation and Maintenance	**386,270**	394,157	364,318
	Property, Franchise and Other Taxes	**82,504**	72,155	83,730
	Depreciation, Depletion and Amortization	**195,226**	180,668	174,914
	Impairment of Oil and Gas Producing Properties	**42,774**	—	180,781
		1,731,370	1,160,472	1,861,177
	Gain on Sale of Timber Properties	**168,787**	—	—
	Loss on Sale of Oil and Gas Producing Properties	**(58,472)**	—	—
	Operating Income	**414,416**	304,024	198,659
	Other Income (Expense):			
	Income from Unconsolidated Subsidiaries	**535**	224	1,794
	Impairment of Investment in Partnership	**—**	(15,167)	—
	Other Income	**6,887**	7,017	10,639
	Interest Expense on Long-Term Debt	**(92,766)**	(90,543)	(81,851)
	Other Interest Expense	**(12,290)**	(15,109)	(25,294)
	Income Before Income Taxes and Minority Interest in Foreign Subsidiaries	**316,782**	190,446	103,947
	Income Tax Expense	**128,161**	72,034	37,106
	Minority Interest in Foreign Subsidiaries - (Expense)	**(785)**	(730)	(1,342)
	Income Before Cumulative Effect of Changes In Accounting	**187,836**	117,682	65,499
	Cumulative Effect of Changes in Accounting	**(8,892)**	—	—
	Net Income Available for Common Stock	**178,944**	117,682	65,499
Earnings Reinvested in the Business	Balance at Beginning of Year	**549,397**	513,488	525,847
		728,341	631,170	591,346
	Dividends on Common Stock	**85,651**	81,773	77,858
	Balance at End of Year	**$642,690**	$549,397	$513,488
	Earnings Per Common Share:			
	Basic:			
	Income Before Cumulative Effect of Changes in Accounting	**$2.32**	$1.47	$0.83
	Cumulative Effect of Changes in Accounting	**(0.11)**	—	—
	Net Income Available for Common Stock	**$2.21**	$1.47	$0.83
	Diluted:			
	Income Before Cumulative Effect of Changes in Accounting	**$2.31**	$1.46	$0.82
	Cumulative Effect of Changes in Accounting	**(0.11)**	—	—
	Net Income Available for Common Stock	**$2.20**	$1.46	$0.82
	Weighted Average Common Shares Outstanding:			
	Used in Basic Calculation	**80,808,794**	79,821,430	79,053,444
	Used in Diluted Calculation	**81,357,896**	80,534,453	80,361,258

See Notes to Consolidated Financial Statements

Consolidated Balance Sheets

Assets

At September 30 (Thousands of Dollars)	2003	2002
Property, Plant and Equipment	**$4,657,343**	$4,512,651
Less - Accumulated Depreciation, Depletion and Amortization	**1,658,256**	1,667,906
	2,999,087	2,844,745
Current Assets		
Cash and Temporary Cash Investments	**51,421**	22,216
Receivables – Net	**136,532**	95,510
Unbilled Utility Revenue	**27,443**	21,918
Gas Stored Underground	**89,640**	77,250
Materials and Supplies - at average cost	**32,311**	31,582
Unrecovered Purchased Gas Costs	**28,692**	12,431
Prepayments	**43,225**	41,354
Fair Value of Derivative Financial Instruments	**1,698**	3,807
	410,962	306,068
Other Assets		
Recoverable Future Taxes	**84,818**	82,385
Unamortized Debt Expense	**22,119**	20,635
Other Regulatory Assets	**49,616**	26,104
Deferred Charges	**7,528**	5,914
Other Investments	**64,025**	65,090
Investments in Unconsolidated Subsidiaries	**16,425**	16,753
Goodwill	**5,476**	8,255
Intangible Assets	**49,664**	11,451
Other	**18,195**	13,909
	317,866	250,496
	$3,727,915	$3,401,309

See Notes to Consolidated Financial Statements

Capitalization and Liabilities

At September 30 (Thousands of Dollars)	2003	2002
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value Authorized - 200,000,000 Shares; Issued and Outstanding - 81,438,290 Shares and 80,264,734 Shares, Respectively	**$81,438**	$80,265
Paid In Capital	**478,799**	446,832
Earnings Reinvested in the Business	**642,690**	549,397
Total Common Shareholder Equity Before Items Of Other Comprehensive Loss	**1,202,927**	1,076,494
Accumulated Other Comprehensive Loss	**(65,537)**	(69,636)
Total Comprehensive Shareholders' Equity	**1,137,390**	1,006,858
Long-Term Debt, Net of Current Portion	**1,147,779**	1,145,341
Total Capitalization	**2,285,169**	2,152,199
Minority Interest in Foreign Subsidiaries	**33,281**	28,785
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	**118,200**	265,386
Current Portion of Long-Term Debt	**241,731**	160,564
Accounts Payable	**125,779**	100,886
Amounts Payable to Customers	**692**	—
Other Accruals and Current Liabilities	**52,851**	46,402
Fair Value of Derivative Financial Instruments	**17,928**	31,204
	557,181	604,442
Deferred Credits		
Accumulated Deferred Income Taxes	**423,282**	356,220
Taxes Refundable to Customers	**13,519**	15,596
Unamortized Investment Tax Credit	**8,199**	8,897
Cost of Removal Regulatory Liability	**84,821**	—
Other Regulatory Liabilities	**69,867**	82,676
Pension Liability	**154,871**	75,116
Asset Retirement Obligation	**27,493**	—
Other Deferred Credits	**70,232**	77,378
	852,284	615,883
Commitments and Contingencies	**—**	—
	$3,727,915	$3,401,309

See Notes to Consolidated Financial Statements

Consolidated Statement of Cash Flows

	Year Ended September 30 (Thousands of Dollars)	2003	2002	2001
Operating Activities	Net Income Available for Common Stock	**$178,944**	$117,682	$65,499
	Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
	Gain on Sale of Timber Properties	**(168,787)**	—	—
	Loss on Sale of Oil and Gas Producing Properties	**58,472**	—	—
	Impairment of Oil and Gas Producing Properties	**42,774**	—	180,781
	Depreciation, Depletion and Amortization	**195,226**	180,668	174,914
	Deferred Income Taxes	**78,369**	62,013	(55,849)
	Impairment of Investment in Partnership	**—**	15,167	—
	Cumulative Effect of Changes in Accounting	**8,892**	—	—
	(Income) Loss from Unconsolidated Subsidiaries, Net of Cash Distributions	**703**	361	(1,199)
	Minority Interest in Foreign Subsidiaries	**785**	730	1,342
	Other	**11,289**	9,842	6,553
	Change in:			
	Receivables and Unbilled Utility Revenue	**(35,118)**	40,786	(2,277)
	Gas Stored Underground and Materials and Supplies	**(12,421)**	8,717	(37,054)
	Unrecovered Purchased Gas Costs	**(16,261)**	(8,318)	25,568
	Prepayments	**862**	(1,737)	(399)
	Accounts Payable	**20,435**	(24,025)	20,419
	Amounts Payable to Customers	**692**	(51,223)	41,640
	Other Accruals and Current Liabilities	**8,595**	(27,332)	13,969
	Other Assets	**(29,916)**	11,869	(33,169)
	Other Liabilities	**(16,698)**	10,350	13,289
	Net Cash Provided by Operating Activities	**326,837**	345,550	414,027
Investing Activities	Capital Expenditures	**(152,251)**	(232,368)	(292,706)
	Investment in Subsidiaries, Net of Cash Acquired	**(228,814)**	—	(90,567)
	Investment in Partnerships	**(375)**	(536)	(1,830)
	Net Proceeds from Sale of Timber Properties	**186,014**	—	—
	Net Proceeds from Sale of Oil and Gas Producing Properties	**78,531**	22,068	2,069
	Other	**12,065**	5,012	(4,892)
	Net Cash Used in Investing Activities	**(104,830)**	(205,824)	(387,926)
Financing Activities	Change in Notes Payable to Banks and Commercial Paper	**(147,622)**	(224,845)	(143,397)
	Net Proceeds from Issuance of Long-Term Debt	**248,513**	243,844	210,221
	Reduction of Long-Term Debt	**(227,826)**	(104,212)	(23,052)
	Proceeds from Issuance of Common Stock	**17,019**	10,915	11,545
	Dividends Paid on Common Stock	**(84,530)**	(80,974)	(76,671)
	Net Cash Used in Financing Activities	**(194,446)**	(155,272)	(21,354)
	Effect of Exchange Rates on Cash	**1,644**	1,535	(645)
	Net Increase (Decrease) in Cash and Temporary Cash Investments	**29,205**	(14,011)	4,102
	Cash and Temporary Cash Investments at Beginning of Year	**22,216**	36,227	32,125
	Cash and Temporary Cash Investments at End of Year	**$51,421**	$22,216	$36,227
	Supplemental Disclosure of Cash Flow Information			
	Cash Paid For:			
	Interest	**$104,452**	$100,397	$104,491
	Income Taxes	**$56,146**	$29,985	$77,662

