National Fuel Gas Company

2004 Annual Report

AND FORM 10-K

value

from the bottom of the well to the burner tip

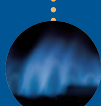
Corporate Profile

National Fuel Gas Company, incorporated in 1902, is a diversified energy company with its headquarters in Williamsville, New York. The Company's $3.7 billion in assets is distributed among six principal business segments: Exploration and Production, Pipeline and Storage, Utility, International, Energy Marketing, and Timber.

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 102-year tradition of delivering service and value.

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

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 3,013 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 approximately 732,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by this system include Buffalo, Niagara Falls and Jamestown in New York, and Erie and Sharon in Pennsylvania.

International *Horizon Energy Development, Inc.* engages in foreign and domestic energy projects through the investments of its subsidiaries as the sole or substantial owner of various business entities. Horizon's largest investment is a district steam heating and electric generating plant in the Czech Republic.

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.

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

Highlights

Year Ended September 30	2004	2003	2002	2001	2000
Operating Revenues *(Thousands)*	**$2,031,393**	$2,035,471	$1,464,496	$2,059,836	$1,412,416
Net Income Available for Common Stock *(Thousands)*	**$ 166,586**	$ 178,944 (1)	$ 117,682 (2)	$ 65,499 (3)	$ 127,207
Return on Average Common Equity (4)	**13.3%**	15.7%	11.2%	6.4%	13.0%
Per Common Share					
Basic Earnings	**$ 2.03**	$ 2.21 (5)	$ 1.47	$ 0.83	$ 1.63
Diluted Earnings	**$ 2.01**	$ 2.20 (5)	$ 1.46	$ 0.82	$ 1.61
Dividends Paid	**$ 1.09**	$ 1.05	$ 1.02	$ 0.97	$ 0.94
Dividend Rate at Year-End	**$ 1.12**	$ 1.08	$ 1.04	$ 1.01	$ 0.96
Book Value at Year-End	**$15.11**	$13.97	$12.54	$12.63	$12.55
Common Shares Outstanding at Year-End	**82,990,340**	81,438,290	80,264,734	79,406,105	78,659,606
Weighted Average Common Shares Outstanding					
Basic	**82,045,535**	80,808,794	79,821,430	79,053,444	78,233,842
Diluted	**82,900,438**	81,357,896	80,534,453	80,361,258	79,166,200
Average Common Shares Traded Daily	**223,600**	221,021	180,675	222,308	161,271
Common Stock Price					
High	**$28.43**	$27.51	$25.70	$32.25	$29.41
Low	**$21.71**	$17.95	$15.61	$21.96	$19.69
Close	**$28.33**	$22.85	$19.87	$23.03	$28.03
Net Cash Provided by Operating Activities *(Thousands)*	**$ 444,300**	$ 326,837	$ 345,550	$ 414,027	$ 238,246
Total Assets *(Thousands)*	**$3,711,798**	$3,719,060	$3,401,309	$3,445,231	$3,251,031
Expenditures for Long-Lived Assets *(Thousands)*	**$ 172,341**	$ 381,440	$ 232,904	$ 385,103	$ 398,777
Volume Information					
Utility Throughput-MMcf					
Gas Sales	**101,961**	112,162	101,444	104,186	97,617
Gas Transportation	**60,565**	64,232	61,909	66,283	71,862
Pipeline & Storage Throughput-MMcf					
Gas Transportation	**351,683**	350,929	297,822	321,555	313,548
Production Volumes					
Gas-MMcf	**33,013**	33,805	41,454	41,004	41,670
Oil-Mbbl	**4,528**	6,737	7,662	7,857	5,147
Total-MMcfe	**60,181**	74,227	87,426	88,146	72,552
Proved Reserves					
Gas-MMcf	**224,784**	251,117	258,221	322,380	301,667
Oil-Mbbl	**65,213**	69,764	99,717	115,328	119,697
Total-MMcfe	**616,062**	669,700	856,523	1,014,348	1,019,849
Energy Marketing Volumes-MMcf					
Gas	**41,651**	45,135	33,042	36,753	35,465
International Sales Volumes					
Heating (Gigajoules)	**8,538,554**	8,766,567	8,689,887	9,978,118	10,222,024
Electricity (Megawatt hours)	**936,877**	973,968	972,832	1,019,901	1,147,303
Average Number of Utility Retail Customers	**678,976**	680,007	680,489	678,357	656,792
Average Number of Utility Transportation Customers	**53,331**	53,381	51,729	54,140	78,610
Number of Employees at September 30 (6)	**2,918**	3,037	3,177	3,235	3,597

(1) Includes gain on sale of timber properties of $102.2 million, loss on sale of oil and gas assets of ($39.6) 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 producing properties of ($104.0) million.
(4) Calculated using average 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 863, 897, 944, 991 and 1,201 international employees at September 30, 2004, 2003, 2002, 2001 and 2000, respectively.

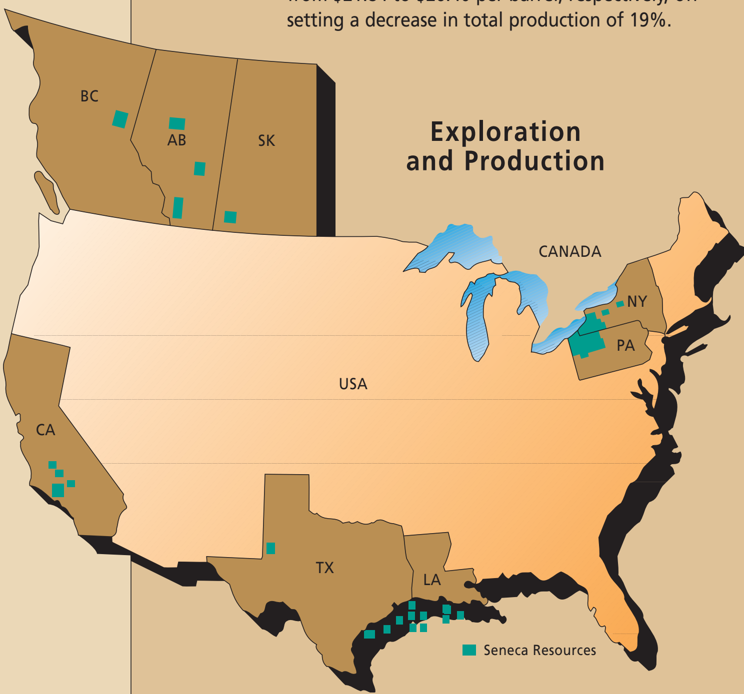
2004 At a Glance

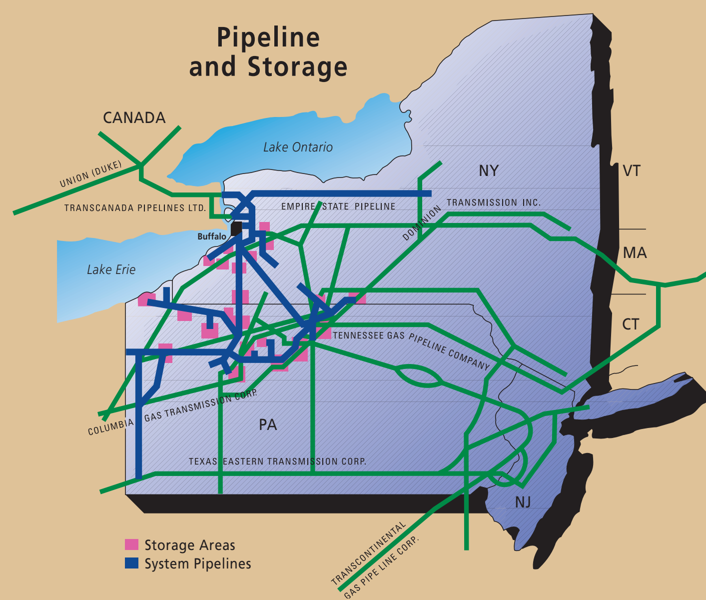
In 2004 **EXPLORATION AND PRODUCTION**

- Net Income of $54.3 million.
- Production of 60.2 Bcfe, 55% natural gas, 45% oil.
- Drilled 162 new wells with 96% success rate.
- Weighted average prices of natural gas and oil after hedging rose from $4.47 to $5.06 per Mcf and from $21.84 to $26.40 per barrel, respectively, offsetting a decrease in total production of 19%.

In 2004 **PIPELINE AND STORAGE**

- Net Income of $47.7 million contributed over 28% of total Company earnings.
- Commenced preliminary outreach and information gathering program for proposed Empire Connector project.





*Outlook** **EXPLORATION AND PRODUCTION**

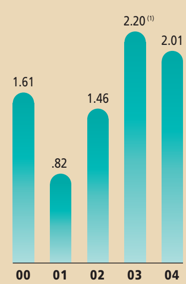
- Production goal of 50-55 Bcfe to emphasize natural gas drilling.
- Capital budget of $93 million planned to focus on areas of proven success, living within cash flow and controlling production costs.
- Plans to drill approximately 200 wells in 2005.

*Outlook** **PIPELINE AND STORAGE**

- Strategic value from Empire State Pipeline is emerging with proposed Empire Connector project.
- 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.

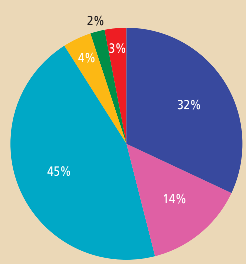
All references to years in this Annual Report are to the Company's fiscal year, which ends September 30.

Diluted Earnings Per Share
Dollars Per Share



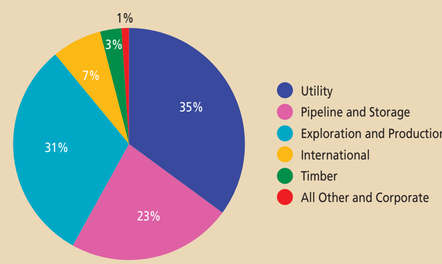
(1) Includes cumulative effect of changes in accounting of $(0.11) diluted.

Expenditures for Long-Lived Assets
by Segment



Total: $172.3 Million

Net Plant
by Segment



Total: $3.0 Billion

In 2004 **UTILITY**

- Net Income of $46.7 million, while providing nearly 28% of total Company earnings, is down $10.1 million from fiscal 2003.
- Filed rate cases in both New York and Pennsylvania divisions.
- New York rate case is the first filing since 1995.

ENERGY MARKETING

- Net Income was $5.5 million.

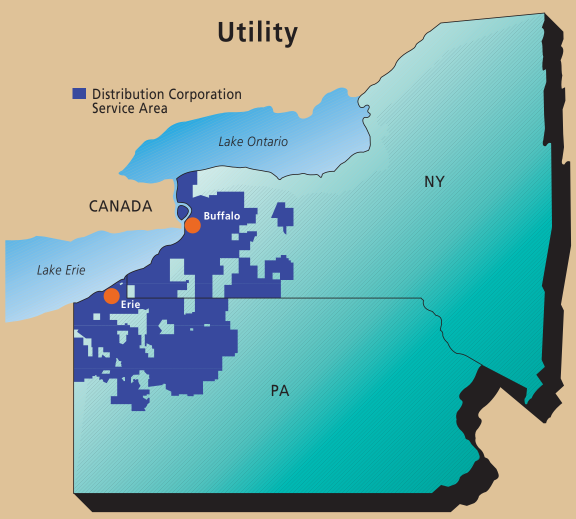
In 2004 **TIMBER**

- Net Income of $5.6 million.
- Production decreased only 7.5% to 31.4 million board feet from 34.0 million last year, following sale of approximately one-half of the timber properties.

*Outlook** **TIMBER**

- Earnings and production expected to remain at 2004 levels.

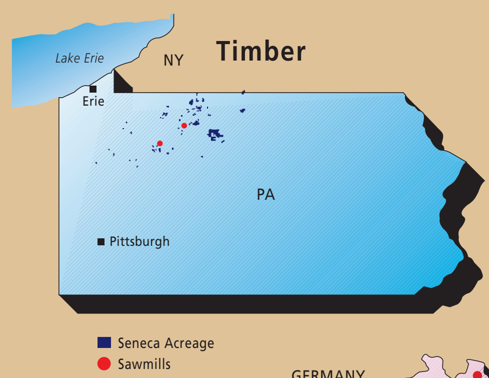
Utility



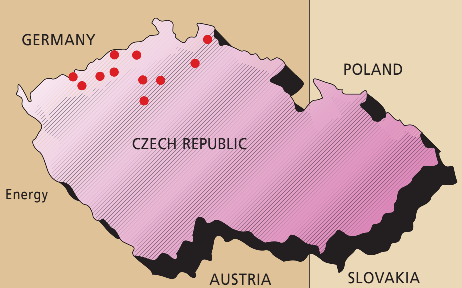
Energy Marketing

National Fuel Resources

Timber



International



*Outlook** **UTILITY**

- Anticipate conclusion of New York and Pennsylvania rate cases with new rates in effect in Summer 2005.
- Maintain excellent levels of operational safety and customer service while continuing to contain costs.

ENERGY MARKETING

- Continue focus on core markets, margin protection and providing energy expertise to commercial and individual customers.

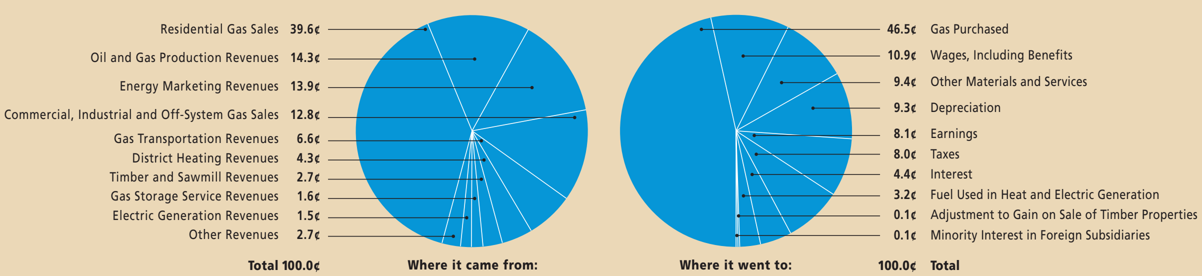
In 2004 **INTERNATIONAL**

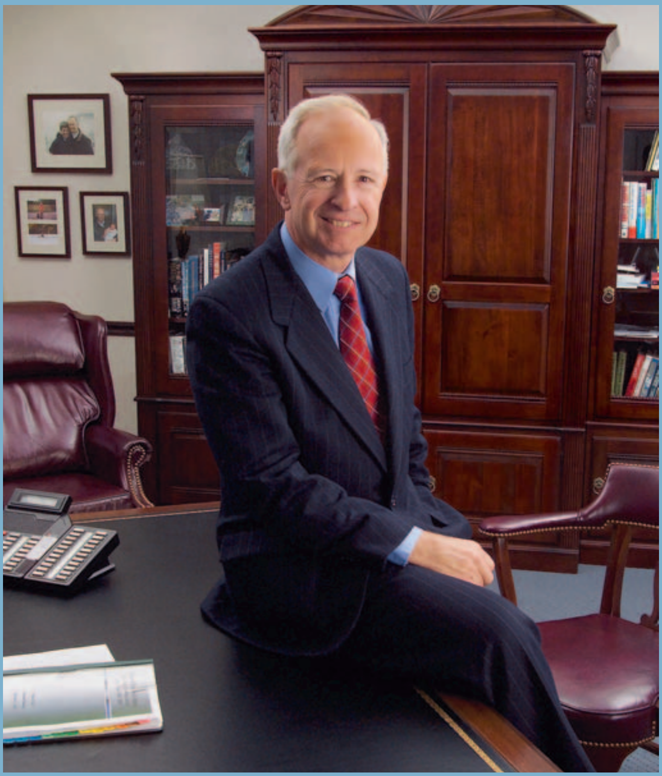
- Net Income of $6.0 million includes a $5.2 million one-time boost from a change in Czech Republic statutory income tax rate, reducing deferred income tax expense.

*Outlook** **INTERNATIONAL**

- Evaluating potential benefit of repatriating nearly $50 million of undistributed Czech earnings pursuant to the American Jobs Creation Act of 2004.

The Revenue Dollar – 2004

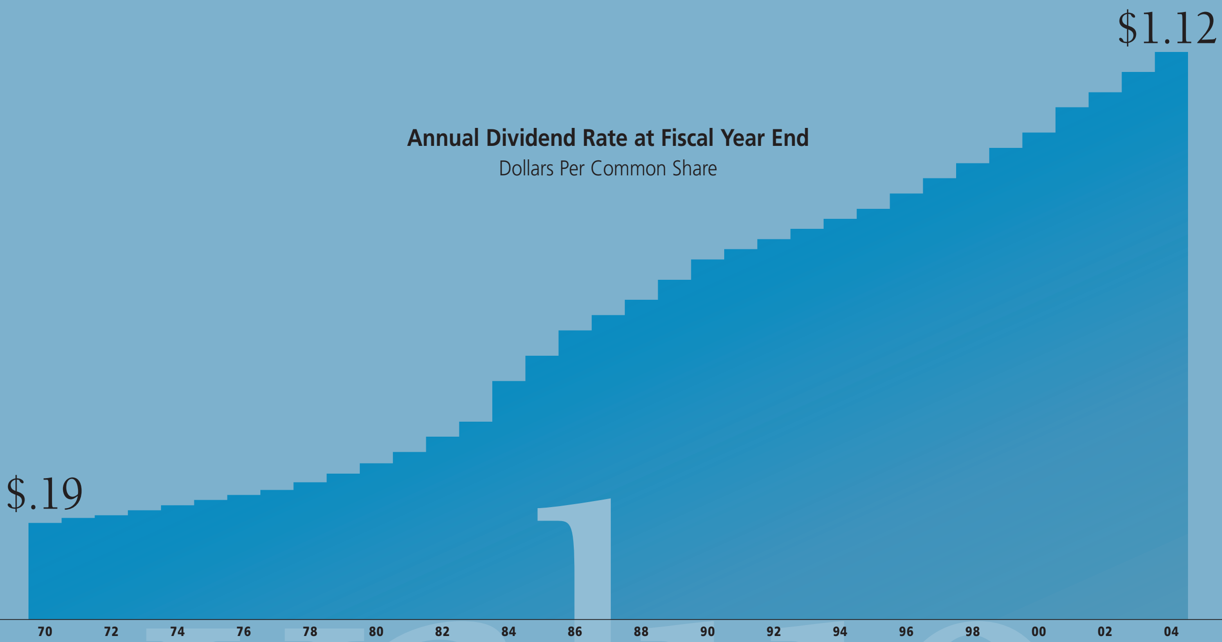




Philip C. Ackerman
Chairman of the Board, President
and Chief Executive Officer

To Our Shareholders

In 2004 the Board of Directors increased the dividend for the 34th consecutive year which marked our 102nd year of dividends.



value *for our shareholders*

In fiscal 2004, we continued to provide value to our shareholders in several ways. First, we reported earnings per share of $2.01, second only to last year's record of $2.20 which included the one-time gain from the sale of about one-half of our timberland. Second, on September 30 National Fuel's stock price closed at $28.33, our highest fiscal year end closing price.

Third, our annual dividend rate increased to $1.12 per share, up from $1.08 per share last year. That action marked the 34th consecutive year your Board of Directors has increased the dividend. Our fiscal 2004 payout ratio of 54% leaves room for future increases. Fourth, we paid down consolidated debt by more than $200 million, thus bringing the equity component of our total capitalization to just under 50% in contrast to 39% only two years ago. Fifth, our book value rose to a record $15.11 per share. The increased book value and increased equity component reflect a more conservative, more balanced financial structure that affords additional flexibility and reduces future interest expense.

For many years, we have spoken of our commitment to participate in the natural gas business from the bottom of the well to the burner tip, and this year's achievements reinforce that commitment.

Our Exploration and Production business, which faced its own challenges from time to time, particularly the non-cash write downs occasioned by falling prices and the arbitrary full-cost accounting rules, enjoyed robust earnings as a result of extraordinarily high oil and natural gas prices.

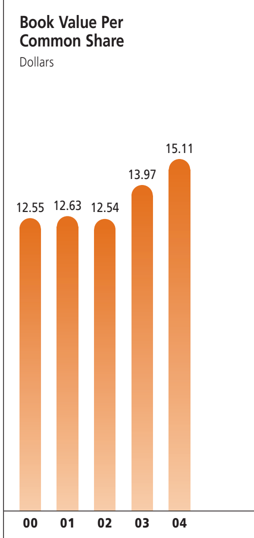
At the same time, the Pipeline and Storage segment, which has consistently provided favorable earnings but was challenged to grow, now appears to be on track to do so. It plans to build a $140 million pipeline extension from our existing Empire State Pipeline, connecting to the proposed Millennium Pipeline, which is scheduled to be built at the same time.* This, in turn, should set the stage for future expansions of this segment.*

Furthermore, while the Utility business had maintained its earnings performance for several years, this year we finally had to succumb to accumulating cost pressures and file rate cases in both the New York and Pennsylvania divisions.

Thus we see the value of this diversification through each of our segments: the past challenged performer having a robust year, the sterling but stagnant performer now seeing growth opportunities and the robust performer of recent years facing challenges. The discussion of each of our segments follows.

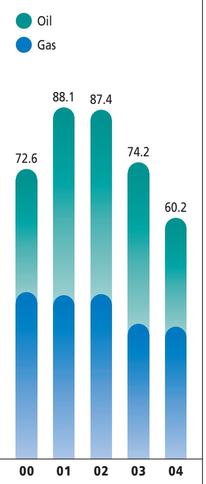
EXPLORATION AND PRODUCTION

This year, our Exploration and Production segment's earnings were $54.3 million, an increase of $86.2 million from last year's loss of $31.9 million. Both years' results included some items deserving particular mention: in 2003, earnings included non-cash impairments of oil and gas properties totaling nearly $29.0 million, the loss on the sale of the Canadian oil properties of $39.6 million and the adoption of an accounting rule change of $0.6 million; in 2004, there was a pension settlement loss of about $0.9 million and a positive adjustment of $4.6 million from the sale of the Canadian properties. I think a more enlightening comparison would be revealed by removing all these items; thus, this year's earnings would be $50.6 million compared to last year's $37.3 million.

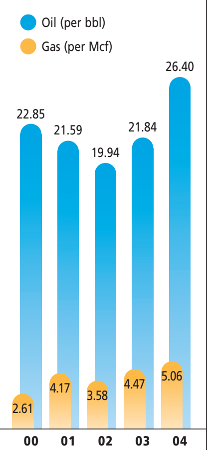


Note: This document contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements, including those designated by an asterisk ("*"), should be read with the cautionary statements and important factors included at Item 7 of the Company's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

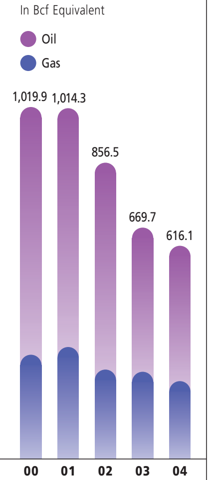
Oil and Gas Production
In Bcf Equivalent



Oil and Gas Prices
Weighted Average
After Hedging
Dollars



Proved Developed and
Undeveloped Reserves
In Bcf Equivalent



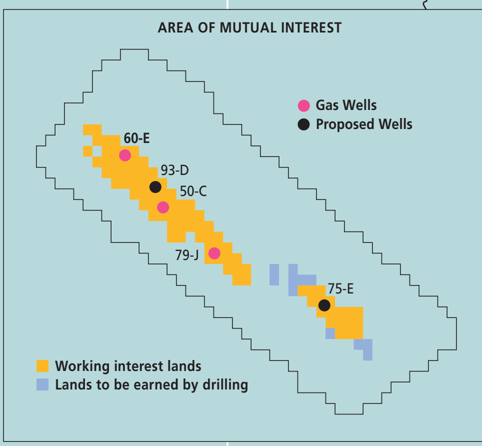
The 60.2 billion cubic feet equivalent (Bcfe) of production was well within our forecasted range of 57 to 62 Bcfe. Our oil and gas reserves at fiscal year end are 616 Bcfe; 64% of this is oil, 36% natural gas. While the balance is currently tipped away from natural gas, our exploration drilling plans for 2005 and 2006 concentrate primarily on natural gas prospects, allowing us to keep our annual production target at approximately 50% gas and 50% oil.*

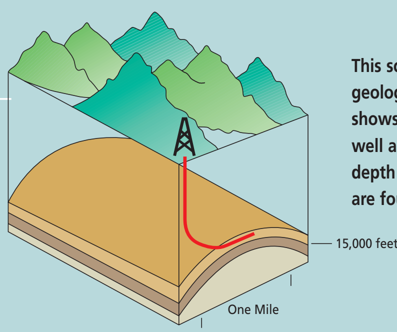
Our 2004 capital spending of $77.7 million enabled us to drill 162 wells with a 96% success rate, but many of these wells were either development wells or targeted modest reserves. One exception in 2004's drilling program was the Sukunka area in the northeastern region of the province of British Columbia, Canada. On November 1, 2004 Talisman Energy Inc., our joint venture operator, announced the successful completion of the Talisman Seneca Brazion b-60-E well in its core Monkman region. This well tested at rates up to 40 million cubic feet (MMcf) per day and should be on production in early calendar 2005.* We expect to participate in at least two more wells to be drilled in the Sukunka area during the next 12 months.* Our area of mutual interest in British Columbia, where these wells are located, encompasses over 200,000 acres. Through our Canadian subsidiary, we have a 20% working interest in this field.

Continued high prices for oil and natural gas make this segment an obvious candidate for expansion, but this is apparent to many others in our industry as well. Competition for prospects and acquisitions is intense and costs are high, but we will continue to pursue new opportunities.* Projected capital expenditures in 2005 of $93 million include plans for drilling approximately 200 new wells, with at least six exploratory wells in the Gulf of Mexico.* Our opportunities in the Gulf, although smaller than some of our historic successes, continue to be promising.* The West Cameron 77/96 block, operated by Newfield Exploration Company, tested at 14.1 MMcf per day, with 120 feet of net pay. Seneca has a 4.61% overriding interest until payout, then backs in to an 11.25% working interest. More wells in this block are planned.* In 2004, Seneca also announced it had acquired a 45% working interest before payout in six blocks in the Viosca Knoll region in the Gulf of Mexico with Chanex, LLC. As the operator of all wells drilled on these blocks, Seneca will retain a 33.75% working interest after payout. Drilling for this program should begin in the first quarter of calendar 2005.* Although these prospects are exciting and could be very profitable, we are focusing elsewhere for the long term.*

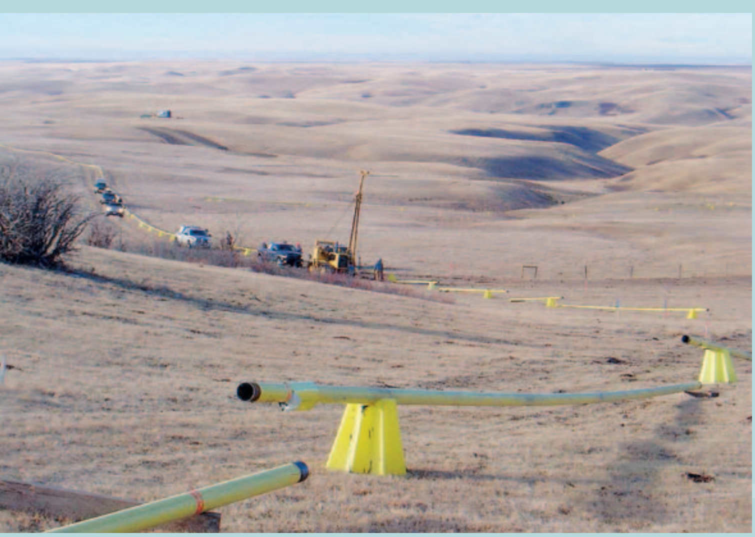
While our expansion capabilities are limited by a scarcity of reasonably priced opportunities, we can extract additional value by continuing to control our costs. For example, our California heavy oil production requires steaming of the oil before production and we currently purchase natural gas to produce this steam. During production, the oil wells generate a vapor which if released into the atmosphere, would not comply with California air quality emissions standards. This vapor is presently collected and reinjected into the well. However, with the high price of natural gas and the costs associated with the reinjection process, we are able to use existing technology to burn this well casing vapor, instead of natural gas, to make steam. This process, which will require an investment of $6 million, will enable us to continue to meet emission standards while significantly reducing the steaming costs per barrel of oil from about $2.34 to $0.96 per barrel.*

Seneca Resources' Canadian division owns a 20% working interest in the b-60-E well located in the Monkman region of northeastern British Columbia. Here, the well, the third completed this year, tested gas at rates up to 40 MMcf per day.





This schematic of a geological cross section shows the direction of the well and the approximate depth at which the reserves are found.

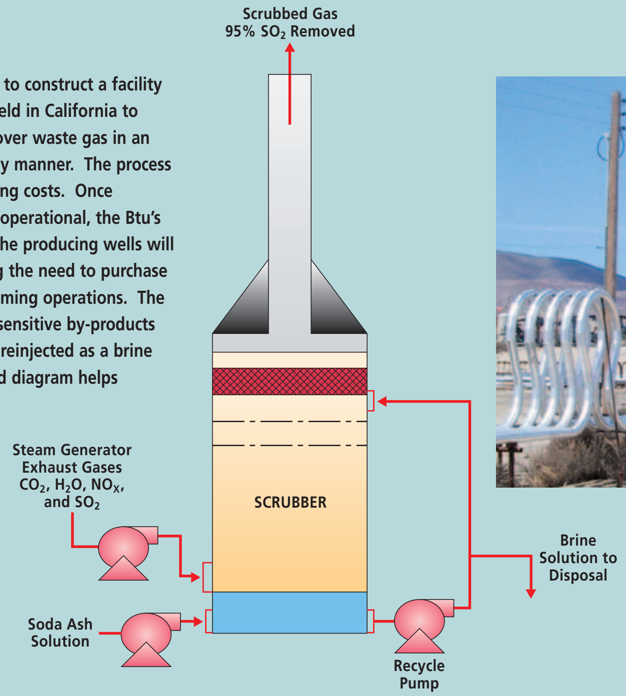


Construction crews install a four-inch plastic pipeline which will transport raw gas from two of Seneca's gas wells in the Watts field (located approximately 75 miles northeast of Calgary). The new pipeline will transport the gas to Seneca's compressor site at Watts.

value

in our resources

Seneca Resources plans to construct a facility at its Midway-Sunset field in California to produce steam and recover waste gas in an environmentally friendly manner. The process will also reduce operating costs. Once Seneca's new facility is operational, the Btu's in the waste gas from the producing wells will be recovered, offsetting the need to purchase natural gas for the steaming operations. The other environmentally sensitive by-products will be "scrubbed" and reinjected as a brine solution. This simplified diagram helps describe the process.



In July 2003, severe windstorms in northwestern Pennsylvania blew down acres of trees in areas where National Fuel's Timber segment operates. Demonstrating responsible land management and the ability to develop resources affected by natural occurrences, Highland has been working to salvage uprooted and crisscrossed trees near Mt. Jewett, Pennsylvania. As seen here, trees are transported from the area by a grapple skidder to a landing for loading onto trucks.

value

in our resources

PIPELINE AND STORAGE

Our Pipeline and Storage segment has consistently been our best performer. This year, earnings of $47.7 million were $2.5 million higher than last year. Earnings from the Empire State Pipeline were the principal contributor to this improvement.

The biggest news with regard to this segment is the proposed Empire Connector project. Many of you are aware that for years a number of competing pipeline expansion projects have been proposed to move large volumes of natural gas to the growing East Coast markets. The Dawn Hub, an area connecting storage and pipeline systems in southern Ontario and Michigan, offers access to gas from Canada, the mid-continent and the Gulf Coast. In the future, it is expected that Rocky Mountain and Alaska gas, and Gulf Coast liquefied natural gas (LNG) will also be available at the Dawn Hub.*

We have found a way to combine the best of the proposed pipeline projects to access the liquid market for natural gas at the Dawn Hub and bring those supplies of natural gas to the East Coast. Our proposed Empire Connector will allow us to utilize the western half of the existing Empire State Pipeline by connecting it with the eastern half of the proposed Millennium Pipeline.* The Empire Connector consists of about 80 miles of 24" pipeline and 21,000 horsepower of compression to be owned 100% by National Fuel. The proposed route begins near Victor, New York, just outside Rochester, and runs southerly to near Corning, New York. Construction costs for the mostly rural route are expected to be about $140 million.*

The key driver for this project is the participation of KeySpan Energy, a New York City-area gas and electric company, which has made it clear that it needs natural gas supply. In April of this year, KeySpan signed a Precedent Agreement committing to take 150 MMcf of the proposed 250 MMcf of daily capacity on the Empire Connector, subject to the satisfaction of certain terms and conditions in the Agreement.

In August we began a Federal Energy Regulatory Commission (FERC) recommended process for outreach and information gathering in anticipation of filing an application to build the Empire Connector. A series of public informational meetings were conducted in September in the towns along the pipeline's proposed route. Favorable weather in late summer and fall, and exceptional cooperation from landowners in the project area, facilitated access to properties along the proposed route by our environmental and survey crews. We are on track to submit our application to FERC in early calendar 2005, with a targeted in-service date of November 2006, provided the Millennium project is ready by then.* Given our strong balance sheet and cash flow, we should be able to pay for this project without going to the equity markets.*

This project is important both to our Company and to our industry. It will be a key route to deliver incremental gas supply to growing markets in the Northeast and it will increase the demand for storage services, which enable shippers to park gas during non-peak periods.* In addition, as LNG facilities, such as the Cove Point, Maryland LNG expansion project, are completed, there will be a greater need for gas storage services. Our storage facilities in the New York-Pennsylvania region provide access to the Leidy Hub and the proposed

Millennium Pipeline, and will become more valuable as this new source of gas supply develops late in this decade.* The fundamental strength of this segment continues to be our key location between major sources of gas supply and major markets.

UTILITY

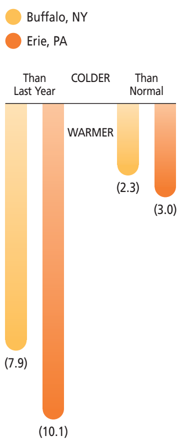
Earnings in our Utility segment were $46.7 million. This is $10.1 million less than last year's earnings of $56.8 million. Like other companies, we face increasing pressures from rising costs. For almost ten years, our Utility has been able to avoid base rate increases largely because we have focused intensely on cost containment and productivity gains. It is now clear that rising costs in areas such as healthcare, including medical, drug and hospitalization expenses over which we have limited control, are overwhelming our operational cost containment and productivity efforts in this segment. Thus, we have filed rate cases in both the New York and Pennsylvania divisions of our Utility. The New York filing requests an increase to revenues of $41.3 million on a requested return on equity of 11.88%. In Pennsylvania, the current filing requests a revenue increase of $22.8 million with a requested return on equity of 11.88%. Resolution of these rate cases is expected in mid-calendar 2005.*

Another continuing challenge for the Utility and the industry as a whole has been declining average residential volumes. Over the last 30 years, consumers have undertaken appropriate conservation measures, such as adding insulation and new storm doors, or replacing windows, furnaces and other gas appliances with more energy efficient ones. These efforts led to significant declines in average annual usage per residential account, especially during the 1970's and 1980's. While the rate of decline has slowed since then, during the last ten years the Utility's average annual residential volume per account has, nevertheless, declined approximately 12% to 114 thousand cubic feet (Mcf) of gas. We are working toward rate relief that will help manage the effects of this decline.*

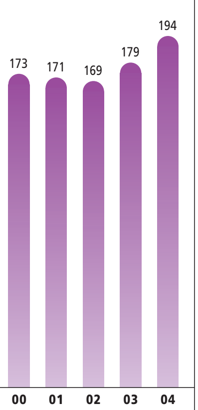
It is important to highlight the fact that, despite these cost and revenue pressures, our employees continue to provide exceptional service to our Utility customers. Surveys to measure performance in customer service show that our superior standards have not been compromised and our employees prove, time and time again, that they are committed to doing what is necessary to provide safe and reliable service to our customers. This core mission has been part of our fabric for more than 100 years and remains an utmost priority.

The run up in natural gas prices over the last few years has affected all consumers of natural gas and we have been very active in communicating with our Utility customers regarding the management of their energy bills and the reasons for increased prices. The employees of the Utility segment remain sensitive to the burden that high energy costs create for our customers and they continue to do an extraordinary job to help those in need navigate the landscape of available assistance programs. We were pleased to introduce, in our New York division, a new program developed with the State of New York Public Service Commission, which is designed to help low income customers who are transitioning from public assistance. This program provides an additional new safety net for a particularly vulnerable segment of our customer base. We look forward to its positive results.*

Fiscal 2004 Weather
Percent Colder (Warmer)



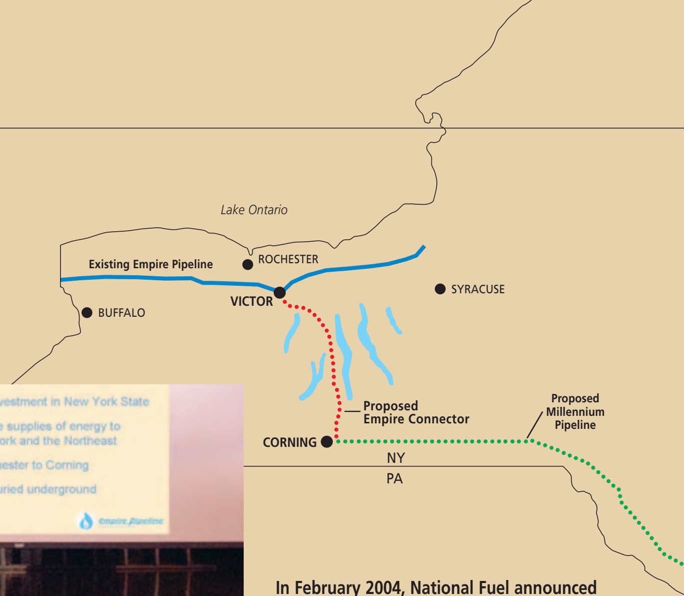
Utility Operation and Maintenance Expense
Millions of Dollars



National Fuel's Pipeline and Storage segment installed the measurement and regulation station pictured here at the Hebron storage field. This facility allows the Supply Corporation to immediately withdraw natural gas from the storage field and then place that gas directly into its interstate pipeline, increasing the marketability of its storage services and providing greater operational efficiencies.