See Notes to Consolidated Financial Statements

Consolidated Statement of Comprehensive Income

Year Ended September 30 (Thousands of Dollars)	2003	2002	2001
Net Income Available for Common Stock	**$178,944**	$117,682	$65,499
Other Comprehensive Income (Loss), Before Tax:			
Minimum Pension Liability Adjustment	**(86,170)**	(52,977)	—
Foreign Currency Translation Adjustment	**54,472**	24,278	(7,158)
Reclassification Adjustment for Realized Foreign Currency Translation (Gain) in Net Income	**(9,607)**	—	—
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	**2,419**	(2,086)	(712)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	**(47,777)**	(42,584)	58,355
Reclassification Adjustment for Realized (Gain) Loss on Derivative Financial Instruments in Net Income	**69,809**	(20,063)	83,218
Other Comprehensive Income (Loss), Before Tax:	**(16,854)**	(93,432)	133,703
Income Tax Benefit Related to Minimum Pension Liability Adjustment	**(30,159)**	(18,542)	—
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	**847**	(730)	(249)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	**(18,594)**	(17,341)	23,053
Reclassification Adjustment for Income Tax (Expense) Benefit on Realized (Gain) Loss on Derivative Financial Instruments In Net Income	**26,953**	(8,040)	32,032
Income Taxes – Net	**(20,953)**	(44,653)	54,836
Other Comprehensive Income (Loss), Before Cumulative Effect	**4,099**	(48,779)	78,867
Cumulative Effect of Change in Accounting, Net of Tax	**—**	—	(69,767)
Other Comprehensive Income (Loss), After Cumulative Effect	**4,099**	(48,779)	9,100
Comprehensive Income	**$183,043**	$68,903	$74,599

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

The Company's Utility and International segments record revenue 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. The Company's Pipeline and Storage and Energy Marketing segments record revenue as bills are rendered for service supplied on a calendar month basis. The Company's Timber segment records revenue on lumber and log sales as products are shipped.

The Company's Exploration and Production segment records revenue based on entitlement, which means that revenue is recorded based on the actual amount of gas or oil that is delivered to a pipeline and the Company's ownership interest in the producing well. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance.

Regulatory Mechanisms

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. Such amounts are generally recovered from (or passed back to) customers during the following fiscal year.

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

The impact of weather on revenues in the Utility segment's New York rate jurisdiction is tempered by a weather normalization clause (WNC), which covers the eight-month period from October through May. The

WNC 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. Since the Utility segment's Pennsylvania rate jurisdiction does not have a WNC, weather variations have a direct impact on the Pennsylvania rate jurisdiction's revenues.

In the Pipeline and Storage segment, the allowed rates that Supply Corporation bills its customers are based on a straight fixed-variable rate design, which allows recovery of all fixed costs in fixed monthly reservation charges. The allowed rates that Empire bills its customers are based on a modified fixed-variable rate design, which allows recovery of most fixed costs in fixed monthly reservation charges. To distinguish between the two rate designs, the modified fixed-variable rate design recovers return on equity and income taxes through variable charges whereas straight fixed-variable recovers all fixed costs, including return on equity and income taxes, through its monthly reservation charge. Because of the difference in rate design, changes in throughput due to weather variations do not have a significant impact on Supply Corporation's revenues but may have a significant impact on Empire's revenues.

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. The Company's capitalized costs exceeded the full-cost ceiling for the Company's Canadian properties at June 30, 2003, September 30, 2003 and September 30, 2001. The Company recognized impairments of $31.8 million and $11.0 million at June 30, 2003 and September 30, 2003, respectively. At September 30, 2001, the Company recognized an impairment of $180.8 million.

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

For oil and gas properties, depreciation, depletion and amortization is computed based on quantities produced in relation to proved reserves using the units of production method. The cost of unevaluated oil and gas properties is 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. For all other property, plant and equipment, depreciation, depletion and amortization is computed using the straight-line method in amounts sufficient to recover costs over the estimated service lives of property in service. The following is a summary of depreciable plant by segment:

As of September 30 (Thousands)	**2003**	**2002**
Utility	**$1,380,278**	$1,346,706
Pipeline and Storage	**928,415**	690,453
Exploration and Production	**1,673,827**	1,806,284
International	**349,133**	310,117
Energy Marketing	**1,159**	996
Timber	**96,315**	119,074
All Other and Corporate	**20,541**	7,115
	$4,449,668	$4,280,745

Average depreciation, depletion and amortization rates were are follows:

Year Ended September 30	**2003**	2002	2001
Utility	**2.8%**	2.8%	2.8%
Pipeline and Storage	**4.6%**	3.6%	3.6%
Exploration and Production, per Mcfe (1)	**$1.34**	$1.19	$1.12
International	**4.2%**	4.2%	5.1%
Energy Marketing	**10.9%**	16.4%	23.1%
Timber	**7.0%**	3.2%	3.2%
All Other and Corporate	**1.7%**	2.7%	8.0%

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note N - Supplementary Information for Oil and Gas Producing Properties, depletion of oil and gas producing properties amounted to $1.30, $1.16 and $1.08 per Mcfe of production in 2003, 2002 and 2001, respectively.

Cumulative Effect of Changes in Accounting

Effective October 1, 2002, the Company adopted the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). 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 estimated cost of retiring the asset as part of 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. In the Company's case, SFAS 143 changed the accounting for plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells. In prior fiscal years, the Company accounted for plugging and abandonment costs using the Securities and Exchange Commission's full cost accounting rules. SFAS 143 was calculated retroactively to determine the cumulative effect through October 1, 2002. This cumulative effect reduced earnings $0.6 million, net of income tax. If the new method of accounting for plugging and abandonment costs had been effective for 2002, there would not have been a material change to net income available for common stock. A reconciliation of the Company's asset retirement obligation calculated in accordance with SFAS 143 is shown below ($000s):

Balance at Adoption on October 1, 2002	$**36,090**
Liabilities Incurred During 2003	**242**
Liabilities Settled During 2003	**(13,227)**
Accretion Expense	**2,602**
Exchange Rate Impact	**1,786**
Balance at September 30, 2003	**$27,493**

In the Company's Utility and Pipeline and Storage segment, costs of removal are collected from customers through depreciation expense. These removal costs are not a legal retirement obligation in accordance with SFAS 143. Rather, they represent a regulatory liability. However, SFAS 143 requires that such costs of removal be reclassified from accumulated depreciation to other regulatory liabilities. At September 30, 2003, the cost of removal reclassified to other regulatory liabilities amounted to $84.8 million.

Effective October 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). In accordance with SFAS 142, the Company stopped amortization of goodwill and tested it for impairment as of October 1, 2002. The Company's goodwill balance as of October 1, 2002 totaled $8.3 million and is related to the Company's investments in the Czech Republic, which are included in the International segment. As a result of the impairment test, the Company recognized an impairment of $8.3 million. The Company used discounted cash flows to estimate the fair value of its goodwill and determined that the goodwill had no remaining value. Based on projected restructuring in the Czech electricity market, the Company cannot be assured that the level of future cash flows from the Company's investments in the Czech Republic will attain the level that was originally forecasted. In accordance with SFAS 142, this impairment has been reported as a cumulative effect of change in accounting. Goodwill amortization amounted to $0.6 million in both 2002 and 2001.

Effective October 1, 2000, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" 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 E - 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, 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 derivative 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 2003, 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 or interest expense 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 2003, 2002 or 2001.

Accumulated Other Comprehensive Income (Loss)

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

Year Ended September 30 (Thousands)	2003	2002
Minimum Pension Liability Adjustment	**$(90,446)**	$(34,435)
Cumulative Foreign Currency Translation Adjustment	**30,050**	(14,815)
Net Unrealized Loss on Derivative Financial Instruments	**(6,872)**	(20,545)
Net Unrealized Gain on Securities Available for Sale	**1,731**	159
Accumulated Other Comprehensive Loss	**$(65,537)**	$(69,636)

At September 30, 2003, it is estimated that $8.4 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 2004. As disclosed in Note E - Financial Instruments, the Company's derivative financial instruments extend out to 2009.

Gas Stored Underground - Current

In the Utility segment, gas stored underground - current in the amount of $75.2 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 2003, 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 $98.6 million at September 30, 2003. All other gas stored underground - current is carried at lower of cost or market on an average cost method.

Unamortized Debt Expense

Costs associated with the issuance of debt by the Company are deferred and amortized over the lives of the related debt. 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 $1.5 million and $0.4 million at September 30, 2003 and 2002, 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 2003, 2002 and 2001, 7,789,688, 5,260,633 and 1,290,747 stock options, respectively, were excluded as being antidilutive.