Withdrawing natural gas from storage results in a reduction in its pressure, which cools the natural gas. Before going to market, gas must be reheated. The reheating process involves moving the gas through pipes located within a cylindrical vessel that contains heated glycol. Here, at the Hebron storage field, technicians fill the gas heater with glycol.

value *in our strategic location*



In February 2004, National Fuel announced plans to extend the Empire State Pipeline in order to serve new markets in the Northeast and New England. This past summer, the Company met with landowners and other interested parties to gather input during the planning phase of the project. Here, during one of seven public meetings, Empire State Pipeline Vice President Ron Kraemer addresses an audience in Victor, New York The session included an opportunity for guests to visit with members of the project team, ask questions and review preliminary maps of the proposed pipeline's route.

The Empire State Pipeline was inspected this year when the Company sent a smart pig, a device loaded with electronic measurement tools, through the pipeline. The pig traveled through the pipeline's entire 157-mile length and is received here at Empire's meter and regulating station near Mendon, New York. The instruments gather data about the pipe's thickness and also inspect it for signs of corrosion. The results of this inspection showed that the pipeline is in excellent condition. Here, employees Randy Goodman (left) and Joe Rostan discuss the testing process.

value *in our strategic location*

For our large commercial and industrial customers, we continue to promote and develop programs for natural gas-powered distributed generation (DG) on their premises. We are in the second year of our three-year DG pilot program in our New York division. The advantages of offering more efficient, secure, reliable and environmentally beneficial electric generation methods to these customers have been well received by the customers now participating in the program and we expect this program to grow.*

INTERNATIONAL

Earnings in the International segment were $6.0 million, an increase of $15.6 million from last year's loss of $9.6 million. A major boost to 2004 earnings came from legislation enacted in the Czech Republic where the statutory corporate income tax rate was reduced from 31% to 24% over a three-year period beginning January 1, 2004. This resulted in a $5.2 million reduction in deferred income tax expense in 2004. Offsetting this item somewhat was a pension settlement loss of $0.4 million. In fiscal 2003, we wrote off the goodwill associated with our Czech assets in the amount of $8.3 million. Absent these three items, earnings in this segment rose $2.6 million.

Limited progress has been made with respect to the power development projects we are pursuing in Italy and Bulgaria. Negotiations concerning the power purchase agreements and financing related to construction costs have not moved along as quickly as we would like, but we are unwilling to compromise our requirements regarding returns on and security of any capital we may invest.*

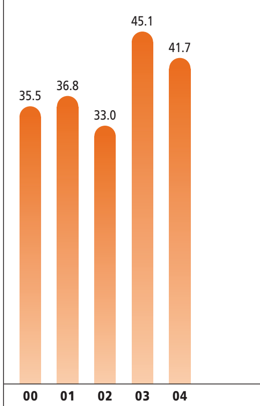
Another event that could prove to be of benefit to us is the recent passage of the American Jobs Creation Act of 2004. This domestic legislation provides a one-time, short-term reduced tax rate on certain repatriated foreign earnings. We currently have about $49.6 million of undistributed Czech earnings in addition to $35.8 million of unrecognized currency gain with respect to this investment. If we elect, in either fiscal 2005 or 2006, to bring back some or all of the earnings in the form of a dividend pursuant to an appropriate domestic reinvestment plan approved by the Board of Directors, the applicable corporate income tax rate would be 5.25% rather than the standard 35% rate. This is an excellent opportunity and a seemingly small price to repatriate nearly $50 million.*

ENERGY MARKETING

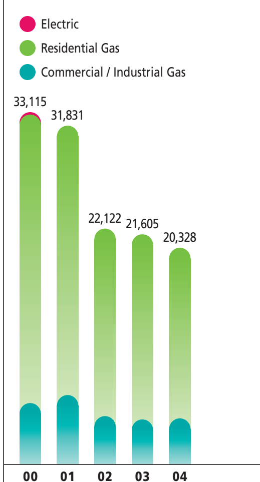
The Energy Marketing segment's earnings of $5.5 million were nearly unchanged from last year's earnings of $5.9 million, despite weather that was, on average 9%, warmer than a year ago. This relatively small segment is a key link in the chain from the well to the burner tip, since many end users of natural gas may choose to buy their gas from marketers rather than utilities. This segment produces these earnings with very little capital required.

In addition to selling natural gas to a variety of customers, including industrial, large and small commercial, public authority, and residential end users, this segment provides other energy management services such as retrofitting energy efficient lighting systems for commercial and industrial customers. These value-added services draw on our staff's expertise in the energy field and complement the segment's business offerings. Overall, this segment continues to benefit from a solid management team and it remains a logical and profitable part of our portfolio.

Natural Gas Marketing Volumes
Bcf



NFR Number of Customers



TIMBER

After last year's sale of nearly half of our timber properties, earnings in the Timber segment were $5.6 million, a decrease of $106.9 million compared to last year's earnings of nearly $112.5 million. Absent a gain of $102.2 million on the sale, last year's earnings were $10.2 million. In other words, after selling about one-half the property, earnings were about one-half of what they were before the sale.

Last year's tax-advantaged sale clearly demonstrated the value underlying these holdings. The earnings we achieve each year from this segment can be viewed as an annuity of sorts, coming from a resource that quietly replenishes itself. With our responsible stewardship, it will add value to your Company for years to come.*

Management and Director Changes

Several important management changes have taken place this past year. After 28 years of service, Joseph P. Pawlowski retired as Treasurer, Principal Financial Officer and Principal Accounting Officer of National Fuel Gas Company. Walter E. DeForest, Senior Vice President of National Fuel Gas Distribution Corporation, also retired after nearly 36 years of service. Ronald J. Tanski, the Controller of National Fuel Gas Company, was elected Treasurer and Principal Financial Officer, and in Ron's place, Karen M. Camiolo was elected Controller and Principal Accounting Officer. In addition, National Fuel Gas Distribution Corporation appointed Steven Wagner Vice President and David P. Bauer Assistant Treasurer.

Important changes are occurring at the Board level as well. Bernard S. Lee, Ph.D., a Board member since 1994 and Chairman of the Audit Committee, will be retiring at the upcoming Annual Meeting. We are grateful for his years of dedicated service and significant contributions to our Company, and wish him years of happiness. As a result of this pending vacancy, Richard G. Reiten was elected to the Board of Directors in December 2004 to stand for election at the Annual Meeting. Mr. Reiten, currently Chairman and formerly Chief Executive Officer of Northwest Natural Gas Company, brings extensive experience in all aspects of the natural gas industry. The Board also nominated Craig G. Matthews for election as a director at the Annual Meeting. Mr. Matthews, former Chief Executive Officer of NUI Corporation and former Vice Chairman and Chief Operating Officer of KeySpan Corporation, has nearly 40 years of energy industry experience.

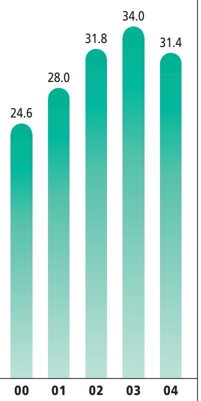
As shareholders, you have entrusted the Board of Directors, management and employees of National Fuel with the care and custody of nearly $4 billion in assets. These are real assets, with intrinsic value, capable of providing real, valuable services to our customers. Our people have a depth of experience and familiarity with these assets that enables us to unlock their maximum value without undue risk.

We remain committed to bringing value to you, our shareholders, through timely investments in the energy industry. We will not take for granted the trust you have put in us to do so. We remain committed to bringing value to our customers by safely, reliably and responsibly delivering natural gas. Lastly, we remain committed to being a diversified energy company so that we may continue to participate in the natural gas value chain, from the bottom of the well to the burner tip.

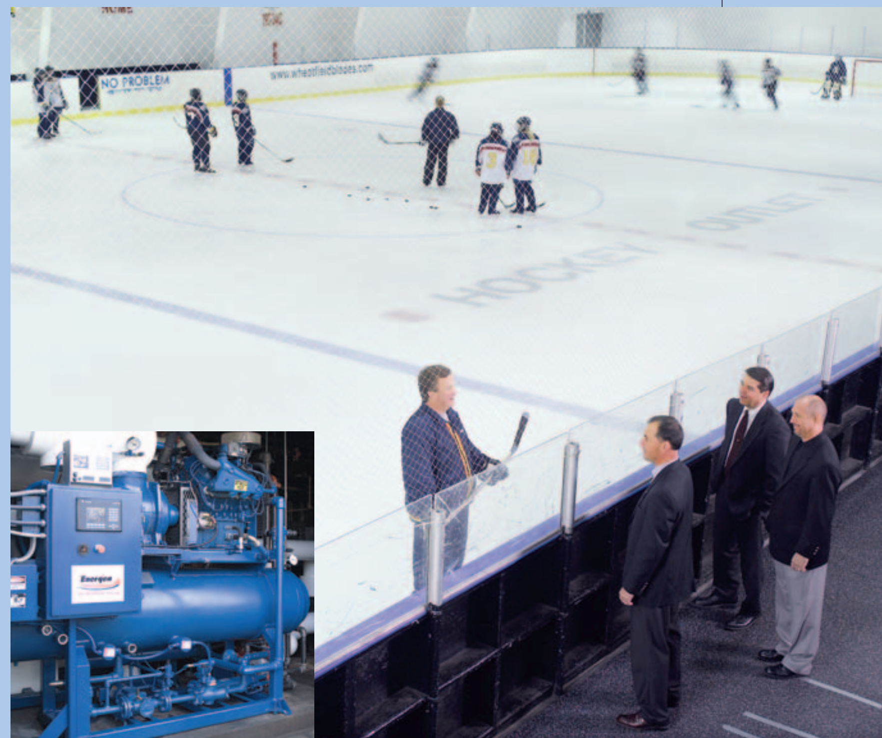
Philip C. Ackerman
Chairman of the Board, President and Chief Executive Officer

December 9, 2004

Timber Production
Board Feet in Millions



Hockey Outlet, an ice rink in Wheatfield, New York, installed a new natural gas-driven refrigeration unit this past summer. The unit uses natural gas to chill the ice surface, provide hot water and control humidity. National Fuel's Utility segment helped support the project with funding from its Research, Development and Demonstration program. Here, Hockey Outlet owner and coach Tim Igo (on ice skates) talks with National Fuel's David Burke (left) and Joseph Merckel and Howard Kielar of Energen, the manufacturer of the technology used here.



Representatives from Sweet Home Central School District in Amherst, New York meet with employees Jon Gallinger (right) and Howard Patton (left) to see the natural gas-fired microturbine installed for demonstration purposes at the Utility's service center in West Seneca, New York The school district is considering installing the technology to provide electricity and to supplement domestic hot water requirements in the winter months and absorption cooling in the summer.

With the establishment of the National Fuel Gas Company Foundation, the Company also created a new Employee Charitable Giving Program. At informational meetings held at locations throughout New York and Pennsylvania, employees learned how their personal charitable donations would go even farther with the addition of matching funds from the Foundation. Here, Brenda Spillman shares information with co-workers from the AppleTree Customer Response Center in Cheektowaga, New York.

value

in our service

Cummins Inc., a manufacturer of diesel engines in Jamestown, New York, worked with National Fuel Resources' Value Added Services group to design a new lighting system at its one million square foot manufacturing facility. The 2,600 new energy efficient lights will save Cummins more than $300,000 annually and qualified for a $274,000 rebate from the New York State Energy Research and Development Authority. National Fuel Resources' Gregg Morgan (center) and Cummins employees Bob Lanon, Jamie Grabel and Fred Gable examine the new lights, like those which glow brightly above them.

When Mercyhurst College, located in Erie, Pennsylvania, wanted to upgrade the heating system at the college's architectural center point, the solution required an innovative approach that would maintain the beauty of the building. Here, John Gordon of the Utility's Energy Services group (left) discusses the Gerster Trane-designed system with Mercyhurst's Tyrone Moore (standing, center) and Gerster Trane's Steve Aughey and Bill Flannigan. The natural gas-fired boilers will provide heat for the 40,000 square foot building this winter.

value

in our service

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, 2004

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 $1,997,020,000 as of March 31, 2004.

Common Stock, $1 Par Value, outstanding as of November 30, 2004: 83,178,717 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for the Annual Meeting of Shareholders to be held February 17, 2005 are incorporated by reference into Part III of this report.

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For the Fiscal Year Ended September 30, 2004

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

PART 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 732,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by Distribution Corporation include Buffalo, Niagara Falls and Jamestown, New York and Erie and Sharon, Pennsylvania.

2. The Pipeline and Storage segment operations are carried out by National Fuel Gas Supply Corporation (Supply Corporation), a Pennsylvania corporation, 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 from the United States/Canadian border at the Niagara River near Buffalo, New York to near Syracuse, New York. The Company acquired Empire in February 2003.

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, Louisiana, and Alabama. 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. At September 30, 2004, the Company had U.S. and Canadian reserves of 65,213 thousand barrels (Mbbl) and 224,784 million cubic feet (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. At September 30, 2004, the Company owned and managed approximately 87,000 acres of timber property.

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 direct wholly-owned subsidiaries are not included in any of the six reportable business segments and consist of the following:

- Horizon LFG, Inc. (Horizon LFG), a New York corporation engaged through subsidiaries in the purchase, sale and transportation of landfill gas in Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. Horizon LFG and one of its wholly owned subsidiaries own all of the partnership interests in Toro Partners, LP (Toro), a limited partnership which owns and operates short-distance landfill gas pipeline companies. Further information can be found in Item 8 at Note J — Acquisitions;
- 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 electric generation facilities.

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2004.

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 included repeal of the Holding Company Act, but since November 2003 have been unable to reconcile their differences and pass any comprehensive energy legislation. 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 State of New York Public Service Commission (NYPSC) with respect to services provided within New York and by the Pennsylvania Public Utility Commission (PaPUC) with respect to services provided within Pennsylvania. For additional discussion of the Utility segment's rates and regulation, see Item 7, MD&A under the heading "Rate Matters" and Item 8 at Note B-Regulatory Matters.

The Pipeline and Storage segment's rates, services and other matters with respect to Supply Corporation are regulated by the Federal Energy Regulatory Commission (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, to which other companies doing similar business in the same locations are subject.

The Utility Segment

The Utility segment contributed approximately 28.0% of the Company's 2004 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 28.6% of the Company's 2004 net income available for common stock.

Supply Corporation has service agreements for all of its firm storage capacity, which totals approximately 68,728 thousand dekatherms (MDth). The Utility segment has contracted for 27,865 MDth or 40.6% of the total storage capacity, and the Energy Marketing segment accounts for another 3,868 MDth or 5.6% of the total storage capacity. Nonaffiliated customers have contracted for the remaining 36,995 MDth or 53.8% of the firm storage capacity. Following an industry trend, most of Supply Corporation's storage and transportation services are performed under contracts that allow Supply Corporation or the shipper to terminate the contract upon six or twelve months' notice effective at the end of the contract term, and from time to time thereafter. At the beginning of 2005, approximately 88% of Supply Corporation's firm storage capacity (including the 40.6% contracted for by affiliated shippers) was committed under contracts that could have expired or been terminated before the end of 2005. Based on contract expirations and termination notifications received before the deadline for termination effective within 2005, contracts representing approximately 3.3% of Supply Corporation's firm storage capacity will be terminated during 2005.* 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.*

Supply Corporation's firm transportation capacity is not a fixed quantity, due to the diverse weblike nature of its pipeline system, and is subject to change as different transportation paths and receipt/delivery point combinations are identified with the market. Supply Corporation currently has firm transportation service agreements for approximately 2,232 MDth per day (contracted capacity). The Utility segment accounts for approximately 1,122 MDth per day or 50.3% of contracted capacity, and the Energy Marketing segment represents another 78 MDth per day or 3.5% of contracted capacity. The remaining 1,032 MDth or 46.2% of contracted capacity are subject to firm contracts with nonaffiliated customers.

At the beginning of 2005, 47% of Supply Corporation's contracted capacity was committed under affiliate contracts that could have expired or been terminated effective before the end of 2005. Based on contract expirations and termination notices received before the deadline for termination effective within 2005, affiliate contracts representing only 0.3% of contracted capacity will actually expire or be terminated effective during 2005. Similarly, 28% of contracted capacity was committed under unaffiliated shipper contracts that could expire or be terminated effective before the end of 2005. Based on contract expirations and termination notices received before the deadline for termination within 2005, unaffiliated contracts representing 11% of contracted capacity will actually expire or be terminated effective during 2005. Supply Corporation has been successful in marketing and obtaining executed contracts for such transportation service previously (at discounted rates when necessary), and expects to continue to do so.*

Empire has service agreements for the 2004-2005 winter period for all of its firm transportation capacity, which totals approximately 562 MDth per day. Approximately 74% of Empire's firm transportation capacity is contracted on a long-term basis. None of these transportation contracts could be terminated or will expire in 2005 or 2006. The Utility segment accounts for approximately 60 MDth per day or 10.7% of Empire's total capacity, and the Energy Marketing segment accounts for approximately 10 MDth per day or 1.8% of Empire's total capacity, with the remaining 87.5% of Empire's capacity subject to firm contracts with nonaffiliated customers. Approximately 14% of Empire's total capacity (including 5% of its total capacity contracted with affiliated shippers) is currently contracted under seasonal or annual contracts which will expire effective before the end of 2005.* Empire expects that all of this capacity will be re-contracted under seasonal and/or annual arrangements for future contracting periods.*

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

The Exploration and Production Segment

The Exploration and Production segment contributed approximately 32.6% of the Company's 2004 net income available for common stock.

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

The International Segment

The International segment contributed approximately 3.6% of the Company's 2004 net income available for common stock.

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 2004 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 3.4% of the Company's 2004 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 0.5% of the Company's 2004 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 2004, the Utility segment purchased 105 billion cubic feet (Bcf) of gas, of which 85 Bcf served core market demand and 17 Bcf was used for off-system sales. The remaining 3 Bcf represents gas used in operations offset by storage withdrawals. Gas purchased from producers and suppliers in the southwestern United States and Canada under firm contracts (seasonal and longer) accounted for 71% of the core market purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for the remaining 29% of the Utility segment's 2004 core market purchases. Purchases from Conoco Phillips Company (16%), Cinergy Marketing & Trading, L.P. (13%), BP Energy Company (11%), Occidental Energy Marketing, Inc. (10%) and Anadarko Energy Services Company (9%) accounted for 59% of the Utility's 2004 core market gas purchases. No other producer or supplier provided the Utility segment with more than 9% of its gas requirements in 2004.