Stock-Based Compensation

The Company accounts for stock-based compensation using the intrinsic value method specified by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Under that method, no compensation expense was recognized for options granted under the plans for the years ended September 30, 2003, 2002 and 2001. Had compensation expense been determined based on fair value at the grant dates, which is the accounting treatment specified by SFAS 123, "Accounting for Stock-Based Compensation," the Company's net income and earnings per share would have been reduced to the pro forma amounts below:

Year Ended September 30 (Thousands, Except Per Share Amounts)	**2003**	**2002**	**2001**
Net Income Available for Common Stock As Reported	**$178,944**	$117,682	$65,499
Deduct:			
Total Compensation Expense Determined Based on Fair Value at the Grant Dates	**3,105**	4,641	6,391
Pro Forma Net Income Available for Common Stock	**$175,839**	$113,041	$59,108
Earnings Per Common Share:			
Basic - As Reported	**$2.21**	$1.47	$0.83
Basic - Pro Forma	**$2.18**	$1.42	$0.75
Diluted - As Reported	**$2.20**	$1.46	$0.82
Diluted - Pro Forma	**$2.16**	$1.40	$0.73

The weighted average fair value per share of options granted in 2003, 2002 and 2001 was $4.17, $4.32 and $5.25, 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	**2003**	**2002**	**2001**
Quarterly Dividend Yield	**1.10%**	1.07%	0.87%
Annual Standard Deviation (Volatility)	**22.24%**	21.83%	20.51%
Risk Free Rate	**3.33%**	4.88%	5.26%
Expected Term - in Years	**6.5**	5.5	5.0

NOTE B REGULATORY MATTERS

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

At September 30 (Thousands)	2003	2002
Regulatory Assets [1]:		
Recoverable Future Taxes (Note C)	**$84,818**	$82,385
Unrecovered Purchased Gas Costs (See Regulatory Mechanisms in Note A)	**28,692**	12,431
Unamortized Debt Expense (Note A)	**11,364**	10,021
Pension and Post-Retirement Benefit Costs [2] (Note F)	**47,750**	24,146
Other [2]	**1,866**	1,958
Total Regulatory Assets	**174,490**	130,941
Regulatory Liabilities:		
Cost of Removal Regulatory Liability (See Cumulative Effect Discussion in Note A)	**84,821**	—
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	**692**	—
New York Rate Settlements [3]	**30,900**	34,323
Taxes Refundable to Customers (Note C)	**13,519**	15,596
Pension and Post-Retirement Benefit Costs [3] (Note F)	**23,719**	39,946
Other [3]	**15,248**	8,407
Total Regulatory Liabilities	**168,899**	98,272
Net Regulatory Position	**$5,591**	$32,669

(1) The Company recovers the cost of its regulatory assets but, with the exception of Unrecovered Purchased Gas Costs, does not earn a return on them.
(2) Included in Other Regulatory Assets on the Consolidated Balance Sheets.
(3) 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% (11.0%, effective October 1, 2003) return on equity are to be shared equally between shareholders and customers. As a result of this sharing mechanism, the Company had liabilities of $11.4 million and $9.5 million at September 30, 2003 and 2002, respectively. Other aspects of the settlements include a special reserve of $5.4 million and $6.5 million at September 30, 2003 and 2002, respectively, to be applied against the Company's incremental costs resulting from the NYPSC's gas restructuring effort and a "cost mitigation reserve" of $8.2 million and $15.3 million at September 30, 2003 and 2002, respectively. The cost mitigation reserve 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 $5.9 million and $3.0 million at September 30, 2003 and 2002, 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)	2003	2002	2001
Operating Expenses:			
Current Income Taxes -			
Federal	**$37,336**	$7,743	$67,429
State	**11,990**	1,384	21,330
Foreign	**467**	894	4,196
Deferred Income Taxes -			
Federal	**53,310**	50,205	18,444
State	**12,983**	9,968	431
Foreign	**12,075**	1,840	(74,724)
	128,161	72,034	37,106
Other Income:			
Deferred Investment Tax Credit	**(693)**	(697)	(348)
Minority Interest in Foreign Subsidiaries	**(566)**	(277)	(614)
Cumulative Effect of Change in Accounting	**(354)**	—	—
Total Income Taxes	**$126,548**	$71,060	$36,144

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

Year Ended September 30 (Thousands)	2003	2002	2001
U.S.	**$383,695**	$180,349	$267,270
Foreign	**(78,202)**	8,394	(165,627)
	$305,493	$188,743	$101,643

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)	2003	2002	2001
Income Tax Expense, Computed at			
U.S. Federal Statutory Rate of 35%	**$106,923**	$66,060	$35,575
Increase (Reduction) in Taxes Resulting from:			
State Income Taxes	**16,232**	7,379	14,145
Foreign Tax Differential	**3,318**	(481)	(13,172)
Depreciation	**1,322**	1,744	1,790
Miscellaneous	**(1,247)**	(3,642)	(2,194)
Total Income Taxes	**$126,548**	$71,060	$36,144

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

At September 30 (Thousands)	**2003**	**2002**
Deferred Tax Liabilities:		
Property, Plant and Equipment	**$519,578**	$417,673
Other	**21,532**	27,930
Total Deferred Tax Liabilities	**541,110**	445,603
Deferred Tax Assets:		
Minimum Pension Liability Adjustment	**(48,701)**	(18,542)
Capital Loss Carryover	**(18,607)**	—
Other	**(56,877)**	(70,841)
	(124,185)	(89,383)
Valuation Allowance	**6,357**	—
Total Deferred Tax Assets	**(117,828)**	(89,383)
Total Net Deferred Income Taxes	**$423,282**	$356,220

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 $13.5 million and $15.6 million at September 30, 2003 and 2002, 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 $84.8 million and $82.4 million at September 30, 2003 and 2002, respectively.

Undistributed earnings of foreign subsidiaries of $57 million at September 30, 2003 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, the Company may be subject to U.S. income taxes and foreign withholding taxes, net of allowable foreign tax credits or deductions.

A capital loss carryover of $53 million exists at September 30, 2003, which expires if not utilized by September 30, 2008. Although realization is not assured, management estimates that a portion of the deferred tax asset associated with this carryover will be realized during the carryover period, and a valuation allowance is recorded for the remaining portion. Adjustments to the valuation allowance may be necessary in the future if estimates of capital gain income are revised.

NOTE D CAPITALIZATION AND SHORT-TERM BORROWINGS

SUMMARY OF CHANGES IN COMMON STOCK EQUITY

(Thousands, Except Per Share Amounts)	Common Stock Shares	Common Stock Amount	Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
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	(69,636)
Net Income Available for Common Stock				**178,944**	
Dividends Declared on Common Stock ($1.06 Per Share)				**(85,651)**	
Other Comprehensive Income, Net of Tax					**4,099**
Cancellation of Shares	**(3)**	**(3)**	**(63)**		
Common Stock Issued Under Stock and Benefit Plans	**1,176**	**1,176**	**32,030**		
Balance at September 30, 2003	**81,438**	**$81,438**	**$478,799**	**$642,690** (1)	**$(65,537)**

(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, 2003, $568.3 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.

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, 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
Granted in 2003	**233,500**	**$24.61**
Exercised in 2003 (1)	**(673,866)**	**$16.56**
Forfeited in 2003	**(123,800)**	**$23.55**
Outstanding at September 30, 2003	**14,065,338**	**$22.41**
Option shares exercisable at September 30, 2003	**12,420,444**	**$22.16**
Option shares available for future grant at September 30, 2003 (3)	**807,351**	

(1) In connection with exercising these options, 200,708, 43,834 and 78,850 shares were surrendered and canceled during 2003, 2002 and 2001, 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 following table summarizes information about options outstanding at September 30, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number Outstanding at 9/30/03	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 9/30/03	Weighted Average Exercise Price
$11.12 - $16.68	**1,161,104**	**1.6 years**	**$14.69**	**1,161,104**	**$14.69**
$16.69 - $22.24	**4,322,972**	**4.9 years**	**$20.36**	**4,138,572**	**$20.30**
$22.25 - $27.80	**8,581,262**	**6.5 years**	**$24.49**	**7,120,768**	**$24.46**

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 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	2003	2002	2001
Shares of Restricted Stock Awarded	—	100,000	4,000
Weighted Average Market Price of Stock on Award Date	—	$24.50	$27.80

As of September 30, 2003, 136,128 shares of non-vested restricted stock were outstanding. Vesting restrictions will lapse as follows: 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 $1.0 million, $0.7 million and $0.3 million for the years ended September 30, 2003, 2002 and 2001, respectively.

Redeemable Preferred Stock

As of September 30, 2003, 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)	2003	2002
Debentures [1]:		
7-3/4% due February 2004	**$125,000**	$125,000
Medium-Term Notes [1]:		
6.0% to 7.50% due August 2004 to June 2025	**849,000**	1,051,300
Notes [1]:		
5.25% to 6.50% due March 2013 to September 2022 [2]	**347,400**	97,700
	1,321,400	1,274,000
Other Notes:		
Secured [3]	**50,767**	—
Unsecured	**17,343**	31,905
Total Long-Term Debt	**1,389,510**	1,305,905
Less Current Portion	**241,731**	160,564
	$1,147,779	$1,145,341

(1) These debentures, medium-term notes and notes are unsecured.

(2) $97,400,000 of 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.

(3) These notes constitute "project financing" and are secured by the various project documentation and natural gas transportation contracts related to the Empire State Pipeline.

As of September 30, 2003, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $241.7 million in 2004, $14.6 million in 2005, $13.9 million in 2006, $9.3 million in 2007, $209.3 million in 2008 and $900.7 million thereafter.

Short-Term Borrowings

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 a number of individual (bi-lateral) 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. Each of these credit lines, which aggregate to $415.0 million, 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. 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 credit facility totaling $220.0 million. Of that amount, $110.0 million is committed to the Company through September 26, 2004, and $110.0 million is committed to the Company through September 30, 2005.

At September 30, 2003, the Company had outstanding short-term notes payable to banks and commercial paper of $55.2 million and $63.0 million, respectively. All of this debt was domestic. At September 30, 2002, the Company had outstanding notes payable to banks and commercial paper of $91.3 million (including $79.9 million in domestic debt and $11.4 million in foreign debt) and $174.1 million, respectively.

The weighted average interest rate on domestic notes payable to banks was 1.27% and 2.05% at September 30, 2003 and 2002, respectively. The interest rate on the foreign notes payable to banks was 3.64% at September 30, 2002. The weighted average interest rate on commercial paper was 1.18% and 2.04% at September 30, 2003 and 2002, respectively.

Debt Restrictions

Under the Company's committed credit facility, the Company has agreed that its debt to capitalization ratio (as calculated under that facility) 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 thereafter. At September 30, 2003, the Company's debt to capitalization ratio (as calculated under the facility) was .57. The constraints specified in the committed credit facility would permit an additional $145.0 million in short-term and/or long-term debt to be outstanding before the Company's debt to capitalization ratio would exceed .625. If a downgrade in any of the Company's credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its committed and uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company's existing indenture covenants, at September 30, 2003, the Company would have been permitted to issue up to a maximum of $289.0 million in additional long-term unsecured indebtedness at then current market interest rates (further limited by the debt to capitalization ratio constraints noted in the previous paragraph) in addition to being able to issue new indebtedness to replace maturing debt.

The Company's indenture pursuant to which $624.0 million (or 45%) of the Company's long-term debt (as of September 30, 2003) was issued contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest or any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt to become due prior to its stated maturity, unless cured or waived.

The Company's committed $220.0 million, 364-day/3-year credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or its significant subsidiaries fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more or (ii) an event occurs that causes, or would permit the holders of such indebtedness to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2003, the Company had no debt outstanding under the committed credit facility.

NOTE E 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)	2003 Carrying Amount	2003 Fair Value	2002 Carrying Amount	2002 Fair Value
Long-Term Debt	**$1,389,510**	**$1,520,606**	$1,305,905	$1,393,949

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 cost, which approximates 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 $53.5 million and $57.1 million at September 30, 2003 and 2002, respectively. The fair value of the equity mutual fund was $4.8 million and $3.8 million at September 30, 2003 and 2002, respectively. The gross unrealized loss on the equity mutual fund was $0.6 million and $1.5 million at September 30, 2003 and 2002, respectively. The fair value of the stock of an insurance company was $5.7 million and $4.2 million at September 30, 2003 and 2002, respectively. The gross unrealized gain on this stock was $3.2 million and $1.7 million at September 30, 2003 and 2002, 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 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." The majority of 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 and the All Other category. The Energy Marketing segment accounts for these derivative financial instruments as fair value hedges and uses them to hedge against falling prices, a risk to which they are exposed on their fixed price gas purchase commitments. At September 30, 2003, the Company had natural gas price swap agreements covering a notional amount of 13.1 Bcf extending through 2009 at a weighted average fixed rate of $4.24 per Mcf. Of this amount, 0.2 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $5.02 per Mcf. The remaining 12.9 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $4.22 per Mcf. The Company also had crude oil price swap agreements covering a notional amount of 2,184,000 bbls extending through 2006 at a weighted average fixed rate of $25.44 per bbl. At September 30, 2003, the Company would have had to pay a net $12.2 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, 2003, the Company had no cost collars on natural gas covering a notional amount of 3.7 Bcf extending through 2005 with a weighted average floor price of $3.46 per Mcf and a weighted average ceiling price of $7.21 per Mcf. The Company also had no cost collars on crude oil covering a notional amount of 1,290,000 bbls extending through 2005 with a weighted average floor price of $23.91 per bbl and a weighted average ceiling price of $28.00 per bbl. At September 30, 2003, the Company would have had to pay $1.5 million to terminate the no cost collars.

At September 30, 2003, the Company had long (purchased) futures contracts covering 11.4 Bcf of gas extending through 2005 at a weighted average contract price of $5.49 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 had to pay $1.8 million to terminate these futures contracts at September 30, 2003.

At September 30, 2003, the Company had short (sold) futures contracts covering 7.8 Bcf of gas extending through 2006 at a weighted average contract price of $5.76 per Mcf. Of this amount, 4.4 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 Exploration and Production segment and the All Other category. The remaining 3.4 Bcf is accounted for as fair value hedges, since these contracts hedge against falling prices, a risk to which the Energy Marketing segment is exposed on its gas storage inventory and fixed price gas purchase commitments. The Company would have received $3.5 million to terminate these futures contracts at September 30, 2003.

The Company may be exposed to credit risk on some of the derivative financial instruments discussed 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, 2003, the Company used seven counterparties for its over the counter derivative financial instruments. At September 30, 2003, no individual counterparty represented greater than 37% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company's total volumes hedged).

The Company uses an interest rate collar to eliminate interest rate fluctuations on certain variable rate debt in the Pipeline and Storage segment. Under the interest rate collar the Company makes quarterly payments (or receives payments from) another party when a variable rate falls below an established floor rate (the Company pays the counterparty) or exceeds an established ceiling rate (the Company receives payment from the counterparty). Under the terms of the collar, which extends until 2009, the variable rate is based on London InterBank Offered Rate. The floor rate of the collar is 5.15% and the ceiling rate is 9.375%. At September 30, 2003 the notional amount on the collar was $53.7 million. The Company would have had to pay $4.2 million to terminate the interest rate collar at September 30, 2003.

NOTE F 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. In addition, the Company has established 401(h) accounts for its Post-Retirement Plan. They are separate accounts in the Retirement Plan used to pay retiree medical benefits for the associated participants in the Retirement Plan. Contributions are tax-deductible when made and investments accumulate tax-free. 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 recovers certain 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, to the extent there is recovery in rates, 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. The regulatory treatment of a substantial amount of these regulatory assets and liabilities is governed by policy statements issued by the regulatory commissions having jurisdiction over the Utility and Pipeline and Storage segments. 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.

The expected returns on plan assets of the Retirement Plan and Post-Retirement Plan are applied to the market-related value of plan assets of the respective plans. For the Retirement Plan, the market-related value of assets recognizes the performance of its portfolio over five years and reduces the effects of short-term market fluctuations. The market-related value of Post-Retirement Plan assets is set equal to market value.

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)	2003	2002	2001
Change in Benefit Obligation			
Benefit Obligation at Beginning of Period	**$625,470**	$580,046	$535,894
Service Cost	**13,043**	11,639	11,550
Interest Cost	**40,967**	40,720	39,061
Amendments	**—**	420	2,343
Actuarial Loss	**51,302**	28,880	25,358
Benefits Paid	**(35,822)**	(36,235)	(34,160)
Benefit Obligation at End of Period	**$694,960**	$625,470	$580,046
Change in Plan Assets			
Fair Value of Assets at Beginning of Period	**$485,927**	$536,625	$569,936
Actual Return on Plan Assets	**6,145**	(29,898)	(19,248)
Employer Contribution	**35,083**	15,435	20,097
Benefits Paid	**(35,822)**	(36,235)	(34,160)
Fair Value of Assets at End of Period	**$491,333**	$485,927	$536,625
Reconciliation of Funded Status			
Funded Status	**$(203,627)**	$(139,543)	$(43,421)
Unrecognized Net Actuarial Loss	**222,250**	132,064	23,222
Unrecognized Transition Asset	**—**	(3,716)	(7,432)
Unrecognized Prior Service Cost	**10,274**	11,451	12,236
Prepaid (Accrued) Benefit Cost	**$28,897**	$ 256	$(15,395)
Accumulated Benefit Obligation	**$611,858**	$550,099	$510,155
Amounts Recognized in the Balance Sheets Consist of:			
Pension Liability	**$(154,871)**	$(75,116)	$(15,395)
Prepayments	**12,413**	10,944	—
Regulatory Assets	**21,934**	—	—
Intangible Assets	**10,274**	11,451	—
Accumulated Other Comprehensive Loss (Pre-Tax)	**139,147**	52,977	—
- Net Amount Recognized	**$28,897**	$256	$(15,395)

	2003	2002	2001
Weighted Average Assumptions as of September 30			
Discount Rate	**6.00%**	6.75%	7.25%
Expected Return on Plan Assets	**8.25%**	8.50%	8.50%
Rate of Compensation Increase	**6.11%**	6.11%	6.11%
Year Ended September 30 (Thousands)			
Components of Net Periodic Benefit Cost			
Service Cost	**$13,043**	$11,639	$11,550
Interest Cost	**40,967**	40,720	39,061
Expected Return on Plan Assets	**(47,260)**	(48,454)	(45,703)
Amortization of Prior Service Cost	**1,176**	1,205	1,050
Amortization of Transition Amount	**(3,716)**	(3,716)	(3,716)
Recognition of Actuarial (Gain) or Loss	**2,231**	(1,061)	(2,256)
Early Retirement Window	**—**	—	7,337
Net Amortization and Deferral for Regulatory Purposes	**3,781**	7,379	4,787
Net Periodic Benefit Cost	**$10,222**	$7,712	$12,110
Other Comprehensive Loss (Pre-Tax) Attributable to Change In Additional Minimum Liability Recognition	**$86,170**	$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, 2003 and 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 2003, 2002 and 2001 were to increase the Benefit Obligation by $57.4 million, $34.0 million and $15.6 million as of the end of each period, respectively.