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 in 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 54% of the cost of raw materials needed in 2004 to operate the boilers which produce steam or hot water. Natural gas, oil, limestone and water combined accounted for the remaining 46% of such materials. Coal is purchased and delivered directly from the adjacent Mostecka Uhelna Spolecnost, a.s. mine in the Czech Republic for UE'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 50% of the timber processed during 2004 came from land owned by Seneca.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2004, this segment purchased 44 Bcf of natural gas, of which 42 Bcf served core market demands. The remaining 2 Bcf largely represents gas used in operations.

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 have enhanced its competitive position relative to other fuels.

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 any further restructuring in response to 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, which was issued in 1992, 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, regulators in Pennsylvania have not pursued such programs recently, and there have been no significant new market entrants in New York. To date, the Utility segment's traditional distribution function remains largely unchanged; however, the NYPSC continues to encourage customer choice at the retail residential level.

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 competes, 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.*

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.

As announced in February 2004, Empire is pursuing a project to expand its natural gas pipeline to serve new markets in New York and elsewhere in the Northeast.* For further discussion of this 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 continues to progress, 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. Traditionally, the timber harvesting season occurs when timber growth is dormant and runs from approximately September to March. The operations conducted in the summer months typically focus on pulpwood and on thinning out lower-grade species from the timber stands to encourage the growth of higher-grade species. During 2004, several factors, including the sale of acreage in 2003, changes in market demands, and facility upgrades resulted in a change in our cutting schedule and a more level harvest each month.

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 2,918 full-time employees at September 30, 2004, with 2,055 employees in all of its U.S. operations and 863 employees in its international operations. This is a decrease of 3.9% from the 3,037 total employed at September 30, 2003.

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 on December 31, 2004. A new four-year contract is currently being negotiated.

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. The information available at the Company's internet website is not part of this Form 10-K or any other report filed with or furnished to the SEC.

Executive Officers of the Company as of November 15, 2004(1)

Name and Age (as of September 30, 2004)	Current Company Positions and Other Material Business Experience During Past Five Years
Philip C. Ackerman (60)	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.
David F. Smith (51)	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.
Dennis J. Seeley (61)	President of Supply Corporation since March 2000; President of Empire since February 2003; Senior Vice President of Distribution Corporation since February 1997. Mr. Seeley served as Vice President of the Company from January 2000 to April 2000.
James A. Beck (57)	President of Seneca since October 1996 and President of Highland since March 1998.
Ronald J. Tanski (52)	Treasurer of the Company since April 2004; Controller of the Company from February 2003 through March 2004; Senior Vice President of Distribution Corporation since July 2001; Controller of Distribution Corporation from February 1997 through March 2004; Treasurer of Distribution Corporation since April 2004; Treasurer and Secretary of Supply Corporation since April 2004; Secretary and Treasurer of Horizon since February 1997; and Vice President of Distribution Corporation from April 1993 to July 2001.
Karen M. Camiolo (45)	Controller of the Company since April 2004; Controller of Distribution Corporation and Supply Corporation since April 2004; Chief Auditor of the Company from July 1994 through March 2004.
Anna Marie Cellino (51)	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.
Bruce H. Hale (55)	President of Horizon Power since March 2001; Vice President of Horizon since September 1995. Mr. Hale previously served as Senior Vice President of Supply Corporation from February 1997 to March 2003.
John R. Pustulka (52)	Senior Vice President of Supply Corporation since July 2001; and Vice President of Supply Corporation from April 1993 to July 2001.
James D. Ramsdell (49)	Senior Vice President of Distribution Corporation since July 2001; and Vice President of Distribution Corporation from June 1994 to July 2001.

(1) The executive officers serve at the pleasure of the Board of Directors. The information provided relates to the Company and its principal subsidiaries. Many of the executive officers have served or currently serve as officers or directors of other subsidiaries of the Company.

Item 2 *Properties*

General Information on Facilities

The investment of the Company in net property, plant and equipment was $3.0 billion at September 30, 2004. Approximately 58% 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 (31%), is primarily located in California, in the Appalachian region of the United States, in Wyoming, in the Gulf Coast region of Texas, Louisiana, and Alabama 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 (7%) which is located in the Czech Republic, the Timber segment (3%) which is located primarily in northwestern Pennsylvania, and All Other and Corporate operations (1%). 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 $646 million, or 27%, since 1999.

The Utility segment had a net investment in property, plant and equipment of $1.0 billion at September 30, 2004. The net investment in its gas distribution network (including 14,781 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, 2004.

The Pipeline and Storage segment had a net investment of $696.5 million in property, plant and equipment at September 30, 2004. Transmission pipeline represents 37% of this segment's total net investment and includes 2,575 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 $91.1 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 $923.7 million at September 30, 2004. Of this amount, $780.9 million relates to properties located in the United States. The remaining net investment of $142.8 million relates to properties located in Canada.

The International segment had a net investment in property, plant and equipment of $227.9 million at September 30, 2004. 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 $82.8 million at September 30, 2004. 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 2004 peak day sendout, including transportation service, of 1,756.3 MMcf, which occurred on January 15, 2004. Withdrawals from storage of 736.2 MMcf provided approximately 41.9% 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, Louisiana, and Alabama. 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 2004, Seneca's proved developed and undeveloped reserves decreased modestly from the prior year. Natural gas reserves decreased from 251 Bcf at September 30, 2003 to 225 Bcf at September 30, 2004 and oil reserves decreased from 69,764 Mbbl to 65,213 Mbbl. These decreases are attributed primarily to the fact that U.S. and Canadian production outpaced net extensions and discoveries. Seneca's proved developed and undeveloped reserves also decreased in 2003 as compared to 2002. 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 the following 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 oil and gas reserves reported in Note N as of September 30, 2004 were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Ralph E. Davis Associates, Inc. Seneca reports its oil and gas reserve information on an annual basis to the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy. 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		
	2004	2003	2002
United States			
Gulf Coast Region			
Average Sales Price per Mcf of Gas	$ 5.61	$ 5.41	$ 2.89
Average Sales Price per Barrel of Oil	$35.31	$29.17	$22.83
Average Sales Price per Mcf of Gas (after hedging)	$ 4.78	$ 4.22	$ 3.69
Average Sales Price per Barrel of Oil (after hedging)	$31.51	$27.88	$22.51
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.60	$ 0.56	$ 0.60
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	73	75	100
West Coast Region			
Average Sales Price per Mcf of Gas	$ 5.54	$ 5.01	$ 2.86
Average Sales Price per Barrel of Oil	$31.89	$26.12	$19.94
Average Sales Price per Mcf of Gas (after hedging)	$ 5.72	$ 5.12	$ 2.86
Average Sales Price per Barrel of Oil (after hedging)	$22.86	$23.67	$20.09
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.05	$ 1.00	$ 0.81
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	55	59	63
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 5.91	$ 5.07	$ 3.74
Average Sales Price per Barrel of Oil	$31.30	$28.77	$23.76
Average Sales Price per Mcf of Gas (after hedging)	$ 5.72	$ 5.10	$ 3.74
Average Sales Price per Barrel of Oil (after hedging)	$31.30	$28.77	$23.76
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.54	$ 0.43	$ 0.53
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	14	14	12

	For the Year Ended September 30		
	2004	2003	2002
Total United States			
Average Sales Price per Mcf of Gas	$ 5.66	$ 5.28	$ 2.99
Average Sales Price per Barrel of Oil	$33.13	$27.16	$21.03
Average Sales Price per Mcf of Gas (after hedging)	$ 5.11	$ 4.52	$ 3.58
Average Sales Price per Barrel of Oil (after hedging)	$26.06	$25.11	$21.01
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.76	$ 0.72	$ 0.67
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	142	148	175
Canada			
Average Sales Price per Mcf of Gas	$ 4.87	$ 4.67	$ 2.29
Average Sales Price per Barrel of Oil	$30.94	$26.41	$19.94
Average Sales Price per Mcf of Gas (after hedging)	$ 4.87	$ 4.20	$ 3.59
Average Sales Price per Barrel of Oil (after hedging)	$30.94	$15.85	$18.11
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.00	$ 1.65	$ 1.29
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	22	55	64
Total Company			
Average Sales Price per Mcf of Gas	$ 5.51	$ 5.18	$ 2.88
Average Sales Price per Barrel of Oil	$32.98	$26.90	$20.63
Average Sales Price per Mcf of Gas (after hedging)	$ 5.06	$ 4.47	$ 3.58
Average Sales Price per Barrel of Oil (after hedging)	$26.40	$21.84	$19.94
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.80	$ 0.97	$ 0.84
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	164	203	239

Productive Wells

	United States							
	Gulf Coast Region		West Coast Region		Appalachian Region		Total U.S.	
At September 30, 2004	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	32	34	—	1,155	1,912	31	1,944	1,220
Productive Wells — Net	20	15	—	1,146	1,837	25	1,857	1,186

Productive Wells

	Canada		Total Company	
At September 30, 2004	Gas	Oil	Gas	Oil
Productive Wells — Gross	177	49	2,121	1,269
Productive Wells — Net	124	34	1,981	1,220

Developed and Undeveloped Acreage

At September 30, 2004	United States: Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada	Total Company
Developed Acreage — Gross	102,270	9,839	508,466	620,575	109,194	729,769
— Net	76,549	9,469	481,732	567,750	74,302	642,052
Undeveloped Acreage — Gross	206,619	—	464,525	671,144	421,690	1,092,834
— Net	115,909	—	440,004	555,913	316,820	872,733

As of September 30, 2004, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 142,172 acres in 2005 (106,758 net acres), 98,660 acres in 2006 (91,148 net acres), 130,707 acres in 2007 (80,783 net acres), and 721,295 acres thereafter (594,044 net acres).

Drilling Activity

For the Year Ended September 30	Productive 2004	Productive 2003	Productive 2002	Dry 2004	Dry 2003	Dry 2002
United States						
Gulf Coast Region						
Net Wells Completed — Exploratory	—	1.25	1.27	0.50	—	3.67
— Development	0.65	2.10	0.31	—	—	—
West Coast Region						
Net Wells Completed — Exploratory	—	—	—	—	—	—
— Development	49.00	30.97	47.99	—	—	2.00
Appalachian Region						
Net Wells Completed — Exploratory	—	3.00	3.00	3.00	0.10	1.00
— Development	41.00	58.00	27.00	—	—	0.10
Total United States						
Net Wells Completed — Exploratory	—	4.25	4.27	3.50	0.10	4.67
— Development	90.65	91.07	75.30	—	—	2.10
Canada						
Net Wells Completed — Exploratory	52.85	5.00	0.20	6.08	2.50	4.00
— Development	10.50	17.16	33.70	—	5.00	7.90
Total						
Net Wells Completed — Exploratory	52.85	9.25	4.47	9.58	2.60	8.67
— Development	101.15	108.23	109.00	—	5.00	10.00

Present Activities

At September 30, 2004	United States: Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada	Total Company
Wells in Process of Drilling(1) — Gross	1.00	5.00	25.00	31.00	1.00	32.00
— Net	0.67	5.00	24.05	29.72	1.00	30.72

(1) Includes wells awaiting completion.

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.

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. The 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. The Court changed venue of the action to New York State Supreme Court, Erie County. The litigation is in the early stages of discovery. For a discussion of a related matter before the NYPSC, refer to Item 7 — MD&A of this report under the heading "Regulatory Matters."

On December 22, 2003, the Pennsylvania Department of Environmental Protection (DEP) issued an order to Seneca to halt its timber harvesting operations on 21,000 acres in Cameron, Elk and McKean counties in Pennsylvania. The order asserts certain violations of DEP regulations concerning erosion, sedimentation and stream crossings. The order requires Seneca to apply for certain permits, control erosion, submit plans for removal of water encroachments not included in permit applications, notify the DEP of additional current or planned timber harvesting operations, and grant the DEP access to timber acreage. On January 9, 2004, Seneca filed with the Pennsylvania Environmental Hearing Board (Hearing Board) a notice of appeal, objecting to each finding and order contained in the order, and asserting that the DEP's findings are factually incorrect, an arbitrary exercise of the DEP's functions and duties, and contrary to law. Also on January 9, 2004, Seneca filed with the Hearing Board a petition requesting a stay of operation of portions of the order. On January 16, 2004, the parties settled Seneca's request for a stay. Seneca has resumed its timber harvesting operations pursuant to the terms of the settlement. The settlement preserves various issues raised by the DEP's order for a hearing on the merits of Seneca's notice of appeal. The most substantial question involves whether Seneca is required to apply for a permit under Section 102.5(b) of Title 25 of the Pennsylvania Code, governing earth disturbance activities of greater than 25 acres. The DEP takes the position that Seneca must aggregate the acreage of all of its logging sites across its entire 21,000 acre tract for purposes of determining whether its earth disturbing activities meet the 25 acres threshold. Seneca maintains that no permit is required, because the law does not require aggregation and each of its individual logging sites disturbs less than 25 acres. Seneca is engaged in negotiations to resolve this dispute on acceptable terms, and litigation deadlines have been extended to accommodate those discussions.

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 quarter ended September 30, 2004.

PART II

Item 5 *Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

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, 2004, the Company issued a total of 1,800 unregistered shares of Company common stock to the six non-employee directors of the Company then serving on the Board of Directors, 300 shares to each such director. All of these unregistered shares were issued as partial consideration for such directors' services during the quarter ended September 30, 2004, 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.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs
July 1-31, 2004	59,546	$26.04	—	—
Aug. 1-31, 2004	35,616	$26.49	—	—
Sept. 1-30, 2004	216,163	$27.97	—	—
Total	311,325	$27.43	—	—

(a) Represents (i) shares of common stock of the Company purchased on the open market with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock options or shares of restricted stock for the payment of option exercise prices and/or applicable withholding taxes.

Item 6 ***Selected Financial Data(1)***

	Year Ended September 30				
	2004	2003	2002 (Thousands)	2001	2000
Summary of Operations					
Operating Revenues	$2,031,393	$2,035,471	$1,464,496	$2,059,836	$1,412,416
Operating Expenses:					
Purchased Gas	949,452	963,567	462,857	1,002,466	488,383
Fuel Used in Heat and Electric Generation	65,722	61,029	50,635	54,968	54,893
Operation and Maintenance	413,593	386,270	394,157	364,318	350,383
Property, Franchise and Other Taxes	72,111	82,504	72,155	83,730	78,878
Depreciation, Depletion and Amortization	189,538	195,226	180,668	174,914	142,170
Impairment of Oil and Gas Producing Properties	—	42,774	—	180,781	—
	1,690,416	1,731,370	1,160,472	1,861,177	1,114,707
Gain (Loss) on Sale of Timber Properties	(1,252)	168,787	—	—	—
Gain (Loss) on Sale of Oil and Gas Producing Properties	4,645	(58,472)	—	—	—
Operating Income	344,370	414,416	304,024	198,659	297,709
Other Income (Expense):					
Income from Unconsolidated Subsidiaries	805	535	224	1,794	1,669
Impairment of Investment in Partnership	—	—	(15,167)	—	—
Other Income	6,671	6,887	7,017	10,639	6,366
Interest Expense on Long-Term Debt	(83,827)	(92,766)	(90,543)	(81,851)	(67,195)
Other Interest Expense	(6,763)	(12,290)	(15,109)	(25,294)	(32,890)
Income Before Income Taxes and Minority Interest in Foreign Subsidiaries	261,256	316,782	190,446	103,947	205,659
Income Tax Expense	92,737	128,161	72,034	37,106	77,068
Minority Interest in Foreign Subsidiaries	(1,933)	(785)	(730)	(1,342)	(1,384)
Income Before Cumulative Effect of Changes in Accounting	166,586	187,836	117,682	65,499	127,207
Cumulative Effect of Changes in Accounting	—	(8,892)	—	—	—
Net Income Available for Common Stock	$ 166,586	$ 178,944	$ 117,682	$ 65,499	$ 127,207

	Year Ended September 30				
	2004	2003	2002	2001	2000
			(Thousands)		
Per Common Share Data					
Basic Earnings per Common Share	$ 2.03	$ 2.21[(2)]	$ 1.47	$ 0.83	$ 1.63
Diluted Earnings per Common Share	$ 2.01	$ 2.20[(2)]	$ 1.46	$ 0.82	$ 1.61
Dividends Declared	$ 1.10	$ 1.06	$ 1.03	$ 0.99	$ 0.95
Dividends Paid	$ 1.09	$ 1.05	$ 1.02	$ 0.97	$ 0.94
Dividend Rate at Year-End	$ 1.12	$ 1.08	$ 1.04	$ 1.01	$ 0.96
At September 30:					
Number of Common Shareholders	19,063	19,217	20,004	20,345	21,164
Net Property, Plant and Equipment *(Thousands)*					
Utility	$1,048,428	$1,028,393	$ 960,015	$ 945,693	$ 939,753
Pipeline and Storage	696,487	705,927	487,793	483,222	474,972
Exploration and Production	923,730	925,833	1,072,200	1,081,622	998,852
International	227,905	219,199	207,191	178,250	172,602
Energy Marketing	80	171	125	262	360
Timber	82,838	87,600	110,624	90,453	95,607
All Other	21,172	22,042	6,797	1,209	1,241
Corporate	6,124	1,883	—	2	4
Total Net Plant	$3,006,764	$2,991,048	$2,844,745	$2,780,713	$2,683,391
Total Assets *(Thousands)*	$3,711,798	$3,719,060	$3,401,309	$3,445,231	$3,251,031
Capitalization *(Thousands)*					
Comprehensive Shareholders' Equity	$1,253,701	$1,137,390	$1,006,858	$1,002,655	$ 987,437
Long-Term Debt, Net of Current Portion	1,133,317	1,147,779	1,145,341	1,046,694	953,622
Total Capitalization	$2,387,018	$2,285,169	$2,152,199	$2,049,349	$1,941,059

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

(2) 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 Operations*

OVERVIEW

The Company is a diversified energy company consisting of six reportable business segments. Refer to Item I, Business, for a more detailed description of each of the segments. This Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), provides information concerning:

1. The critical accounting policies of the Company;
2. Changes in revenues and earnings of the Company under the heading, "Results of Operations;"
3. Operating, investing and financing cash flows under the heading "Capital Resources and Liquidity;"
4. Off-Balance Sheet Arrangements;

5. Contractual Obligations; and

6. Other Matters, including: a.) disclosures and tables concerning market risk sensitive instruments, b.) rate matters in the Company's New York, Pennsylvania and FERC regulated jurisdictions, c.) environmental matters, and d.) new accounting pronouncements.

The information in MD&A should be read in conjunction with the Company's financial statements in Item 8 of this report.