In addition to the Retirement Plan discussed above, the Company also has a nonqualified benefit plan that covers a group of management employees designated by the Chief Executive Officer of the Company. This plan provides for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit cost associated with this plan was $5.1 million, $8.5 million and $6.1 million in 2003, 2002 and 2001, respectively. The benefit obligation for this plan was $40.0 million and $37.2 million at September 30, 2003 and 2002, respectively. The actuarial valuations for this plan were determined based on a discount rate of 6.0%, 6.75% and 7.25% as of September 30, 2003, 2002 and 2001, respectively; a rate of compensation increase of 8.11%, 8.11% and 7.32% as of September 30, 2003, 2002 and 2001, respectively; and an expected long-term rate of return on plan assets of 8.25%, 8.50% and 8.50% at September 30, 2003, 2002 and 2001, respectively. Under a provision of an agreement previously entered into between the Company and a participant of this plan, the participant has made an irrevocable election to receive a $23.0 million lump sum payment on January 3, 2004. When paid, this constitutes a partial settlement of the projected benefit obligations of this plan. Accordingly, the pro rata portion of this plan's unrecognized actuarial losses resulting from experience different from that assumed and from changes in assumptions is required to be recognized upon settlement. The estimated settlement loss is $10.5 million, before tax.

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)	2003	2002	2001
Change in Benefit Obligation			
Benefit Obligation at Beginning of Period	**$393,851**	$304,548	$266,460
Service Cost	**5,844**	4,658	4,234
Interest Cost	**26,124**	21,617	19,557
Plan Participants' Contributions	**682**	610	524
Amendments	**—**	—	33
Actuarial Loss	**57,983**	76,972	26,661
Benefits Paid	**(17,066)**	(14,554)	(12,921)
Benefit Obligation at End of Period	**$467,418**	$393,851	$304,548
Change in Plan Assets			
Fair Value of Assets at Beginning of Period	**$150,293**	$161,959	$176,357
Actual Return on Plan Assets	**390**	(18,181)	(19,685)
Employer Contribution	**32,195**	20,459	17,684
Plan Participants' Contributions	**682**	610	524
Benefits Paid	**(17,066)**	(14,554)	(12,921)
Fair Value of Assets at End of Period	**$166,494**	$150,293	$ 161,959
Reconciliation of Funded Status			
Funded Status	**$(300,923)**	$(243,558)	$(142,589)
Unrecognized Net Actuarial Loss	**212,242**	157,247	52,832
Unrecognized Transition Obligation	**71,272**	78,399	85,526
Unrecognized Prior Service Cost	**25**	30	33
Accrued Benefit Cost	**$(17,384)**	$ (7,882)	$ (4,198)

	2003	2002	2001
Weighted Average Assumptions as of September 30			
Discount Rate	**6.00%**	6.75%	7.25%
Expected Return on Plan Assets	**8.25%**	8.50%	8.50%
Rate of Compensation Increase	**6.11%**	6.11%	6.11%
Year Ended September 30 (Thousands)			
Components of Net Periodic Benefit Cost			
Service Cost	**$5,844**	$4,658	$4,234
Interest Cost	**26,124**	21,617	19,557
Expected Return on Plan Assets	**(12,268)**	(13,551)	(14,787)
Amortization of Prior Service Cost	**4**	4	—
Amortization of Transition Obligation	**7,127**	7,127	7,127
Amortization of (Gain) Loss	**14,866**	4,289	(374)
Net Amortization and Deferral for Regulatory Purposes	**(15,423)**	(729)	4,075
Net Periodic Benefit Cost	**$26,274**	$23,415	$19,832

The effects of the discount rate changes in 2003, 2002 and 2001 were to increase the Benefit Obligation by $45.1 million, $21.7 million and $9.8 million as of the end of each period, respectively.

The prescription drug aging assumptions and related factors were changed in 2003 to better reflect anticipated future experience. The effect of the changed prescription drug assumptions was to decrease the Accumulated Postretirement Benefit Obligation by $22.6 million.

Other actuarial experience increased the Accumulated Postretirement Benefit Obligation in 2003 by $35.1 million. In 2002, the impact of changes in health care trend assumptions to better reflect anticipated future experiences was an increase in the Accumulated Postretirement Benefit Obligation of $57.9 million.

The annual rate of increase in the per capita cost of covered medical care benefits was assumed to be 9.0% for 2001, 12.0% for 2002, 11.0% for 2003 and gradually decline to 5.5% by the year 2009 and remain level thereafter. The annual rate of increase for medical care benefits provided by healthcare maintenance organizations was assumed to be 9.0% in 2001, 12.0% in 2002, 11.0% in 2003 and gradually decline to 5.5% by the year 2009 and remain level thereafter. The annual rate of increase in the per capita cost of covered prescription drug benefits was assumed to be 13.0% for 2001, 15.0% for 2002, 13.5% for 2003 and gradually decline to 5.5% by the year 2009 and remain level thereafter. The annual rate of increase in the per capita Medicare Part B Reimbursement was assumed to be 9.0% for 2001, 8.0% for 2002, 7.0% for 2003 and gradually decline to 5.5% by the year 2009 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, 2003 would be increased by $68.7 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 2003 by $5.4 million. If the health care cost trend rates were decreased by 1% in each year, the Benefit Obligation as of October 1, 2003 would be decreased by $56.3 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 2003 by $4.0 million.

NOTE G COMMITMENTS AND CONTINGENCIES

Environmental Matters

The Company is subject to various federal, state and local laws and regulations (including those of the Czech Republic and Canada) 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 $9.5 million to $10.5 million. The minimum estimated liability of $9.5 million has been recorded on the Consolidated Balance Sheet at September 30, 2003. 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 five 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. A fourth site, which allegedly contains, among other things, manufactured gas plant waste, is in the investigation stage. Remediation has been completed at a fifth site, however, post-remedial construction care and maintenance is ongoing.

(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 $9.3 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. Substantially all of these contracts (representing 99% 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.

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 H 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. The Federal Energy Regulatory Commission (FERC) regulates the operations of Supply Corporation and the NYPSC regulates the operations of Empire, an intrastate pipeline which was acquired on February 6, 2003 and is discussed in Note J - Acquisitions. 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. Empire transports natural gas from the United States/Canadian border near Buffalo, New York into Central New York just north of Syracuse, New York. Empire transports gas to major industrial companies, utilities (including Distribution Corporation) and power producers. In June 2002, the Company wrote off its 33-1/3% equity method investment in Independence Pipeline Company, a partnership that had proposed to construct and operate a 400-mile pipeline to transport natural gas from Defiance, Ohio to Leidy, Pennsylvania. As shown in the table below, this impairment amounted to $15.2 million.

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 the Gulf Coast region of Texas and Louisiana and in the provinces of 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. On September 30, 2003, Seneca sold its southeast Saskatchewan oil and gas properties for a loss of $58.5 million, as shown in the table below. Proved reserves associated with the properties sold were 19.4 million barrels of oil and 0.3 Bcf of natural gas.

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. On August 1, 2003, the Company sold approximately 70,000 acres of timber property in Pennsylvania and New York. A gain of $168.8 million was recognized on the sale of this timber property, as shown in the table below.

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, 2003 (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	**$1,145,336**	**$106,499**	**$305,314**	**$114,070**	**$304,660**	**$56,226**	**$2,032,105**	**$3,366**	**$ —**	**$2,035,471**
Intersegment Revenues	**$17,647**	**$94,921**	**$ —**	**$ —**	**$ —**	**$ —**	**$112,568**	**$ —**	**$(112,568)**	**$ —**
Interest Expense	**$29,122**	**$14,000**	**$53,326**	**$8,700**	**$33**	**$2,507**	**$107,688**	**$521**	**$(3,153)**	**$105,056**
Depreciation, Depletion and Amortization	**$38,186**	**$35,940**	**$99,292**	**$13,910**	**$117**	**$7,543**	**$194,988**	**$238**	**$ —**	**$195,226**
Income Tax Expense	**$36,857**	**$30,863**	**$(17,537)**	**$876**	**$3,350**	**$72,692**	**$127,101**	**$279**	**$ 781**	**$128,161**
Significant Item: Gain on Sale of Timber Properties	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$168,787**	**$168,767**	**$ —**	**$ —**	**$168,787**
Significant Item: Loss on Sale of Oil and Gas Producing Properties	**$ —**	**$ —**	**$58,472**	**$ —**	**$ —**	**$ —**	**$58,472**	**$ —**	**$ —**	**$58,472**
Significant Non-cash Item: Impairment of Oil and Gas Producing Properties	**$ —**	**$ —**	**$42,774**	**$ —**	**$ —**	**$ —**	**$42,774**	**$ —**	**$ —**	**$42,774**
Segment Profit (Loss): Income Before Cumulative Effect of Changes in Accounting	**$56,808**	**$45,230**	**$(31,293)**	**$(1,368)**	**$5,868**	**$112,450**	**$187,695**	**$ 193**	**$ (52)**	**$187,836**
Expenditures for Additions to Long-Lived Assets	**$49,944**	**$199,327**	**$75,837**	**$2,499**	**$164**	**$3,493**	**$331,264**	**$48,293 (1)**	**$1,883**	**$381,440**
At September 30, 2003 (Thousands)										
Segment Assets	**$1,413,858**	**$812,435**	**$969,512**	**$254,937**	**$54,134**	**$125,915**	**$3,630,791**	**$77,195**	**$19,929**	**$3,727,915**

(1) Amount includes the acquisition of all of the partnership interests in Toro Partners, LP and is discussed in Note J - Acquisitions.

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

GEOGRAPHIC INFORMATION

For the Year Ended September 30 (Thousands)	2003	2002	2001
Revenues from External Customers (1):			
United States	**$1,818,980**	$1,293,239	$1,887,958
Czech Republic	**114,070**	95,315	97,910
Canada	**102,421**	75,942	73,968
	$2,035,471	$1,464,496	$2,059,836
At September 30 (Thousands)			
Long-Lived Assets:			
United States	**$2,982,301**	$2,624,810	$2,645,429
Czech Republic	**219,695**	216,044	187,961
Canada	**116,655**	258,196	257,939
	$3,318,651	$3,099,050	$3,091,329

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

NOTE | 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.

A summary of the Company's investments in unconsolidated subsidiaries at September 30, 2003 and 2002 is as follows:

At September 30 (Thousands)	**2003**	**2002**
ESNE	**$11,113**	$12,522
Seneca Energy	**4,445**	3,625
Model City	**867**	606
	$16,425	$16,753

NOTE J ACQUISITIONS

On February 6, 2003, the Company acquired Empire from a subsidiary of Duke Energy Corporation for $189.2 million in cash (including cash acquired) plus $57.8 million of project debt. Empire's results of operations were incorporated into the Company's consolidated financial statements for the period subsequent to the completion of the acquisition on February 6, 2003. Empire is a 157-mile, 24-inch pipeline that begins at the United States/Canadian border at 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 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. The Company believes that the acquisition of Empire better positions 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. Details of the acquisition are as follows (all figures in thousands):

Assets Acquired (see Condensed Balance Sheet below)	**$257,397**
Liabilities Assumed (see Condensed Balance Sheet below)	**(68,192)**
Cash Acquired at Acquisition	**(8,053)**
Cash Paid, Net of Cash Acquired	**$181,152**
Condensed Balance Sheet:	
Property, Plant and Equipment	**$220,792**
Current Assets	**14,984**
Goodwill	**5,476**
Intangible Assets (see Note K)	**8,580**
Other Assets	**7,565**
Total Assets	**$257,397**
Equity	**$189,205**
Long-Term Debt, Net of Current Portion	**48,433**
Total Capitalization	**237,638**
Current Liabilities	**15,265**
Other Liabilities	**4,494**
Total Capitalization and Liabilities	**$257,397**

On June 3, 2003, the Company acquired for approximately $47.8 million in cash (including cash acquired) all of the partnership interests in Toro Partners, L.P. (Toro), which owns and operates eight short-distance landfill gas pipeline companies that purchase, transport and resell landfill gas to customers in six states located primarily in the midwestern United States. Toro'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 3, 2003. The existing landfill gas purchase and sale agreements at these facilities remained in place. The Company believes there are opportunities for expansion at many of these locations. The acquisition consisted of approximately $15.3 million in property, plant and equipment, $31.9 million in intangible assets (as discussed in Note K), $1.1 million of current assets and $0.5 million of current liabilities. Details of the acquisition are as follows (all figures in thousands):

Assets Acquired	**$48,319**
Liabilities Assumed	**(497)**
Cash Acquired at Acquisition	**(160)**
Cash Paid, Net of Cash Acquired	**$47,662**

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. Player's name has been changed to Seneca Energy Canada, Inc.

NOTE K INTANGIBLE ASSETS

As a result of the Empire and Toro acquisitions discussed in Note J - Acquisitions, the Company acquired certain intangible assets during 2003. In the case of the Empire acquisition, the intangible assets represent the fair value of various long-term transportation contracts with Empire's customers. In the case of the Toro acquisition, the intangible assets represent the fair value of various long-term gas purchase contracts with the various landfills. These intangible assets are being amortized over the lives of the transportation and gas purchase contracts with no residual value at the end of the amortization period. The weighted-average amortization period for the gross carrying amount of the transportation contracts is 7 years. The weighted-average amortization period for the gross carrying amount of the gas purchase contracts is 20 years. Details of these intangible assets are as follows:

At September 30, 2003 (Thousands)	**Gross Carrying Amount**	**Accumulated Amortization**
Long-Term Transportation Contracts	**$ 8,580**	**$(713)**
Long-Term Gas Purchase Contracts	**31,864**	**(341)**
	$40,444	**$(1,054)**
Aggregate Amortization Expense For the Year Ended September 30, 2003		**$1,054**

Amortization expense for the transportation contracts is estimated to be $1.1 million annually for 2004, 2005, 2006, 2007 and 2008. Amortization expense for the gas purchase contracts is estimated to be $1.6 million annually for 2004, 2005, 2006, 2007 and 2008.

At September 30, 2003 and 2002, the Company also has recorded intangible assets of $10.3 million and $11.5 million, respectively, related to its Retirement Plan, as discussed in Note F - Retirement Plan and Other Post-Retirement Benefits.

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	Net Income Available for Common Stock	Earnings (Loss) Per Common Share Basic	Earnings (Loss) Per Common Share Diluted
2003	*(Thousands, except per common share amounts)*				
9/30/2003	**$297,170**	**$122,674**	**$58,146** (1)	**$0.71**	**$0.71**
6/30/2003	**$449,530**	**$ 35,411**	**$ 2,219** (2)	**$0.03**	**$0.03**
3/31/2003	**$809,065**	**$156,703**	**$80,538**	**$1.00**	**$0.99**
12/31/2002	**$479,706**	**$ 99,628**	**$38,041** (3)	**$0.47**	**$0.47**
2002	*(Thousands, except per common share amounts)*				
9/30/2002	$244,610	$ 28,268	$ 4,875	$0.06	$0.06
6/30/2002	$350,123	$ 71,113	$17,676 (4)	$0.22	$0.22
3/31/2002	$477,436	$123,136	$61,924	$0.78	$0.77
12/31/2001	$392,327	$ 81,507	$33,207	$0.42	$0.41

(1) Includes a gain of $102.2 million from the sale of timber properties, a loss of $39.6 million related to the sale of oil and gas properties and expense of $6.3 million related to the impairment of oil and gas producing properties.
(2) Includes expense of $22.6 million related to the impairment of oil and gas producing properties.
(3) Includes expense of $8.3 million related to the cumulative effect of change in accounting (SFAS 142) and an expense of $0.6 million due to the cumulative effect of change in accounting (SFAS 143).
(4) Includes expense of $9.9 million related to the impairment of investment in partnership.

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

At September 30, 2003, there were 19,217 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 and Short-Term Borrowings. The quarterly price ranges (based on intra-day prices) and quarterly dividends declared for the fiscal years ended September 30, 2003 and 2002, are shown below:

Quarter Ended	Price Range High	Price Range Low	Dividend Declared
2003			
9/30/2003	**$27.51**	**$22.51**	**$.270**
6/30/2003	**$26.90**	**$21.60**	**$.270**
3/31/2003	**$22.25**	**$18.97**	**$.260**
12/31/2002	**$21.86**	**$17.95**	**$.260**
2002			
9/30/2002	$22.84	$15.61	$ .260
6/30/2002	$24.98	$21.38	$ .260
3/31/2002	$25.70	$22.00	$.2525
12/31/2001	$24.95	$21.95	$.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)	2003	2002
Proved Properties	**$1,628,995**	$1,779,962
Unproved Properties	**30,955**	50,925
	1,659,950	1,830,887
Less - Accumulated Depreciation, Depletion and Amortization	**763,258**	776,477
	$896,692	$1,054,410

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, 2003:

	Total as of September 30,	Year Costs Incurred			
(Thousands)	2003	2003	2002	2001	Prior
Acquisition Costs	**$30,955**	**$8,129**	$5,102	$7,861	$9,863

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

Year Ended September 30 (Thousands)	2003	2002	2001
United States			
Property Acquisition Costs:			
Proved	**$(13)**	$9,316	$1,713
Unproved	**1,920**	698	15,296
Exploration Costs	**17,947**	25,583	42,338
Development Costs	**23,649**	51,792	88,987
	43,503	87,389	148,334
Canada			
Property Acquisition Costs:			
Proved	**181**	(536)	115,643
Unproved	**6,217**	2,804	2,612
Exploration Costs	**6,641**	8,779	8,523
Development Costs	**17,745**	15,332	36,554
	30,784	26,379	163,332
Total			
Property Acquisition Costs: (1)			
Proved	**168**	8,780	117,356
Unproved	**8,137**	3,502	17,908
Exploration Costs	**24,588**	34,362	50,861
Development Costs	**41,394**	67,124	125,541
	$74,287	$113,768	$311,666

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

For the years ended September 30, 2003, 2002, and 2001, the Company spent $1.7 million, $18.2 million and $41.1 million, respectively, developing proved undeveloped reserves.