Throughout MD&A, a few events will stand out that impact the results of operations and capital resources and liquidity of the Company for 2004 and 2003. First, the Company, in its Exploration and Production segment, sold its Southeast Saskatchewan oil and gas properties in 2003 after a thorough review of the economics of its non-regulated business. These properties were sold given their overall marginal contribution to earnings. Second, the Company's Exploration and Production segment benefited from higher commodity prices in 2004. Third, the Company, in its Pipeline and Storage segment, purchased Empire State Pipeline (Empire) from Duke Energy Corporation on February 6, 2003. Empire was acquired because the Company believes that the pipeline 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.* In furtherance of that objective, in February 2004, the Company announced that it is pursuing an extension of the Empire State Pipeline as an upstream supply link for Phase I of the Millennium Pipeline. Fourth, the Company, in its Timber segment, sold approximately 70,000 acres of timber properties in August 2003 as a means of financing its acquisition of Empire. The Company recognized the concerns about its debt to capital ratio after the Empire acquisition and therefore sold these timber properties to reduce the short-term debt used to initially finance the acquisition.

Another event, which occurred in 2003 and is discussed more fully in Item 8 at Note J – Acquisitions, is the acquisition of all of the partnership interests in Toro Partners, L.P. (Toro). The Company has been successful in operating landfill gas projects, where the gas is used to generate electricity, and this acquisition allows the Company to operate short-distance landfill gas pipelines that purchase, transport and resell landfill gas to customers.

Overall, the Company emphasized debt reduction in 2004 and, to that end, has reduced its debt to capitalization ratio from .57 at September 30, 2003 to .51 at September 30, 2004.

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 the depletion calculation until they are evaluated. Once they are evaluated, costs associated with these properties 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 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 which 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 the March 31, 2003 ceiling test calculation. At September 30, 2003, the capitalized costs of Canadian oil and gas properties less accumulated depletion and related deferred taxes were nearly equal to the ceiling for Canadian oil and gas properties. During 2004, the Canadian oil and gas properties passed the quarterly ceiling tests but capitalized costs less accumulated depletion and related deferred taxes were still nearly equal to the ceiling at September 30, 2004. A downward revision to reserves or prices could result in an impairment of the Canadian oil and gas properties in the future.

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 limit 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."

RESULTS OF OPERATIONS

EARNINGS

2004 Compared with 2003

The Company's earnings were $166.6 million in 2004 compared with earnings of $178.9 million in 2003. The decrease in earnings is primarily the result of lower earnings in the Timber and Utility segments partially offset by higher earnings in the Exploration and Production, International, and Pipeline and Storage segments, as shown in the table below. Earnings were impacted by several events in 2004 and 2003, including:

2004 Events

- A $5.2 million reduction to deferred income tax expense in the International segment resulting from a change in the statutory income tax rate in the Czech Republic;

- Settlement of a pension obligation which resulted in the recording of additional expense amounting to $6.4 million after tax, allocated among the segments as follows: $2.2 million to the Utility segment ($1.2 million in the New York jurisdiction and $1.0 million in the Pennsylvania jurisdiction), $2.0 million to the Pipeline and Storage segment ($1.8 million to Supply Corporation and $0.2 million to Empire State Pipeline), $0.9 million to the Exploration and Production segment, $0.4 million to the International segment, $0.3 million to the Energy Marketing segment and $0.6 million to the Corporate and All Other categories;

- An adjustment to the 2003 sale of the Company's Southeast Saskatchewan oil and gas properties in the Exploration and Production segment which increased 2004 earnings by $4.6 million; and

- An adjustment to the Company's 2003 sale of its timber properties in the Timber segment, which reduced 2004 earnings by $0.8 million after tax.

2003 Events

- 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;

- The Company's Exploration and Production segment completed the sale of its Southeast Saskatchewan oil and gas properties in Canada, recording an after tax loss of $39.6 million;

- The Company's Exploration and Production segment recorded after tax impairment charges of $28.9 million related to its Canadian oil and gas assets;

- 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; and

- 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.

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. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows.

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 was 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 was impacted by the 2003 events listed above. Also, 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). 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		
	2004	2003	2002
		(Thousands)	
Utility	$ 46,718	$ 56,808	$ 49,505
Pipeline and Storage	47,726	45,230	29,715
Exploration and Production	54,344	(31,930)	26,851
International	5,982	(9,623)	(4,443)
Energy Marketing	5,535	5,868	8,642
Timber	5,637	112,450	9,689
Total Reportable Segments	165,942	178,803	119,959
All Other	1,530	193	(885)
Corporate	(886)	(52)	(1,392)
Total Consolidated	$166,586	$178,944	$117,682

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2004	2003	2002
		(Thousands)	
Retail Revenues:			
Residential	$ 808,740	$ 801,984	$538,345
Commercial	137,092	137,905	86,963
Industrial	17,454	23,263	18,332
	963,286	963,152	643,640
Off-System Sales	106,841	107,220	68,606
Transportation	80,563	86,374	83,267
Other	1,951	6,237	(1,292)
	$1,152,641	$1,162,983	$794,221

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30		
	2004	2003	2002
Retail Sales:			
Residential	70,109	76,449	64,639
Commercial	12,752	14,177	11,549
Industrial	2,261	3,537	3,715
	85,122	94,163	79,903
Off-System Sales	16,839	17,999	21,541
Transportation	60,565	64,232	61,909
	162,526	176,394	163,353

Degree Days

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Prior Year
2004:	Buffalo	6,729	6,572	(2.3)%	(7.9)%
	Erie	6,277	6,086	(3.0)%	(10.1)%
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)%

2004 Compared with 2003

Operating revenues for the Utility segment decreased $10.3 million in 2004 compared with 2003. This resulted largely from a decrease in transportation revenues of $5.8 million and a decrease in other revenues of $4.3 million. Transportation revenues decreased because of lower volumes being transported as a result of fuel switching, a general economic downturn in the Utility segment's service territory and warmer weather, as shown in the degree day table above. Retail revenues did not change significantly from the prior year as the impact to revenues of lower retail sales volumes was largely offset by the recovery of higher gas costs (gas costs are recovered dollar for dollar in revenues) and a base rate increase in the Utility segment's Pennsylvania jurisdiction. 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." Warmer weather and lower customer usage per account were the major factors in the decrease in retail sales volumes. The decrease in retail industrial sales volumes can be attributed to fuel switching and a general economic downturn in the Utility segment's service territory.

The decrease in other operating revenues is largely related to the three-year rate settlement approved by the 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 utilized $7.6 million of the cost mitigation reserve by recording $7.6 million of other operating revenues. While the three-year rate settlement was extended for an additional year, the provisions of the settlement which gave rise to the other operating revenues in 2003 did not continue in 2004, causing other operating revenues to decrease by $7.6 million in 2004. The impact of utilizing a portion of the cost mitigation reserve in revenues in 2003 was offset by an equal amount of operation and maintenance expense and interest expense (thus there is no earnings impact). Partially offsetting this decrease in revenues, in accordance with the three-year rate settlement which ended on September 30, 2003, Distribution Corporation recorded a refund provision of $4.0 million as a reduction of other operating revenues. While the provisions of the settlement were extended for a one-year period, as previously discussed, this refund provision did not recur in 2004 because the New York rate jurisdiction's earnings did not exceed the sharing threshold. The refund provision relates to a 50% sharing with customers of earnings over a predetermined amount.

Effective September 22, 2004, Distribution Corporation stopped making off-system sales as a result of the FERC's Order 2004, "Standards of Conduct for Transmission Providers," as discussed more fully in the Rate Matters section below. As a result of this decision, Distribution Corporation most likely will not have any off-system sales in 2005.* However, due to profit sharing with retail customers, the margins resulting from off-system sales have been minimal and there should be no material impact to margins in 2005.*

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, coupled with an increase in retail sales volumes, as shown above. The increase in retail sales volumes was primarily the result of colder weather, as shown in the degree day table above. 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 the three-year rate settlement which ended on September 30, 2003, as discussed above. In 2003, Distribution Corporation utilized $7.6 million of the cost mitigation reserve by recording $7.6 million of 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 recorded 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.

Earnings

2004 Compared with 2003

The Utility segment's earnings in 2004 were $46.7 million, a decrease of $10.1 million when compared with earnings of $56.8 million in 2003. The major factors driving this decrease were an increase in pension and other post-retirement expenses of $9.9 million after tax, higher bad debt expenses of $3.8 million after tax, warmer weather in the Pennsylvania jurisdiction ($2.5 million after tax), and lower usage per customer account in the New York jurisdiction ($2.2 million after tax). These negative factors were partially offset by the absence of a refund provision in the New York jurisdiction in 2004 related to an earnings sharing mechanism in the New York jurisdiction ($2.6 million after tax), as discussed above. Other offsetting factors included a base rate increase in the Pennsylvania jurisdiction of $1.5 million after tax and lower interest expense of $4.7 million after tax.

The increase in pension and other post-retirement expenses referred to above can be attributed largely to three factors. First, in accordance with the one-year settlement extension commencing on October 1, 2003 in the New York rate jurisdiction (referred to above), the Company was required to record an additional $8.0 million before tax ($5.2 million after tax) of pension and other post-retirement expense for the year ended September 30, 2004 without a corresponding increase in revenues. Second, the Utility segment recorded $2.2 million of expense after tax associated with the settlement of a pension obligation. Third, pension and other post-retirement expenses in the Pennsylvania rate jurisdiction increased by $2.5 million after tax as the rate settlement in that jurisdiction reflected higher pension funding amounts and the amortization of previous other post-retirement deferrals.

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 2004, the WNC preserved $1.0 million of earnings since the weather was warmer than normal in the New York service territory. For 2003, the WNC reduced earnings by approximately $3.8 million because it was colder than normal in the New York service territory.

2003 Compared with 2002

The Utility segment's earnings in 2003 were $56.8 million, an increase of $7.3 million when compared with 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 remainder of the increase was primarily attributable to lower interest expense, primarily on deferred gas costs (which declined approximately $1.0 million after tax).

In 2003, the WNC reduced earnings by approximately $3.8 million because it was colder than normal in the New York service territory. For 2002, the WNC preserved earnings of approximately $9.9 million because it was warmer than normal in the New York service territory.

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 $7.30 per thousand cubic feet (Mcf) in 2004, an increase of 5% from the average cost of $6.94 per Mcf in 2003. The average cost of purchased gas in 2003 was 48% higher than the average cost of $4.68 per Mcf in 2002. 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		
	2004	2003	2002
		(Thousands)	
Firm Transportation	$120,443	$109,508	$ 88,082
Interruptible Transportation	3,084	3,944	3,315
	123,527	113,452	91,397
Firm Storage Service	63,962	63,223	62,733
Interruptible Storage Service	20	36	7
	63,982	63,259	62,740
Other	22,198	24,709	13,247
	$209,707	$201,420	$167,384

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30		
	2004	2003	2002
Firm Transportation	338,991	340,925	290,507
Interruptible Transportation	12,692	10,004	7,315
	351,683	350,929	297,822

2004 Compared with 2003

Operating revenues for the Pipeline and Storage segment increased $8.3 million in 2004 as compared with 2003. The acquisition of Empire from Duke Energy Corporation on February 6, 2003 was a significant factor contributing to the revenue increase. For 2004, Empire recorded operating revenues of $33.4 million ($32.3 million in firm transportation revenues, $0.3 million in interruptible transportation revenues and $0.8 million in other revenues). 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 $5.0 million increase in revenues from unbundled pipeline sales included in other revenues in the table above due to higher natural gas commodity prices and higher volumes. These increases to operating revenues were partially offset by lower intercompany rental income of approximately $6.5 million and lower cashout revenues of $1.3 million, both of which are 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 completely offset by purchased gas expense. 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.

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 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. 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 included in other revenues in the table above due primarily to higher natural gas commodity prices and volumes. 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.

Earnings

2004 Compared with 2003

The Pipeline and Storage segment's earnings in 2004 were $47.7 million, an increase of $2.5 million when compared with earnings of $45.2 million in 2003. The increase can be attributed primarily to the earnings impact of the increase in revenues from unbundled pipeline sales of $3.2 million after tax, discussed above, as well as the increased earnings contribution from Empire of $2.8 million. Also, Supply Corporation interest expense decreased by $1.9 million after tax. Offsetting these increases, Supply Corporation recorded $1.8 million of expense after tax associated with the settlement of a pension obligation in 2004. Supply Corporation also experienced an earnings impact associated with higher operation and maintenance expense of $1.5 million after tax.

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 ($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.

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2004	2003	2002
		(Thousands)	
Gas (after Hedging)	$167,127	$150,982	$148,467
Oil (after Hedging)	119,564	147,101	152,746
Gas Processing Plant	28,614	28,879	16,995
Other	1,815	1,308	6,627
Intrasegment Elimination(1)	(23,422)	(22,956)	(13,855)
	$293,698	$305,314	$310,980

(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		
	2004	2003	2002
Gas Production *(MMcf)*			
Gulf Coast	17,596	18,441	25,776
West Coast	4,057	4,467	4,889
Appalachia	5,132	5,123	4,402
Canada	6,228	5,774	6,387
	33,013	33,805	41,454
Oil Production *(Mbbl)*			
Gulf Coast	1,534	1,473	1,815
West Coast	2,650	2,872	3,004
Appalachia	20	10	9
Canada	324	2,382	2,834
	4,528	6,737	7,662

Average Prices

	Year Ended September 30		
	2004	2003	2002
Average Gas Price/Mcf			
Gulf Coast	$ 5.61	$ 5.41	$ 2.89
West Coast	$ 5.54	$ 5.01	$ 2.86
Appalachia	$ 5.91	$ 5.07	$ 3.74
Canada	$ 4.87	$ 4.67	$ 2.29
Weighted Average	$ 5.51	$ 5.18	$ 2.88
Weighted Average After Hedging(1)	$ 5.06	$ 4.47	$ 3.58
Average Oil Price/Barrel (bbl)			
Gulf Coast	$35.31	$29.17	$22.83
West Coast(2)	$31.89	$26.12	$19.94
Appalachia	$31.30	$28.77	$23.76
Canada	$30.94	$26.41	$19.94
Weighted Average	$32.98	$26.90	$20.63
Weighted Average After Hedging(1)	$26.40	$21.84	$19.94

(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.

2004 Compared with 2003

Operating revenues for the Exploration and Production segment decreased $11.6 million in 2004 as compared with 2003. Oil production revenue after hedging decreased $27.5 million due to a 2,209 Mbbl decline in production offset partly by higher weighted average prices after hedging ($4.56 per barrel). Most of the decrease in oil production occurred in Canada (a 2,058 Mbbl decrease) as a result of the September 2003 sale of the Company’s Southeast Saskatchewan properties, which is discussed below. Gas production revenue after hedging increased $16.1 million. Increases in the weighted average price of gas after hedging ($0.59 per Mcf) more than offset an overall decrease in gas production. Most of the decrease in gas production occurred in the Gulf Coast (an 845 MMcf decline), which is consistent with the expected decline rates in the region. Lower West Coast production (a 410 MMcf decline), down mainly due to a decline in this segment’s South Lost Hills wells, was more than offset by a 454 MMcf increase in Canadian gas production. The increase in Canadian gas production is attributable to additional drilling in East Central Alberta. The decline in the South Lost Hills wells was attributable to the maturing of the wells.

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.

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 (a 7,335 MMcf decline). The Company had anticipated some of this decline in gas and oil production due to reduced activity in 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 properties. Also, earlier in the year certain production in the Gulf Coast region was shut-in during Hurricane Lili and some of those wells did not 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.

Earnings

2004 Compared with 2003

The Exploration and Production segment's earnings in 2004 were $54.3 million, an increase of $86.2 million when compared with a loss of $31.9 million in 2003. Earnings were impacted by a few events. In 2003, the Company sold its Southeast Saskatchewan properties, recording an after tax loss of $39.6 million. In 2004, the Company recorded an adjustment to the sale of its Southeast Saskatchewan properties which increased 2004 earnings by $4.6 million. When the transaction closed in September 2003, the initial proceeds received were subject to an adjustment based on actual working capital and the resolution of certain income tax matters. Those items were resolved with the buyer in 2004 and, as a result, the Company received an additional $4.6 million of sales proceeds. The Company recorded impairment charges of $28.9 million after tax in 2003 related to its Canadian oil and gas properties. Also contributing to the increase was the fact that the loss in 2003 included a charge of $0.6 million representing the cumulative effect of a change in accounting for plugging and abandonment costs. These events sum up to $73.7 million of the overall earnings increase of $86.2 million. The remaining increase can be attributed to decreases in depletion, lease operating, and interest expense of $6.2 million after tax, $15.9 million after tax, and $1.7 million after tax, respectively, which more than offset the earnings impact of a $7.4 million decrease in oil and gas revenues, discussed above, and a $3.2 million increase in income tax expense due to a higher effective tax rate. The decrease in depletion and lease operating expenses primarily reflects the absence of the Company's former Southeast Saskatchewan properties from results of operations in 2004. The decrease in interest expense was the result of lower debt balances. The higher effective tax rate resulted from the elimination of cross-border intercompany loans in September 2003 as a result of the sale of the Southeast Saskatchewan properties.

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. Impairment charges of $28.9 million after tax 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 after tax (attributable to the production decline) and lower general and administrative expenses of $2.1 million after tax (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.

INTERNATIONAL

Revenues

International Operating Revenues

	Year Ended September 30		
	2004	2003	2002
		(Thousands)	
Heating	$ 88,395	$ 80,752	$65,386
Electricity	30,949	29,386	26,960
Other	4,081	3,932	2,969
	$123,425	$114,070	$95,315

International Heating and Electric Volumes

	Year Ended September 30		
	2004	2003	2002
Heating Sales (Gigajoules)(1)	8,538,554	8,766,567	8,689,887
Electricity Sales (megawatt hours)	936,877	973,968	972,832

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

2004 Compared with 2003

Operating revenues for the International segment increased $9.4 million in 2004 as compared with 2003. Substantially all of this increase can be attributed to an increase in the value of the Czech koruna compared to the U.S. dollar.

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 compared to the U.S. dollar.

Earnings

2004 Compared with 2003

The International segment's earnings in 2004 were $6.0 million, an increase of $15.6 million when compared with a loss of $9.6 million in 2003. Earnings were impacted by two events. During 2004, the government in the Czech Republic enacted legislation that gradually reduces the corporate statutory income tax rate from 31% to 24% over a three-year period commencing January 1, 2004. In accordance with accounting principles generally accepted in the United States of America (GAAP), the Company recorded the full benefit resulting from the change in the income tax rate ($5.2 million) as a reduction to deferred income tax expense during 2004. During 2003, the Company recorded a $8.3 million impairment charge resulting from the Company's change in accounting for goodwill, as discussed below. These two events account for $13.5 million of the earnings increase in the International segment. An increase in the value of the Czech koruna compared to the U.S. dollar improved earnings by approximately $1.1 million.