RESULTS OF OPERATIONS FOR PRODUCING ACTIVITIES

Year Ended September 30 (Thousands, Except Per Mcfe Amounts)	**2003**	**2002**	**2001**
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $69, $43 and $4, respectively)	**$148,104**	$104,954	$216,729
Oil, Condensate and Other Liquids	**118,277**	101,549	121,973
Total Operating Revenues [1]	**266,381**	206,503	338,702
Production/Lifting Costs	**39,162**	42,956	37,068
Depreciation, Depletion and Amortization ($1.29, $1.25 and $1.13 per Mcfe of production)	**70,127**	80,142	76,686
Income Tax Expense	**63,398**	30,253	83,649
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	**93,694**	53,152	141,299
Canada			
Operating Revenues:			
Natural Gas	**26,992**	14,621	4,379
Oil, Condensate and Other Liquids	**62,908**	56,511	74,349
Total Operating Revenues [1]	**89,900**	71,132	78,728
Production/Lifting Costs	**33,038**	30,109	27,089
Depreciation, Depletion and Amortization ($1.30, $0.93 and $0.93 per Mcfe of production)	**26,165**	21,707	18,719
Impairment of Oil and Gas Producing Properties [2]	**42,774**	—	180,781
Income Tax Expense (Benefit)	**(3,069)**	4,672	(63,795)
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	**(9,008)**	14,644	(84,066)
Total			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $69, $43 and $4, respectively)	**175,096**	119,575	221,108
Oil, Condensate and Other Liquids	**181,185**	158,060	196,322
Total Operating Revenues [1]	**356,281**	277,635	417,430
Production/Lifting Costs	**72,200**	73,065	64,157
Depreciation, Depletion and Amortization ($1.30, $1.16 and $1.08 per Mcfe of production)	**96,292**	101,849	95,405
Impairment of Oil and Gas Producing Properties [2]	**42,774**	—	180,781
Income Tax Expense	**60,329**	34,925	19,854
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	**$84,686**	$67,796	$57,233

(1) Exclusive of hedging gains and losses. See further discussion in Note E - 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					
	U.S.					
	Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada	Total Company
Proved Developed and Undeveloped Reserves:						
September 30, 2000	113,402	110,364	74,744	298,510	3,157	301,667
Extensions and Discoveries	25,363	2,021	8,576	35,960	15,681	51,641
Revisions of Previous Estimates	(12,178)	(9,914)	(721)	(22,813)	(34)	(22,847)
Production	(30,663)	(4,383)	(4,142)	(39,188)	(1,816)	(41,004)
Sales of Minerals in Place	(6,066)	—	—	(6,066)	(280)	(6,346)
Purchases of Minerals in Place and Other	—	410	—	410	38,859	39,269
September 30, 2001	89,858	98,498	78,457	266,813	55,567	322,380
Extensions and Discoveries	6,530	5,770	4,242	16,542	20,263	36,805
Revisions of Previous Estimates	1,613	(26,063)	342	(24,108)	(20,676)	(44,784)
Production	(25,776)	(4,889)	(4,402)	(35,067)	(6,387)	(41,454)
Sales of Minerals in Place	(14,361)	—	(365)	(14,726)	—	(14,726)
Purchases of Minerals in Place and Other	—	—	—	—	—	—
September 30, 2002	57,864	73,316	78,274	209,454	48,767	258,221
Extensions and Discoveries	**10,538**	**—**	**5,844**	**16,382**	**11,641**	**28,023**
Revisions of Previous Estimates	**(2,278)**	**1,213**	**2,224**	**1,159**	**(2,211)**	**(1,052)**
Production	**(18,441)**	**(4,467)**	**(5,123)**	**(28,031)**	**(5,774)**	**(33,805)**
Sales of Minerals in Place	**—**	**—**	**—**	**—**	**(270)**	**(270)**
Purchases of Minerals in Place and Other	**—**	**—**	**—**	**—**	**—**	**—**
September 30, 2003	**47,683**	**70,062**	**81,219**	**198,964**	**52,153**	**251,117**
Proved Developed Reserves:						
September 30, 2000	107,921	44,585	74,744	227,250	3,157	230,407
September 30, 2001	87,893	47,442	78,457	213,792	53,463	267,255
September 30, 2002	57,274	57,286	78,273	192,833	39,253	232,086
September 30, 2003	**45,402**	**54,180**	**81,218**	**180,800**	**42,745**	**223,545**

	Oil Mbbl					
	U.S.					
	Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada	Total Company
Proved Developed and Undeveloped Reserves:						
September 30, 2000	8,488	68,944	79	77,511	42,186	119,697
Extensions and Discoveries	393	531	—	924	3,625	4,549
Revisions of Previous Estimates	12	1,720	5	1,737	(5,396)	(3,659)
Production	(1,914)	(2,875)	(7)	(4,796)	(3,061)	(7,857)
Sales of Minerals in Place	(685)	—	—	(685)	(80)	(765)
Purchases of Minerals in Place and Other	—	104	—	104	3,259	3,363
September 30, 2001	6,294	68,424	77	74,795	40,533	115,328
Extensions and Discoveries	57	1,360	20	1,437	586	2,023
Revisions of Previous Estimates	781	129	6	916	(10,278)	(9,362)
Production	(1,815)	(3,004)	(9)	(4,828)	(2,834)	(7,662)
Sales of Minerals in Place	(200)	—	—	(200)	(410)	(610)
Purchases of Minerals in Place and Other	—	—	—	—	—	—
September 30, 2002	5,117	66,909	94	72,120	27,597	99,717
Extensions and Discoveries	**104**	**—**	**46**	**150**	**729**	**879**
Revisions of Previous Estimates	**(365)**	**(185)**	**8**	**(542)**	**(4,119)**	**(4,661)**
Production	**(1,473)**	**(2,872)**	**(10)**	**(4,355)**	**(2,382)**	**(6,737)**
Sales of Minerals in Place	**—**	**—**	**—**	**—**	**(19,434)**	**(19,434)**
Purchases of Minerals in Place and Other	**—**	**—**	**—**	**—**	**—**	**—**
September 30, 2003	**3,383**	**63,852**	**138**	**67,373**	**2,391**	**69,764**
Proved Developed Reserves:						
September 30, 2000	8,224	57,771	79	66,074	35,130	101,204
September 30, 2001	6,259	44,304	77	50,640	33,676	84,316
September 30, 2002	5,111	41,735	94	46,940	24,100	71,040
September 30, 2003	**2,533**	**40,079**	**139**	**42,751**	**2,391**	**45,142**

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 widely fluctuating political and economic conditions.

The standardized measure is intended instead to provide a 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)	**2003**	2002	2001
United States			
Future Cash Inflows	**$2,684,286**	$2,764,556	$2,127,601
Less:			
Future Production Costs	**579,321**	546,182	602,479
Future Development Costs	**116,639**	117,999	121,240
Future Income Tax Expense at Applicable Statutory Rate	**613,893**	653,347	376,667
Future Net Cash Flows	**1,374,433**	1,447,028	1,027,215
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	**641,185**	665,941	421,865
Standardized Measure of Discounted Future Net Cash Flows	**733,248**	781,087	605,350
Canada			
Future Cash Inflows	**279,772**	888,515	890,381
Less:			
Future Production Costs	**85,817**	413,006	533,848
Future Development Costs	**9,787**	25,398	19,608
Future Income Tax Expense at Applicable Statutory Rate	**58,436**	101,919	76,191
Future Net Cash Flows	**125,732**	348,192	260,734
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	**40,575**	103,097	79,295
Standardized Measure of Discounted Future Net Cash Flows	**85,157**	245,095	181,439
Total			
Future Cash Inflows	**2,964,058**	3,653,071	3,017,982
Less:			
Future Production Costs	**665,138**	959,188	1,136,327
Future Development Costs	**126,426**	143,397	140,848
Future Income Tax Expense at Applicable Statutory Rate	**672,329**	755,266	452,858
Future Net Cash Flows	**1,500,165**	1,795,220	1,287,949
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	**681,760**	769,038	501,160
Standardized Measure of Discounted Future Net Cash Flows	**$818,405**	$1,026,182	$786,789