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 Republic electricity market, the Company could not be assured that the level of future cash flows from the Company's investments in the Czech Republic would 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 Czech koruna 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.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2004	2003	2002
		(Thousands)	
Natural Gas (after Hedging)	$283,747	$304,390	$151,219
Other	602	270	38
	$284,349	$304,660	$151,257

Energy Marketing Volumes

	Year Ended September 30		
	2004	2003	2002
Natural Gas — (MMcf)	41,651	45,135	33,042

2004 Compared with 2003

Operating revenues for the Energy Marketing segment decreased $20.3 million in 2004 as compared with 2003. This decrease primarily reflects lower gas sales revenue due to lower throughput, which was the result of warmer weather and the loss of several large volume but low margin customers to other marketers.

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 but low margin customers and colder weather, also contributed to the increase in operating revenues.

Earnings

2004 Compared with 2003

The Energy Marketing segment earnings in 2004 were $5.5 million, a decrease of $0.4 million when compared with earnings of $5.9 million in 2003. While margins on gas sales improved slightly, this increase was offset by expenses associated with the settlement of a pension obligation and a higher effective tax rate.

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.

TIMBER

Revenues

Timber Operating Revenues

	Year Ended September 30		
	2004	2003	2002
		(Thousands)	
Log Sales	$21,790	$27,341	$21,528
Green Lumber Sales	5,923	6,200	6,567
Kiln Dry Lumber Sales	27,416	21,814	15,976
Other	841	871	3,336
	$55,970	$56,226	$47,407

Timber Board Feet

	Year Ended September 30		
	2004	2003	2002
		(Thousands)	
Log Sales	6,848	8,764	8,174
Green Lumber Sales	9,552	11,913	12,878
Kiln Dry Lumber Sales	15,020	13,300	10,794
	31,420	33,977	31,846

2004 Compared with 2003

Operating revenues for the Timber segment did not change significantly in 2004 as compared with 2003. The decrease in log sales of $5.6 million was principally due to the Company's August 2003 sale of approximately 70,000 acres of timber properties discussed below. However, kiln dry lumber sales increased $5.6 million due to an increase in activity at the Company's mill operations. As a result of the sale of the timber properties, a larger percentage of timber processed in the Company's mills is now purchased from third parties.

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.

Earnings

2004 Compared with 2003

The Timber segment earnings in 2004 were $5.6 million, a decrease of $106.9 million when compared with earnings of $112.5 million in 2003. This earnings fluctuation is largely a reflection of the sale of timber properties discussed below. In 2003, the Company recorded a gain of $102.2 million after tax on that sale. In 2004, the Company received final timber cruise information of the properties it sold and, based on that information, determined that property records pertaining to $1.3 million ($0.8 million after tax) of timber property were not properly shown as having been transferred to the purchaser. As a result, the Company removed those assets from its property records and adjusted the previously recognized gain downward by recognizing a pre tax loss of $1.3 million. The combination of these two events caused earnings to be lower by $103.0 million. The remainder of the decrease is attributable to lower sales of cherry logs in 2004. While kiln dry lumber sales increased, this benefit was largely offset by an increase in costs associated with purchased timber.

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 a gain of approximately $102.2 million after tax. After the August sale, the Company had approximately 87,000 acres of timber property remaining.

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. In 2002, the Company wrote off it's 33⅓% equity method investment in Independence Pipeline Company. The write-off amounted to $15.2 million ($9.9 million after tax) and is recorded on the Consolidated Statement of Income as Impairment of Investment in Partnership. Aside from this impairment, income from unconsolidated subsidiaries has been relatively small, amounting to $0.8 million, $0.5 million and $0.2 million in 2004, 2003 and 2002, respectively.

INTEREST CHARGES

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

Interest on long-term debt was $8.9 million lower in 2004 compared to 2003; however, interest on long-term debt was $2.2 million higher in 2003 compared to 2002. The decrease in 2004 resulted mainly from a lower average amount of long-term debt outstanding and lower weighted average interest rates. The increase in 2003 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 $5.5 million in 2004 and $2.8 million in 2003. 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		
	2004	2003	2002
		(Millions)	
Provided by Operating Activities	$ 444.3	$ 326.8	$ 345.6
Capital Expenditures	(172.3)	(152.2)	(232.4)
Investment in Subsidiaries, Net of Cash Acquired	—	(228.8)	—
Investment in Partnerships	—	(0.4)	(0.5)
Net Proceeds from Sale of Timber Properties	—	186.0	—
Net Proceeds from Sale of Oil and Gas Producing Properties	7.1	78.5	22.1
Other Investing Activities	2.0	12.1	5.0
Short-Term Debt, Net Change	38.6	(147.6)	(224.8)
Long-Term Debt, Net Change	(243.1)	20.7	139.6
Issuance of Common Stock	23.8	17.0	10.9
Dividends Paid on Common Stock	(89.1)	(84.5)	(81.0)
Effect of Exchange Rates on Cash	3.4	1.6	1.5
Net Increase (Decrease) in Cash and Temporary Cash Investments	$ 14.7	$ 29.2	$ (14.0)

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), 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 or loss on sale of timber properties, gain or 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, options and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $444.3 million in 2004, an increase of $117.5 million compared with the $326.8 million provided by operating activities in 2003. Most of this increase occurred in the Utility segment, largely attributable to gas cost recovery timing differences.

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 $172.3 million in 2004. The table below presents these expenditures:

	Year Ended September 30, 2004 Total Expenditures For Long-Lived Assets (Millions)
Utility	$ 55.4
Pipeline and Storage	23.2
Exploration and Production	77.7
International	7.5
Timber	2.8
All Other and Corporate	5.7
	$172.3

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.

Exploration and Production

The Exploration and Production segment's capital expenditures were primarily well drilling and completion expenditures and included approximately $31.4 million for the Canadian region, $19.4 million for the Gulf Coast region, $17.4 million for the West Coast region and $9.5 million for the Appalachian region. These amounts included approximately $12.1 million spent to develop proved undeveloped reserves.

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 equipment for this segment'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.

Estimated Capital Expenditures

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

	Year Ended September 30,		
	2005	2006	2007
		(Millions)	
Utility	$ 54.0	$ 52.0	$ 51.0
Pipeline and Storage	22.0	22.0	22.0
Exploration and Production(1)	93.0	91.0	89.0
International	15.0	26.0	29.0
Timber	2.0	1.0	1.0
All Other and Corporate	5.0	—	—
	$191.0	$192.0	$192.0

(1) Includes estimated expenditures for the years ended September 30, 2005, 2006 and 2007 of approximately $14 million, $27 million and $29 million, respectively, to develop proved undeveloped reserves.

Estimated capital expenditures for the Utility segment in 2005 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 2005 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. As announced in February 2004, the Company is pursuing a project to expand its natural gas pipeline operations to serve new markets in New York and elsewhere in the Northeast by extending the Empire State Pipeline.* This proposed extension project would provide an upstream supply link for Phase I of the Millennium Pipeline and will transport Canadian and other natural gas supplies to downstream customers, including KeySpan Gas East Corporation, which has entered into a precedent agreement to be a major shipper, subject to the satisfaction of various conditions.* The pipeline extension will be designed to move at least 250 MMcf of natural gas per day.* The preliminary estimate of the cost for developing the Empire extension project is $140 million and the targeted in-service date is late in calendar 2006.* The estimated capital expenditures do not include any expenditures for the Empire extension project. As of September 30, 2004, the Company had incurred approximately $0.6 million in costs (all of which have been reserved) related to this project.

Estimated capital expenditures in 2005 for the Exploration and Production segment include approximately $32.0 million for Canada, $29.0 million for the Gulf Coast region ($28.0 million on the off-shore program in the Gulf of Mexico), $20.0 million for the West Coast region and $12.0 million for the Appalachian region.*

The estimated capital expenditures for the International segment in 2005 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 currently include one project in Italy and one project in 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 100-megawatt gas-fired combined-cycle plants. The estimated cost of this project is $200.0 million to $220.0 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.*

Estimated capital expenditures in the All Other and Corporate category will be concentrated on the purchase of equipment for a 55-megawatt electric generation facility in Buffalo, New York combined with capital improvements to the Company's corporate headquarters.

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 natural gas storage facilities and the expansion of natural gas 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 2004 and August 2004, the Company repaid $125.0 million of maturing 7.75% debentures at par and $100.0 million of maturing 6.82% medium-term notes at par, respectively. The Company used available cash and short-term borrowings to repay this debt.

Consolidated short-term debt increased $38.6 million during 2004. Although a certain amount of short-term borrowings were initially used to repay the maturing debt discussed above, the Company was able to use cash flow from operations to repay most of this additional short-term debt. 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, 2004, the Company had outstanding short-term notes payable to banks and commercial paper of $26.5 million and $130.3 million, respectively. The Company has SEC authorization under the Holding Company Act 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 $400.0 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 syndicated committed credit facility totaling $220.0 million. Of that amount, $110.0 million is committed to the Company through September 25, 2005 and $110.0 million is committed to the Company through September 30, 2005. The Company anticipates that it will be able to replace this facility at or before its maturity.*

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 .625 from October 1, 2003 through September 30, 2004 and .60 from October 1, 2004 and thereafter. At September 30, 2004, the Company's debt to capitalization ratio (as calculated under the facility) was .51. The constraints specified in the committed credit facility would permit an additional $576.0 million in short-term and/or long-term debt to be outstanding before the Company's debt to capitalization ratio would exceed .60. 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, 2004, the Company would have been permitted to issue up to a maximum of $713.0 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 1974 indenture pursuant to which $399.0 million (or 35%) of the Company's long-term debt (as of September 30, 2004) 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 under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $220.0 million, committed 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 any of its significant subsidiaries fails 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 any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2004, the Company had no debt outstanding under the committed credit facility.

The Company's embedded cost of long-term debt was 6.4% at September 30, 2004 and 6.5% at September 30, 2003. 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, in an order 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. The Company has an effective registration statement on file with the SEC under which it has available capacity to issue an additional $550.0 million of debt and equity securities under the Securities Act of 1933, and within the authorization granted by the SEC under the Holding Company Act. 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 $34.3 million. These leases have been entered into for the use of buildings, 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 $10.0 million. The Company has guaranteed 50%, or $5.0 million, of these capital lease commitments.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2004, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2005	2006	2007	2008	2009	Thereafter	Total
				(Millions)			
Long-Term Debt	$ 14.3	$ 14.3	$ 9.3	$209.3	$104.1	$796.3	$1,147.6
Short-Term Bank Notes	$ 26.5	$ —	$ —	$ —	$ —	$ —	$ 26.5
Commercial Paper	$130.3	$ —	$ —	$ —	$ —	$ —	$ 130.3
Operating Lease Obligations	$ 8.7	$ 7.1	$ 6.1	$ 5.2	$ 4.8	$ 2.4	$ 34.3
Capital Lease Obligations	$ 0.8	$ 1.1	$ 0.9	$ 0.8	$ 0.4	$ 1.0	$ 5.0
Purchase Obligations:							
Gas Purchase Contracts(1)	$589.5	$ 87.0	$ 11.1	$ 5.8	$ 5.7	$ 68.4	$ 767.5
Transportation and Storage Contracts	$134.4	$135.4	$133.0	$125.9	$ 69.5	$ 12.4	$ 610.6
Other	$ 2.4	$ 0.8	$ 0.4	$ 0.4	$ 0.4	$ —	$ 4.4

(1) Gas prices are variable based on the NYMEX prices adjusted for basis.

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 the Financial Accounting Standards Board's Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (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 and anticipates that it will continue making contributions to the Retirement Plan.* During 2004, the Company contributed $37.1 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2005 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.*

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 has been making contributions to the Post-Retirement Plan over the last several years and anticipates that it will continue making contributions to the Post-Retirement Plan.* During 2004, the Company contributed $39.7 million to the Post-Retirement Plan. The Company anticipates that the annual contribution to the Post-Retirement Plan in 2005 will be in the range of $30.0 million to $40.0 million.* The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.*

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, options and futures contracts, as part of the Company's overall energy commodity price risk management strategy. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from or pay to the respective counterparties at September 30, 2004 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, 2004. At September 30, 2004, 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					
	2005	2006	2007	2008	2009	Total
Notional Quantities (Equivalent Bcf)	11.3	8.4	1.8	1.2	0.3	23.0
Weighted Average Fixed Rate (per Mcf)	$5.47	$5.68	$5.02	$4.80	$4.81	$5.47
Weighted Average Variable Rate (per Mcf)	$7.12	$6.74	$6.13	$5.58	$5.50	$6.81

Crude Oil Price Swap Agreements

	Expected Maturity Dates			
	2005	2006	2007	Total
Notional Quantities (Equivalent bbls)	2,743,000	1,755,000	540,000	5,038,000
Weighted Average Fixed Rate (per bbl)	$30.51	$33.27	$35.55	$32.01
Weighted Average Variable Rate (per bbl)	$46.74	$41.31	$38.41	$43.95

At September 30, 2004, the Company would have had to pay its respective counterparties an aggregate of approximately $25.0 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have had to pay an aggregate of approximately $57.2 million to its counterparties to terminate the crude oil price swap agreements outstanding at September 30, 2004.

At September 30, 2003, the Company had natural gas price swap agreements covering 13.1 Bcf at a weighted average fixed rate of $4.24 per Mcf. The Company also had crude oil price swap agreements covering 2,184,000 bbls at a weighted average fixed rate of $25.44 per bbl. The increase in price swap agreements from September 2003 to September 2004 is largely a result of management's decision to hedge farther into the future in the Exploration and Production segment given the high commodity prices available. It is also a reflection of management's decision to use crude oil price swap agreements instead of crude oil no cost collars in the Exploration and Production segment, as discussed below.

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, 2004, the Company had not entered into any natural gas or crude oil no cost collars extending beyond 2006.

No Cost Collars

	Expected Maturity Dates		
	2005	**2006**	**Total**
Natural Gas			
Notional Quantities (Equivalent Bcf)	5.1	0.4	5.5
Weighted Average Ceiling Price (per Mcf)	$8.31	$7.88	$8.28
Weighted Average Floor Price (per Mcf)	$4.94	$4.77	$4.93
Crude Oil			
Notional Quantities (Equivalent bbls)	105,000	—	105,000
Weighted Average Ceiling Price (per bbl)	$28.56	—	$28.56
Weighted Average Floor Price (per bbl)	$25.00	—	$25.00

At September 30, 2004, the Company would have had to pay an aggregate of approximately $1.6 million to terminate the natural gas no cost collars outstanding at that date. The Company would have had to pay an aggregate of approximately $2.1 million to terminate the crude oil no cost collars outstanding at that date.

At September 30, 2003, the Company had natural gas no cost collars covering 3.7 Bcf at 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 crude oil no cost collars covering 1,290,000 bbls at a weighted average floor price of $23.91 per bbl and a weighted average ceiling price of $28.00 per bbl. The increase in natural gas no cost collars from September 2003 to September 2004 is a result of management's decision to hedge farther out into the future in the Exploration and Production segment given the high commodity prices available. The decrease in crude oil no cost collars from September 2003 to September 2004 is a result of management's decision to use crude oil price swap agreements instead of crude oil no cost collars to hedge future crude oil production in the Exploration and Production segment. With the current commodity price environment, management determined that it could better meet its commodity price objectives through the use of price swap agreements.

Options

The following table discloses the notional quantities and weighted average strike prices by expected maturity dates for options used by the Exploration and Production segment to manage natural gas price risk. The put options provide for the Company to receive monthly payments from other parties when a variable price falls below an established floor or "strike" price. The call options provide for the Company to pay monthly payments to other parties when a variable price rises above an established ceiling or "strike" price. At September 30, 2004, the Company held no options with maturity dates extending beyond 2006.

	Expected Maturity Dates		
	2005	2006	Total
Natural Gas Put Options Purchased			
Notional Quantities (Equivalent Bcf)	0.8	0.3	1.1
Weighted Average Strike Price (per Mcf)	$6.05	$5.83	$5.99
Natural Gas Call Options Sold			
Notional Quantities (Equivalent Bcf)	0.8	0.3	1.1
Weighted Average Strike Price (per Mcf)	$7.84	$8.69	$8.06

At September 30, 2004, the Company would have received from the respective counterparties an aggregate of approximately $0.2 million to terminate the put options outstanding at that date. The Company would have had to pay an aggregate of approximately $1.0 million to terminate the call options outstanding at that date. The Company did not have any options outstanding at September 30, 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, 2004, the Company held no futures contracts with maturity dates extending beyond 2007.

Futures Contracts

	Expected Maturity Dates			
	2005	2006	2007	Total
Net Contract Volumes Purchased (Sold) (Equivalent Bcf)	(3.5)	(0.4)	0.1	(3.8)
Weighted Average Contract Price (per Mcf)	$6.16	$6.29	$5.88	$6.17
Weighted Average Settlement Price (per Mcf)	$7.74	$6.96	$6.33	$7.69

At September 30, 2004, the Company would have had to pay $6.2 million to terminate these futures contracts.

At September 30, 2003, the Company had futures contracts covering 3.6 Bcf (net long position) at a weighted average contract price of $5.60 per Mcf. The change from a net long position at September 30, 2003 to a net short position at September 30, 2004 can largely be explained by the high commodity price environment experienced by the Energy Marketing segment in 2004. With high commodity prices, customers have been reluctant to enter into fixed price sales commitments. With fewer fixed price sales commitments, the Energy Marketing segment has purchased fewer contracts since it no longer faces as great a risk of commodity price increases.

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 derivatives. At September 30, 2004, the Company used seven counterparties for its over the counter derivatives. At September 30, 2004, no individual counterparty represented greater than 20% 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 Sheets. 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 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, 2004, these instruments consisted of domestic short-term bank loans and commercial paper totaling $156.8 million. The interest rate on these short-term bank loans and commercial paper approximated 1.8% at September 30, 2004.

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, 2004:

	Principal Amounts by Expected Maturity Dates						
	2005	2006	2007	2008	2009	Thereafter	Total
	(Dollars in Millions)						
National Fuel Gas Company							
Long-Term Fixed Rate Debt	$ —	$ —	$ —	$200	$100	$796.3	$1,096.3
Weighted Average Interest Rate Paid	0%	0%	0%	6.3%	6.0%	6.5%	6.4%
Fair Value = $1,147.9 million							
Other Notes							
Long-Term Debt(1)	$14.3	$14.3	$9.3	$ 9.3	$ 4.1	$ —	$ 51.3
Weighted Average Interest Rate Paid(2)	4.1%	4.1%	2.8%	2.8%	2.8%	—	3.5%
Fair Value = $51.3 million							

(1) $41.4 million is variable rate debt; $9.9 million is fixed rate debt.

(2) Weighted average interest rate excludes the impact of an interest rate collar on $41.4 million of variable rate debt.

The Company uses an interest rate collar to limit interest rate fluctuations on $41.4 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 $2.2 million to terminate the interest rate collar at September 30, 2004.

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. 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 continued existing base rates, but reduced the level above which earnings are shared 50/50 with customers from the previous 11.5% return on equity to 11.0%. In addition, the Settlement increased the combined pension and other post-retirement benefit expense by $8.0 million, without a corresponding increase in revenues. Most other features of Distribution Corporation's service remained largely unchanged. In April 2004, Distribution Corporation commenced confidential settlement negotiations with the NYPSC and other parties concerning, among other things, its revenue requirement for the year ending September 30, 2005. Those settlement discussions failed to produce an agreement prior to the expiration of the Settlement. On August 27, 2004, Distribution Corporation filed proposed tariff amendments and supporting testimony designed to increase its annual revenues by $41.3 million beginning October 1, 2004. The rate request was filed to address throughput reductions and increased operating costs such as uncollectibles and personnel expenses. In accordance with standard rate case procedure, the NYPSC suspended Distribution Corporation's filing as provided by law in order to allow time for an investigation and hearings. Following hearings and further proceedings, the Commission will issue an order approving, rejecting or modifying Distribution Corporation's rate request for an anticipated effective date of late July, 2005. Distribution Corporation is unable to ascertain the outcome of the rate proceeding at this time. The existing base rates and other provisions of the Settlement that expired on September 30, 2004 will continue to be in effect until the Commission issues an order concerning Distribution Corporation's rate request.

On June 1, 2004, Distribution Corporation submitted a filing to the NYPSC supporting the removal of a $5 million annual bill credit originally established under the terms of the Agreement. The filing requested removal of the bill credit effective October 1, 2004. On September 28, 2004, the NYPSC issued an order rejecting Distribution Corporation's request for the stated reason that Distribution Corporation's earnings were adequate, in the NYPSC's opinion, without removal of the bill credit. Distribution Corporation is contemplating further action on the NYPSC's order.

In another order issued on September 28, 2004, the NYPSC directed the continuation, with modification, of four programs under the Settlement that were scheduled to expire on September 30, 2004. The effect of the NYPSC's order was to unilaterally extend the terms of the Settlement without Distribution Corporation's consent. Although the NYPSC's order stated that it provided for funding of the programs, Distribution Corporation petitioned Supreme Court, Albany County for an injunction to allow the programs to expire on their own terms. Distribution Corporation's petition was partially successful, and the proceeding remains pending.

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. On December 3, 2001, Distribution Corporation filed its response which vigorously asserted that the allegations lacked merit. Distribution Corporation continues to so believe. On July 28, 2004, the NYPSC concluded the investigation of issues raised in the order without assessing any fines or penalties. As part of the settlement of the NYPSC's investigation, Distribution Corporation will commit $1.5 million to a new program designed to assist low-income customers who are transitioning from public assistance. Distribution Corporation has also agreed to incur costs up to $0.3 million for an audit of customer service practices. The NYPSC has agreed not to seek any penalties should any violations be uncovered during the audit. 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 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, 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 other post-retirement benefit expenses. The settlement was approved by the PaPUC on December 18, 2003, and rates became effective January 15, 2004.

On September 15, 2004, Distribution Corporation filed revised tariffs with the PaPUC to increase annual revenues by $22.8 million to cover increases in the cost of service to be effective November 14, 2004. The rate request was filed to address throughput reductions and increased operating costs such as uncollectibles and personnel expenses. Applying standard procedure, the PaPUC suspended Distribution Corporation's tariff filing to perform an investigation and hold hearings. With this suspension, the effective date was changed to June 14, 2005 and the proceeding remains pending.

Pipeline and Storage

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

On November 25, 2003, the FERC issued Order 2004 "Standards of Conduct for Transmission Providers" ("Order 2004"). Order 2004 was clarified in Order 2004-A on April 16, 2004 and Order 2004-B on August 2, 2004. Order 2004, which went into effect September 22, 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. Supply Corporation's principal energy affiliates will be Seneca, NFR and, possibly, Distribution Corporation.* Order 2004 provides that companies may request waivers, which the Company has done with respect to Distribution Corporation and is awaiting rulings. Order 2004 also provides an exemption for local distribution companies that are affiliated with interstate pipelines (such as Distribution Corporation), but the exemption is limited, with very minor exceptions, to local distribution corporations that do not make any off-system sales and do not purchase gas in ways FERC considers to be "financial or futures transactions or hedging." While Distribution Corporation stopped making such off-system sales effective September 22, 2004, some of its gas purchase arrangements might be considered by FERC to be "financial or futures transactions or hedging." Supply Corporation and Distribution Corporation would like to continue operating as they do, whether by waiver, amendment or further clarification of the new rules, or by complying with the requirements applicable if Distribution Corporation were an energy affiliate. Treating Distribution Corporation as an energy affiliate, without any waivers, would require changes in the way Supply Corporation and Distribution Corporation operate which would decrease efficiency, but probably would not increase capital or operating expenses to an extent that would be material to the financial condition of the Company.* Until there is further clarification from the FERC on the scope of these exemptions and rulings on the Company's waiver requests, the Company is unable to predict the ultimate impact Order 2004 will have on the Company. As previously mentioned, Distribution Corporation stopped making off-system sales, effective September 22, 2004. The Company does not expect that change to have a material effect on the Company's results of operations, as margins resulting from off-system sales are minimal as a result of profit sharing with retail customers.*

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.

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 $14.0 million.* This liability has been recorded on the Consolidated Balance Sheet at September 30, 2004. 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."

NEW ACCOUNTING PRONOUNCEMENTS

In September 2004, the SEC issued Staff Accounting Bulletin No. 106 (SAB 106). SAB 106 addresses the application of SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143) to companies that follow the full-cost method of accounting for oil and gas property acquisition, exploration and development costs. For a discussion of SAB 106 and its impact on the Company, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

EFFECTS OF INFLATION

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

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, franchises, permits, 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 effect of such changes on the accounting treatment or valuation of financial instruments for the Company's natural gas and oil reserves;
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;
23. The cost and effects of legal and administrative claims against the Company;
24. Changes in actuarial assumptions and the return on assets with respect to the Company's retirement plan and post-retirement benefit plans;
25. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide post-retirement benefits; or
26. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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***

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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 INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2004 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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
December 9, 2004

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2004	2003	2002
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$2,031,393	$2,035,471	$1,464,496
Operating Expenses:			
Purchased Gas	949,452	963,567	462,857
Fuel Used in Heat and Electric Generation	65,722	61,029	50,635
Operation and Maintenance	413,593	386,270	394,157
Property, Franchise and Other Taxes	72,111	82,504	72,155
Depreciation, Depletion and Amortization	189,538	195,226	180,668
Impairment of Oil and Gas Producing Properties	—	42,774	—
	1,690,416	1,731,370	1,160,472
Gain (Loss) on Sale of Timber Properties	(1,252)	168,787	—
Gain (Loss) on Sale of Oil and Gas Producing Properties	4,645	(58,472)	—
Operating Income	344,370	414,416	304,024
Other Income (Expense):			
Income from Unconsolidated Subsidiaries	805	535	224
Impairment of Investment in Partnership	—	—	(15,167)
Other Income	6,671	6,887	7,017
Interest Expense on Long-Term Debt	(83,827)	(92,766)	(90,543)
Other Interest Expense	(6,763)	(12,290)	(15,109)
Income Before Income Taxes and Minority Interest in Foreign Subsidiaries	261,256	316,782	190,446
Income Tax Expense	92,737	128,161	72,034
Minority Interest in Foreign Subsidiaries	(1,933)	(785)	(730)
Income Before Cumulative Effect of Changes In Accounting	166,586	187,836	117,682
Cumulative Effect of Changes in Accounting	—	(8,892)	—
Net Income Available for Common Stock	166,586	178,944	117,682
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	642,690	549,397	513,488
	809,276	728,341	631,170
Dividends on Common Stock	90,350	85,651	81,773
Balance at End of Year	$ 718,926	$ 642,690	$ 549,397
Earnings Per Common Share:			
Basic:			
Income Before Cumulative Effect of Changes in Accounting	$ 2.03	$ 2.32	$ 1.47
Cumulative Effect of Changes in Accounting	—	(0.11)	—
Net Income Available for Common Stock	$ 2.03	$ 2.21	$ 1.47
Diluted:			
Income Before Cumulative Effect of Changes in Accounting	$ 2.01	$ 2.31	$ 1.46
Cumulative Effect of Changes in Accounting	—	(0.11)	—
Net Income Available for Common Stock	$ 2.01	$ 2.20	$ 1.46
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	82,045,535	80,808,794	79,821,430
Used in Diluted Calculation	82,900,438	81,357,896	80,534,453

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30, 2004	At September 30, 2003
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$4,602,779	$4,657,343
Less — Accumulated Depreciation, Depletion and Amortization	1,596,015	1,666,295
	3,006,764	2,991,048
Current Assets		
Cash and Temporary Cash Investments	66,153	51,421
Receivables — Net of Allowance for Uncollectible Accounts of $17,440 and $17,943, Respectively	129,825	136,604
Unbilled Utility Revenue	18,574	20,155
Gas Stored Underground	68,511	89,640
Materials and Supplies — at average cost	43,922	32,311
Unrecovered Purchased Gas Costs	7,532	28,692
Prepayments	38,760	46,860
Fair Value of Derivative Financial Instruments	23	1,698
	373,300	407,381
Other Assets		
Recoverable Future Taxes	83,847	84,818
Unamortized Debt Expense	19,573	22,119
Other Regulatory Assets	66,862	52,381
Deferred Charges	3,411	7,528
Other Investments	72,556	64,025
Investments in Unconsolidated Subsidiaries	16,444	16,425
Goodwill	5,476	5,476
Intangible Assets	45,994	49,664
Other	17,571	18,195
	331,734	320,631
Total Assets	$3,711,798	$3,719,060
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value Authorized — 200,000,000 Shares; Issued and Outstanding — 82,990,340 Shares and 81,438,290 Shares, Respectively	$ 82,990	$ 81,438
Paid In Capital	506,560	478,799
Earnings Reinvested in the Business	718,926	642,690
Total Common Shareholder Equity Before Items Of Other Comprehensive Loss	1,308,476	1,202,927
Accumulated Other Comprehensive Loss	(54,775)	(65,537)
Total Comprehensive Shareholders' Equity	1,253,701	1,137,390
Long-Term Debt, Net of Current Portion	1,133,317	1,147,779
Total Capitalization	2,387,018	2,285,169
Minority Interest in Foreign Subsidiaries	37,048	33,281
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	156,800	118,200
Current Portion of Long-Term Debt	14,260	241,731
Accounts Payable	115,979	118,563
Amounts Payable to Customers	3,154	692
Other Accruals and Current Liabilities	91,164	52,851
Fair Value of Derivative Financial Instruments	95,099	17,928
	476,456	549,965
Deferred Credits		
Accumulated Deferred Income Taxes	458,095	423,282
Taxes Refundable to Customers	11,065	13,519
Unamortized Investment Tax Credit	7,498	8,199
Cost of Removal Regulatory Liability	82,020	76,782
Other Regulatory Liabilities	67,669	72,632
Pension Liability	91,587	153,240
Asset Retirement Obligation	32,292	27,493
Other Deferred Credits	61,050	75,498
	811,276	850,645
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$3,711,798	$3,719,060

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended September 30		
	2004	2003	2002
	(Thousands of dollars)		
Operating Activities			
Net Income Available for Common Stock	$ 166,586	$ 178,944	$ 117,682
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
(Gain) Loss on Sale of Timber Properties	1,252	(168,787)	—
(Gain) Loss on Sale of Oil and Gas Producing Properties	(4,645)	58,472	—
Impairment of Oil and Gas Producing Properties	—	42,774	—
Depreciation, Depletion and Amortization	189,538	195,226	180,668
Deferred Income Taxes	40,329	78,369	62,013
Impairment of Investment in Partnership	—	—	15,167
Cumulative Effect of Changes in Accounting	—	8,892	—
(Income) Loss from Unconsolidated Subsidiaries, Net of Cash Distributions	(19)	703	361
Minority Interest in Foreign Subsidiaries	1,933	785	730
Other	9,839	11,289	9,842
Change in:			
Receivables and Unbilled Utility Revenue	4,840	(28,382)	40,786
Gas Stored Underground and Materials and Supplies	9,860	(12,421)	8,717
Unrecovered Purchased Gas Costs	21,160	(16,261)	(8,318)
Prepayments	8,146	(2,773)	(1,737)
Accounts Payable	(5,134)	13,699	(24,025)
Amounts Payable to Customers	2,462	692	(51,223)
Other Accruals and Current Liabilities	38,718	8,595	(27,332)
Other Assets	(10,693)	(32,681)	11,869
Other Liabilities	(29,872)	(10,298)	10,350
Net Cash Provided by Operating Activities	444,300	326,837	345,550
Investing Activities			
Capital Expenditures	(172,341)	(152,251)	(232,368)
Investment in Subsidiaries, Net of Cash Acquired	—	(228,814)	—
Investment in Partnerships	—	(375)	(536)
Net Proceeds from Sale of Timber Properties	—	186,014	—
Net Proceeds from Sale of Oil and Gas Producing Properties	7,162	78,531	22,068
Other	1,974	12,065	5,012
Net Cash Used in Investing Activities	(163,205)	(104,830)	(205,824)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	38,600	(147,622)	(224,845)
Net Proceeds from Issuance of Long-Term Debt	—	248,513	243,844
Reduction of Long-Term Debt	(243,085)	(227,826)	(104,212)
Proceeds from Issuance of Common Stock	23,763	17,019	10,915
Dividends Paid on Common Stock	(89,092)	(84,530)	(80,974)
Net Cash Used in Financing Activities	(269,814)	(194,446)	(155,272)
Effect of Exchange Rates on Cash	3,451	1,644	1,535
Net Increase (Decrease) in Cash and Temporary Cash Investments	14,732	29,205	(14,011)
Cash and Temporary Cash Investments At Beginning of Year	51,421	22,216	36,227
Cash and Temporary Cash Investments At End of Year	$ 66,153	$ 51,421	$ 22,216
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			
Interest	$ 90,705	$ 104,452	$ 100,397
Income Taxes	$ 30,214	$ 56,146	$ 29,985

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2004	2003	2002
	(Thousands of dollars)		
Net Income Available for Common Stock	$ 166,586	$178,944	$117,682
Other Comprehensive Income (Loss), Before Tax:			
Minimum Pension Liability Adjustment	56,612	(86,170)	(52,977)
Foreign Currency Translation Adjustment	21,466	54,472	24,278
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	3,629	2,419	(2,086)
Unrealized Loss on Derivative Financial Instruments Arising During the Period	(129,934)	(47,777)	(42,584)
Reclassification Adjustment for Realized (Gain) Loss on Derivative Financial Instruments in Net Income	49,142	69,809	(20,063)
Other Comprehensive Income (Loss), Before Tax	915	(16,854)	(93,432)
Income Tax Expense (Benefit) Related to Minimum Pension Liability Adjustment	19,814	(30,159)	(18,542)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	1,270	847	(730)
Income Tax Benefit Related to Unrealized Loss on Derivative Financial Instruments Arising During the Period	(49,113)	(18,594)	(17,341)
Reclassification Adjustment for Income Tax (Expense) Benefit on Realized (Gain) Loss on Derivative Financial Instruments in Net Income	18,182	26,953	(8,040)
Income Taxes — Net	(9,847)	(20,953)	(44,653)
Other Comprehensive Income (Loss)	10,762	4,099	(48,779)
Comprehensive Income	$ 177,348	$183,043	$ 68,903

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

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 segment records 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, International and Energy Marketing segments record revenue as bills are rendered for service supplied on a calendar month basis. The International segment also records monthly revenue on an estimated basis for certain heating customers. The customers make estimated payments on a monthly basis and a final true-up and bill is rendered at the end of the calendar year. 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 and September 30, 2003. The Company recognized impairments of $31.8 million and $11.0 million at June 30, 2003 and September 30, 2003, respectively.

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 actual 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	
	2004	2003
	(Thousands)	
Utility	$1,426,540	$1,380,278
Pipeline and Storage	946,866	854,923
Exploration and Production	1,517,856	1,673,827
International	379,356	349,132
Energy Marketing	1,169	1,159
Timber	97,290	96,315
All Other and Corporate	28,442	20,541
	$4,397,519	$4,376,175

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2004	2003	2002
Utility	2.8%	2.8%	2.8%
Pipeline and Storage	4.1%	4.4%	3.6%
Exploration and Production, per Mcfe(1)	$1.49	$1.34	$1.19
International	4.2%	4.2%	4.2%
Energy Marketing	8.7%	10.9%	16.4%
Timber	6.5%	7.0%	3.2%
All Other and Corporate	6.2%	1.7%	2.7%

(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 $1.47, $1.30 and $1.16 per Mcfe of production in 2004, 2003 and 2002, respectively.

Cumulative Effect of Changes in Accounting

Effective October 1, 2002, the Company adopted 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):

	Year Ended September 30	
	2004	2003
	(Thousands)	
Balance at Beginning of Year	$27,493	$ 36,090
Liabilities Incurred and Revisions of Estimates	3,510	242
Liabilities Settled	(831)	(13,227)
Accretion Expense	1,933	2,602
Exchange Rate Impact	187	1,786
Balance at End of Year	$32,292	$ 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, 2004 and 2003, the costs of removal reclassified to other regulatory liabilities amounted to $82.0 million and $76.8 million, respectively.

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 was 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 could not be assured that the level of future cash flows from the Company's investments in the Czech Republic would attain the level that was originally forecasted. In accordance with SFAS 142, this impairment was reported as a cumulative effect of change in accounting. Goodwill amortization amounted to $0.6 million in 2002.

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, options and futures contracts. 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 Sheets 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 Sheets. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statements of Income. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2004, 2003 or 2002. 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 Statements 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 Statements of Income. However, in the case of fair value hedges, the Company also records an asset or liability on the Consolidated Balance Sheets 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 Statements 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 2004, 2003 or 2002.

Accumulated Other Comprehensive Income (Loss)

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

	Year Ended September 30	
	2004	2003
	(Thousands)	
Minimum Pension Liability Adjustment	$(53,648)	$(90,446)
Cumulative Foreign Currency Translation Adjustment	51,516	30,050
Net Unrealized Loss on Derivative Financial Instruments	(56,733)	(6,872)
Net Unrealized Gain on Securities Available for Sale	4,090	1,731
Accumulated Other Comprehensive Loss	$(54,775)	$(65,537)

At September 30, 2004, it is estimated that $45.4 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 2005. 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 $46.6 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 2004, 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 $113.3 million at September 30, 2004. 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 and exchange-traded options. The amounts held in margin accounts amounted to $8.6 million and $1.5 million at September 30, 2004 and 2003, 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 2004, 2003 and 2002, 2,296,828, 7,789,688 and 5,260,633 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, 2004, 2003 and 2002. 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		
	2004	**2003**	**2002**
	(Thousands, except per share amounts)		
Net Income Available for Common Stock As Reported	$166,586	$178,944	$117,682
Deduct: Total Compensation Expense Determined Based on Fair Value at the Grant Dates	1,318	3,105	4,641
Pro Forma Net Income Available for Common Stock	$165,268	$175,839	$113,041
Earnings Per Common Share:			
Basic — As Reported	$ 2.03	$ 2.21	$ 1.47
Basic — Pro Forma	$ 2.01	$ 2.18	$ 1.42
Diluted — As Reported	$ 2.01	$ 2.20	$ 1.46
Diluted — Pro Forma	$ 1.99	$ 2.16	$ 1.40

The weighted average fair value per share of options granted in 2004, 2003 and 2002 was $4.66, $4.17 and $4.32, 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		
	2004	**2003**	**2002**
Quarterly Dividend Yield	1.12%	1.10%	1.07%
Annual Standard Deviation (Volatility)	21.77%	22.24%	21.83%
Risk Free Rate	4.61%	3.33%	4.88%
Expected Term — in Years	7.0	6.5	5.5

New Accounting Pronouncements

In September 2004, the SEC issued SAB 106. SAB 106 addresses the application of SFAS 143 to companies that follow the full cost method of accounting for oil and gas property acquisition, exploration and development costs. SAB 106 states that after adoption of SFAS 143, the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation. The Company adopted SAB 106 for purposes of the full cost ceiling calculation at September 30, 2004. The adoption of SAB 106 did not have any impact on the Company's financial statements and did not have a material effect on the results of the ceiling test calculation.