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

Year Ended September 30 (Thousands)	**2003**	2002	2001
United States			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	**$781,087**	$605,350	$1,240,375
Sales, Net of Production Costs	**(227,219)**	(163,548)	(301,634)
Net Changes in Prices, Net of Production Costs	**11,130**	441,085	(921,719)
Purchases of Minerals in Place	**—**	—	1,191
Sales of Minerals in Place	**—**	(27,197)	(17,552)
Extensions and Discoveries	**29,266**	42,970	52,062
Changes in Estimated Future Development Costs	**(35,062)**	(42,069)	(3,157)
Previously Estimated Development Costs Incurred	**36,423**	45,310	61,482
Net Change in Income Taxes at Applicable Statutory Rate	**24,796**	(126,263)	363,425
Revisions of Previous Quantity Estimates	**(3,572)**	(32,646)	(29,841)
Accretion of Discount and Other	**116,399**	38,095	160,718
Standardized Measure of Discounted Future Net Cash Flows at End of Year	**733,248**	781,087	605,350
Canada			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	**245,095**	181,439	277,757
Sales, Net of Production Costs	**(56,862)**	(41,023)	(51,638)
Net Changes in Prices, Net of Production Costs	**8,167**	111,148	(161,461)
Purchases of Minerals in Place	**—**	—	30,575
Sales of Minerals in Place	**(120,960)**	(3,084)	(761)
Extensions and Discoveries	**28,241**	29,813	39,752
Changes in Estimated Future Development Costs	**(14,045)**	18,151	(31,009)
Previously Estimated Development Costs Incurred	**29,657**	12,361	12,176
Net Change in Income Taxes at Applicable Statutory Rate	**(6,280)**	(6,910)	73,865
Revisions of Previous Quantity Estimates	**(41,205)**	(88,571)	(64,368)
Accretion of Discount and Other	**13,349**	31,771	56,551
Standardized Measure of Discounted Future Net Cash Flows at End of Year	**85,157**	245,095	181,439
Total			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	**1,026,182**	786,789	1,518,132
Sales, Net of Production Costs	**(284,081)**	(204,571)	(353,272)
Net Changes in Prices, Net of Production Costs	**19,297**	552,233	(1,083,180)
Purchases of Minerals in Place	**—**	—	31,766
Sales of Minerals in Place	**(120,960)**	(30,281)	(18,313)
Extensions and Discoveries	**57,507**	72,783	91,814
Changes in Estimated Future Development Costs	**(49,107)**	(23,918)	(34,166)
Previously Estimated Development Costs Incurred	**66,080**	57,671	73,658
Net Change in Income Taxes at Applicable Statutory Rate	**18,516**	(133,173)	437,290
Revisions of Previous Quantity Estimates	**(44,777)**	(121,217)	(94,209)
Accretion of Discount and Other	**129,748**	69,866	217,269
Standardized Measure of Discounted Future Net Cash Flows at End of Year	**$818,405**	$1,026,182	$786,789

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, 2003					
Reserve for Doubtful Accounts	**$17,299**	**$17,275**	**$ —**	**$16,631**	**$17,943**
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

(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

ITEM 9A 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-15(e) and 15d-15(e) 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 management, including the Chief Executive Officer and Treasurer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Treasurer concluded that the Company's disclosure controls and procedures were effective as of the end of the period covered by this report.

Changes in internal controls over financial reporting

The Company maintains a system of internal control over financial reporting that is 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 GAAP. There were no changes in the Company's internal control over financial reporting that occurred during the period covered by this report that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

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 19, 2004 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2003. 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 2006," "Directors Whose Terms Expire in 2005," "Directors Whose Terms Expire in 2004," 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.

The Company has adopted a Code of Business Conduct and Ethics that applies to the Company's directors, officers and employees and will post such Code of Business Conduct and Ethics on the Company's website, www.nationalfuelgas.com, together with certain other corporate governance documents, as soon as reasonable practicable after this report is filed with, or furnished to, the SEC. Copies of the Company's Code of Business Conduct and Ethics, charters of important committees and Corporate Governance Guidelines will be made available free of charge upon written request to Investors Relations, National Fuel Gas Company, 6363 Main Street, Williamsville, New York 14221.

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 19, 2004 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2003. 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	14,065,338	$22.41	807,351
Equity compensation plans not approved by security holders	0	0	0
Total	14,065,338	$22.41	807,351

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 19, 2004 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2003. 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 19, 2004 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2003. 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 19, 2004 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2003. 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.

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

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 19, 2004 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2003. The information concerning principal accountant fees and services is set forth in the definitive Proxy Statement under the caption "Independent Auditor's Fees" and is incorporated herein by reference.

Part IV

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 statement 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 12, 2002 (Exhibit 3(ii), Form 10-Q for quarterly period ended December 31, 2002 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)
- Officers Certificate establishing 5.25% Notes due 2013, dated February 18, 2003 (Exhibit 4, Form 10-Q for the quarterly period ended March 31, 2003 in File No. 1-3880)

(10) Material Contracts:

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

- Credit Agreement, dated as of September 30, 2002, among the Company, the Lenders and JPMorgan Chase Bank, (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2002 in File No. 1-3880)

(10.1) First Amendment to Credit Agreement, among the Company, the Lenders and JPMorgan Chase Bank, dated September 29, 2003

(iii) Compensatory plans for officers:

(10.2) Retirement Benefit Agreement, dated September 22, 2003, between the Company and David F. Smith

- 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)
- 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)
- Split Dollar Insurance Agreement, dated March 6, 2001, between the Company and James A. Beck (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2002 in File No. 1-3880)
- 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 2003

(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 Seneca Energy Canada, Inc.

23.3 Consent of Independent Accountants

(31) Rule 13(a)-15(e)/15d-15(e) Certifications

31.1 Written statements of Chief Executive Officer pursuant to Rule 13(a) - 15(e)/15(d) - 15(e) of the Exchange Act.

31.2 Written statements of Principal Financial Officer pursuant to Rule 13(a) - 15(e)/15(d) - 15(e) of the Exchange Act.

(32) Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

(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 Seneca Energy Canada, Inc.

99.3 Company Maps

- The Company agrees to furnish to the SEC upon request the following instruments with respect to long-term debt that the Company has filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(ii)(A):

  Secured Credit Agreement, dated as of June 5, 1997, among the Empire State Pipeline, as borrower, Empire State Pipeline, Inc., the Lenders party thereto, JPMorgan Chase Bank (f/k/a The Chase Manhattan Bank) as administrative agent, and Chase Securities, as arranger.

  First Amendment to Secured Credit Agreement dated as of May 28, 2002, among Empire State Pipeline, as borrower, Empire State Pipeline, Inc., St. Clair Pipeline Company, Inc., the Lenders party to the Secured Credit Agreement, and JPMorgan Chase Bank, as administrative agent.

  Second Amendment to Secured Credit Agreement, dated as of February 6, 2003, among Empire State Pipeline, as borrower, Empire State Pipeline, Inc., St. Clair Pipeline Company, Inc., the Lenders party to the Secured Credit Agreement, as amended, and JPMorgan Chase Bank, as administrative agent.

- *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 July 29, 2003 was furnished to the SEC on July 31, 2003, to report the sale of certain Canadian properties on July 29, 2003 and earnings for the quarter ended June 30, 2003 under Item 12, "Results of Operations and Financial Condition." 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 29, 2003

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 29, 2003

/s/ R. T. Brady
R. T. Brady
Director
Date: December 29, 2003

/s/ R. D. Cash
R. D. Cash
Director
Date: December 29, 2003

/s/ J. V. Glynn
J. V. Glynn
Director
Date: December 29, 2003

/s/ B. J. Kennedy
B. J. Kennedy
Director
Date: December 29, 2003

SIGNATURE / TITLE

/s/ R.E. Kidder
R.E. Kidder
Director
Date: December 29, 2003

/s/ B. S. Lee
B. S. Lee
Director
Date: December 29, 2003

/s/ G. L. Mazanec
G. L. Mazanec
Director
Date: December 29, 2003

/s/ J. F. Riordan
J. F. Riordan
Director
Date: December 29, 2003

/s/ J. P. Pawlowski
J. P. Pawlowski
Treasurer, Principal Financial Officer and Principal Accounting Officer
Date: December 29, 2003

Glossary

Absorption Chiller A device that uses a heat source such as combustion from a natural gas burner, steam or hot water rather than mechanical energy to produce chilled water. The chilled water, which is cooled through a heat exchanger, can then be circulated by pumps through pipes and cooling coils to be used for various space cooling, dehumidification or process cooling purposes.

Amortization The method of accounting whereby the cost of an asset is spread over its useful life.

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.

Cathodic Protection A means of protecting a buried pipe against corrosion. A current is directed into the pipe by sacrificial anodes (metal ribbons) placed in the ground parallel to and connected to the pipe. Pipe will not corrode if sufficient current flows onto the pipe.

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.

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.

Goodwill An intangible asset between the book value of a company and the price at which a company is purchased.

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

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

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

Hydraulic Fracture A mechanical method of increasing the permeability of rock, and thus increasing the amount of oil or gas produced from it. The method employs hydraulic pressure to fracture the rock. It is extensively employed on limestone formations.

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 energy.

Megawatt Hour A unit of energy which equals one megawatt of energy expended continuously 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.

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.

Trend Similar geologic features in a localized area.

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.

Veneer A thin surface layer of fine wood laid over a base of common material.

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.

INVESTOR INFORMATION

Common Stock Transfer Agent and Registrar*

Computershare Investor Services, LLC
2 North LaSalle Street
Mezzanine Level
Chicago, IL 60602
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
2 North LaSalle Street
Mezzanine Level
Chicago, IL 60602
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 19, 2004, at The Grand America Hotel, 555 South Main Street, Salt Lake City, UT 84111. Formal notice of the meeting, proxy statement and proxy will be mailed to shareholders of record as of the close of business on December 22, 2003.

Investor Relations

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Additional Shareholder Reports

Additional copies of this report and the Financial and Statistical Supplement to the 2003 Annual Report can be obtained without charge by writing to or calling:

Anna Marie Cellino, *Corporate Secretary*
Tel. (716) 857-7858

Margaret M. Suto, *Director, Investor Relations*
Tel. (716) 857-6987

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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 receive news releases automatically by e-mail. Simply go to the* **News** *section and subscribe.*

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