Note B — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2004	2003
	(Thousands)	
Regulatory Assets(1):		
Recoverable Future Taxes (Note C)	$ 83,847	$ 84,818
Unrecovered Purchased Gas Costs (See Regulatory Mechanisms in Note A)	7,532	28,692
Unamortized Debt Expense (Note A)	9,882	11,364
Pension and Post-Retirement Benefit Costs (2)(Note F)	62,664	47,750
Other(2)	4,198	4,631
Total Regulatory Assets	168,123	177,255
Regulatory Liabilities:		
Cost of Removal Regulatory Liability (See Cumulative Effect Discussion in Note A)	82,020	76,782
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	3,154	692
New York Rate Settlements(3)	26,048	30,900
Taxes Refundable to Customers (Note C)	11,065	13,519
Pension and Post-Retirement Benefit Costs(3) (Note F)	13,232	23,719
Other(3)	28,389	18,013
Total Regulatory Liabilities	163,908	163,625
Net Regulatory Position	$ 4,215	$ 13,630

(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 $12.0 million and $11.4 million at September 30, 2004 and 2003, respectively. Other aspects of the settlements include a special reserve of $3.5 million and $5.4 million at September 30, 2004 and 2003, respectively, to be applied against the Company's incremental costs resulting from the

NYPSC's gas restructuring effort and a "cost mitigation reserve" of $5.6 million and $8.2 million at September 30, 2004 and 2003, 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 $4.9 million and $5.9 million at September 30, 2004 and 2003, 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		
	2004	2003	2002
		(Thousands)	
Operating Expenses:			
Current Income Taxes —			
Federal	$42,502	$ 37,335	$ 7,743
State	7,871	11,990	1,384
Foreign	2,035	467	894
Deferred Income Taxes —			
Federal	29,559	53,311	50,205
State	9,620	12,983	9,968
Foreign	1,150	12,075	1,840
	92,737	128,161	72,034
Other Income:			
Deferred Investment Tax Credit	(697)	(693)	(697)
Minority Interest in Foreign Subsidiaries	374	(566)	(277)
Cumulative Effect of Change in Accounting	—	(354)	—
Total Income Taxes	$92,414	$126,548	$71,060

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

	Year Ended September 30		
	2004	2003	2002
		(Thousands)	
U.S.	$232,928	$383,695	$180,349
Foreign	26,072	(78,202)	8,394
	$259,000	$305,493	$188,743

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		
	2004	2003	2002
		(Thousands)	
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$90,650	$106,923	$66,060
Increase (Reduction) in Taxes Resulting from:			
State Income Taxes	11,369	16,232	7,379
Foreign Tax Differential	(1,166)	3,318	(481)
Foreign Tax Rate Reduction	(5,174)	—	—
Miscellaneous	(3,265)	75	(1,898)
Total Income Taxes	$92,414	$126,548	$71,060

Legislation was enacted in the Czech Republic which reduces the corporate statutory income tax rate from 31% to 24% over a three-year period. The foreign tax rate reduction amount shown above reflects a reduction in deferred income taxes that were provided in prior years when a higher statutory tax rate was in effect.

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

	At September 30	
	2004	2003
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 568,114	$ 519,578
Other	37,051	21,532
Total Deferred Tax Liabilities	605,165	541,110
Deferred Tax Assets:		
Minimum Pension Liability Adjustment	(28,887)	(48,701)
Capital Loss Carryover	(12,546)	(18,607)
Unrealized Hedging Losses	(33,890)	(4,509)
Other	(74,624)	(52,368)
	(149,947)	(124,185)
Valuation Allowance	2,877	6,357
Total Deferred Tax Assets	(147,070)	(117,828)
Total Net Deferred Income Taxes	$ 458,095	$ 423,282

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 $11.1 million and $13.5 million at September 30, 2004 and 2003, 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 $83.8 million and $84.8 million at September 30, 2004 and 2003, respectively.

The Company has undistributed earnings of foreign subsidiaries that relate to its operations in the Czech Republic. These earnings 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. At September 30, 2004, such undistributed earnings totaled $49.6 million. In addition, there was a $35.8 million positive cumulative translation adjustment attributable to this investment, and similarly, no U.S. income taxes have been provided thereon.

The American Jobs Creation Act of 2004 was signed into law on October 22, 2004. The Company is reviewing the aspects of this legislation which affect, or will affect, the Company's various segments, including the provision providing a substantially reduced tax rate of 5.25% on certain dividends received from foreign affiliates. This provision is effective, at the election of the Company, for foreign dividends received in either 2005 or 2006.

A capital loss carryover of $36 million exists at September 30, 2004, 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

	Common Stock		Paid In	Earnings Reinvested in the	Accumulated Other Comprehensive
	Shares	Amount	Capital	Business	Income (Loss)
	(Thousands, except per share amounts)				
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	(65,537)
Net Income Available for Common Stock				166,586	
Dividends Declared on Common Stock ($1.10 Per Share)				(90,350)	
Other Comprehensive Income, Net of Tax					10,762
Common Stock Issued Under Stock and Benefit Plans	1,552	1,552	27,761		
Balance at September 30, 2004	82,990	$82,990	$506,560	$718,926(1)	$(54,775)

(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, 2004, $644.5 million of accumulated earnings was free of such limitations.

Common Stock

The Company has various plans which allow shareholders, employees and others to purchase shares of the Company common stock. The National Fuel Gas Company Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends and make cash investments in the Company's common stock and provides investors the opportunity to acquire shares of the Company common stock without the payment of any brokerage commissions in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in the Company common stock, in addition to a variety of other investment alternatives. Generally, 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 the 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, 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, 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
Granted in 2004	87,000	$24.95
Exercised in 2004(1)	(1,571,794)	$18.29
Forfeited in 2004	(84,105)	$25.40
Outstanding at September 30, 2004	12,496,439	$22.93
Option shares exercisable at September 30, 2004	11,594,368	$22.83
Option shares available for future grant at September 30, 2004(3)	919,537	

(1) In connection with exercising these options, 557,410, 200,708 and 43,834 shares were surrendered and canceled during 2004, 2003 and 2002, 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, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number Outstanding at 9/30/04	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 9/30/04	Weighted Average Exercise Price
$13.90-$16.68	441,060	1.0	$14.23	441,060	$14.23
$16.69-$19.46	1,139,558	2.0	$18.38	1,139,558	$18.38
$19.47-$22.24	2,545,696	5.0	$21.26	2,432,296	$21.25
$22.25-$25.02	6,073,297	5.3	$23.34	5,354,957	$23.19
$25.03-$27.80	2,296,828	6.3	$27.63	2,226,497	$27.68

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		
	2004	2003	2002
Shares of Restricted Stock Awarded	—	—	100,000
Weighted Average Market Price of Stock on Award Date	—	—	$ 24.50

As of September 30, 2004, 98,528 shares of non-vested restricted stock were outstanding. Vesting restrictions will lapse as follows: 2005 — 33,600 shares; 2006 — 34,600 shares; 2007 — 29,000 shares; and 2010 — 1,328 shares.

Compensation expense related to restricted stock under the Company's stock plans was $0.7 million, $1.0 million and $0.7 million for the years ended September 30, 2004, 2003 and 2002, respectively.

Redeemable Preferred Stock

As of September 30, 2004, 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	
	2004	2003
	(Thousands)	
Debentures(1):		
7¾% due February 2004	$ —	$ 125,000
Medium-Term Notes(1):		
6.0% to 7.50% due August 2004 to June 2025	749,000	849,000
Notes(1):		
5.25% to 6.50% due March 2013 to September 2022(2)	347,272	347,400
	1,096,272	1,321,400
Other Notes:		
Secured(3)	41,433	50,767
Unsecured	9,872	17,343
Total Long-Term Debt	1,147,577	1,389,510
Less Current Portion	14,260	241,731
	$1,133,317	$1,147,779

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

(2) At September 30, 2004 and 2003, $97,272,000 and $97,400,000, respectively, of these notes were callable at par at any time after September 15, 2006. The change in the amount outstanding from year to year is

attributable to the estates of individual note holders exercising put options due to the 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, 2004, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $14.3 million in 2005, $14.3 million in 2006, $9.3 million in 2007, $209.3 million in 2008, $104.1 million in 2009 and $796.3 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 $400.0 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 syndicated committed credit facility totaling $220.0 million. Of that amount, $110.0 million is committed to the Company through September 25, 2005, and $110.0 million is committed to the Company through September 30, 2005.

At September 30, 2004, the Company had outstanding short-term notes payable to banks and commercial paper of $26.5 million and $130.3 million, respectively. All of this debt was domestic. At September 30, 2003, the Company had outstanding notes payable to banks and commercial paper of $55.2 million and $63.0 million, respectively.

The weighted average interest rate on notes payable to banks was 1.82% and 1.27% at September 30, 2004 and 2003, respectively. The weighted average interest rate on commercial paper was 1.85% and 1.18% at September 30, 2004 and 2003, 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 .625 from October 1, 2003 through September 30, 2004 and .60 from October 1, 2004 and thereafter. At September 30, 2004, the Company's debt to capitalization ratio (as calculated under the facility) was .51. The constraints specified in the committed credit facility would permit an additional $576.0 million in short-term and/or long-term debt to be outstanding before the Company's debt to capitalization ratio would exceed .60. 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, 2004, the Company would have been permitted to issue up to a maximum of $713.0 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 1974 indenture pursuant to which $399.0 million (or 35%) of the Company's long-term debt (as of September 30, 2004) 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 under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $220.0 million, committed 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 any of its significant subsidiaries fails 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 any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2004, 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			
	2004 Carrying Amount	2004 Fair Value	2003 Carrying Amount	2003 Fair Value
	(Thousands)			
Long-Term Debt	$1,147,577	$1,199,189	$1,389,510	$1,520,606

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 $56.1 million and $53.5 million at September 30, 2004 and 2003, respectively. The fair value of the equity mutual fund was $7.8 million and $4.8 million at September 30, 2004 and 2003, respectively. The gross unrealized gain on the equity mutual fund was $0.1 million at September 30, 2004, as compared with a gross unrealized loss of $0.6 million at September 30, 2003. The fair value of the stock of an insurance company was $8.7 million and $5.7 million at September 30, 2004 and 2003, respectively. The gross unrealized gain on this stock was $6.2 million and $3.2 million at September 30, 2004 and 2003, respectively. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

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

Under the price swap agreements, the Company receives monthly payments from (or makes payments to) other parties based upon the difference between a fixed price and a variable price as specified by the agreement. The variable price is either a crude oil price quoted on the New York Mercantile Exchange (NYMEX) or a quoted natural gas price in "Inside FERC." 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. The Energy Marketing segment also uses these derivative financial instruments to hedge against rising prices, a risk to which they are exposed on their fixed price sales commitments. At September 30, 2004, the Company had natural gas price swap agreements covering a notional amount of 23.0 Bcf extending through 2009 at a weighted average fixed rate of $5.47 per Mcf. Of this amount, 3.3 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $5.51 per Mcf. The remaining 19.7 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $5.47 per Mcf. The Company also had crude oil price swap agreements covering a notional amount of 5,038,000 bbls extending through 2007 at a weighted average fixed rate of $32.01 per bbl. At September 30, 2004, the Company would have had to pay a net $82.2 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, 2004, the Company had no cost collars on natural gas covering a notional amount of 5.5 Bcf extending through 2006 with a weighted average floor price of $4.93 per Mcf and a weighted average ceiling price of $8.28 per Mcf. The Company also had no cost collars on crude oil covering a notional amount of 105,000 bbls extending through 2005 with a weighted average floor price of $25.00 per bbl and a weighted average ceiling price of $28.56 per bbl. At September 30, 2004, the Company would have had to pay $3.7 million to terminate the no cost collars.

At September 30, 2004, the Company, in the Exploration and Production segment, had purchased natural gas put options and sold natural gas call options extending through 2006. The call options sold by the Company cover a notional amount of 1.1 Bcf at a weighted average strike price of $8.06 per Mcf. The put options purchased by the Company cover a notional amount of 1.1 Bcf at a weighted average strike price of $5.99 per Mcf. These derivative financial instruments are accounted for as cash flow hedges. The call options are used to establish a ceiling price (the Company makes payments to the counterparty when a variable price rises above the ceiling price) for the anticipated sale of natural gas in the Exploration and Production segment. At September 30, 2004, the Company would have had to pay $1.0 million to terminate these call options. The put options are used to establish a floor price (the Company receives payment from the counterparty when a variable price falls below the floor price) for the anticipated sale of natural gas in the Exploration and Production segment. At September 30, 2004, the Company would have received $0.2 million to terminate these put options.

At September 30, 2004, the Company had long (purchased) futures contracts covering 3.5 Bcf of gas extending through 2007 at a weighted average contract price of $6.13 per Mcf. Of this amount, 3.1 Bcf is 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 remaining 0.4 Bcf is accounted for as cash flow hedges. The Company would have received $5.1 million to terminate these futures contracts at September 30, 2004.

At September 30, 2004, the Company had short (sold) futures contracts covering 7.3 Bcf of gas extending through 2006 at a weighted average contract price of $6.19 per Mcf. Of this amount, 5.9 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 1.4 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 had to pay $11.3 million to terminate these futures contracts at September 30, 2004.

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, 2004, the Company used seven counterparties for its over the counter derivative financial instruments. At September 30, 2004, no individual counterparty represented greater than 20% 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 limit 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, 2004 the notional amount on the collar was $44.3 million. The Company would have had to pay $2.2 million to terminate the interest rate collar at September 30, 2004.

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.

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

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2004	2003	2002	2004	2003	2002
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 694,960	$ 625,470	$ 580,046	$ 467,418	$ 393,851	$ 304,548
Service Cost	14,598	13,043	11,639	6,027	5,844	4,658
Interest Cost	40,565	40,967	40,720	26,393	26,124	21,617
Plan Participants' Contributions	—	—	—	627	682	610
Amendments	—	—	420	—	—	—
Actuarial (Gain) Loss	(19,593)	51,302	28,880	(62,146)	57,983	76,972
Benefits Paid	(36,998)	(35,822)	(36,235)	(16,316)	(17,066)	(14,554)
Benefit Obligation at End of Period	$ 693,532	$ 694,960	$ 625,470	$ 422,003	$ 467,418	$ 393,851
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 491,333	$ 485,927	$ 536,625	$ 166,494	$ 150,293	$ 161,959
Actual Return on Plan Assets	81,946	6,145	(29,898)	38,960	390	(18,181)
Employer Contribution	37,085	35,083	15,435	39,720	32,195	20,459
Plan Participants' Contributions	—	—	—	627	682	610
Benefits Paid	(36,998)	(35,822)	(36,235)	(16,316)	(17,066)	(14,554)
Fair Value of Assets at End of Period	$ 573,366	$ 491,333	$ 485,927	$ 229,485	$ 166,494	$ 150,293
Reconciliation of Funded Status						
Funded Status	$(120,166)	$(203,627)	$(139,543)	$(192,518)	$(300,924)	$(243,558)
Unrecognized Net Actuarial Loss	159,554	222,250	132,064	108,943	212,242	157,247
Unrecognized Transition (Asset) Obligation	—	—	(3,716)	64,144	71,272	78,399
Unrecognized Prior Service Cost	9,171	10,274	11,451	20	26	30
Net Amount Recognized at End of Period	$ 48,559	$ 28,897	$ 256	$ (19,411)	$ (17,384)	$ (7,882)
Amounts Recognized in the Balance Sheets Consist of:						
Accrued Benefit Liability	$ (91,587)	$(153,240)	$ (75,116)	$ (27,263)*	$ (23,163)*	$ (20,375)*
Prepaid Benefit Cost	14,536	10,782	10,944	7,852	5,779	12,493
Regulatory Assets	33,904	21,934	—	—	—	—
Intangible Assets	9,171	10,274	11,451	—	—	—
Accumulated Other Comprehensive Loss (Pre-Tax)	82,535	139,147	52,977	—	—	—
Net Amount Recognized at End of Period	$ 48,559	$ 28,897	$ 256	$ (19,411)	$ (17,384)	$ (7,882)
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	6.25%	6.00%	6.75%	6.25%**	6.00%	6.75%
Expected Return on Plan Assets	8.25%	8.25%	8.50%	8.25%	8.25%	8.50%
Rate of Compensation Increase	6.11%	6.11%	6.11%	6.11%	6.11%	6.11%

* Amounts are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets.

** The weighted average discount rate was 6.0% through 12/8/2003. Subsequent to 12/8/2003, the discount rate used was 6.25%.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2004	2003	2002	2004	2003	2002
	(Thousands)					
Components of Net Periodic Benefit Cost						
Service Cost	$ 14,598	$ 13,043	$ 11,639	$ 6,027	$ 5,844	$ 4,658
Interest Cost	40,565	40,967	40,720	26,393	26,124	21,617
Expected Return on Plan Assets	(48,281)	(47,260)	(48,454)	(14,898)	(12,268)	(13,551)
Amortization of Prior Service Cost	1,103	1,176	1,205	4	4	4
Amortization of Transition Amount	—	(3,716)	(3,716)	7,127	7,127	7,127
Recognition of Actuarial (Gain) or Loss	9,438	2,231	(1,061)	17,092	14,866	4,289
Net Amortization and Deferral for Regulatory Purposes	722	3,781	7,379	(9,731)	(15,423)	(729)
Net Periodic Benefit Cost	$ 18,145	$ 10,222	$ 7,712	$ 32,014	$ 26,274	$ 23,415
Other Comprehensive (Income) Loss (Pre-Tax) Attributable to Change in Additional Minimum Liability Recognition	$(56,612)	$ 86,170	$ 52,977	$ —	$ —	$ —
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Discount Rate	6.00%	6.75%	7.25%	6.25%*	6.75%	7.25%
Expected Return on Plan Assets	8.25%	8.50%	8.50%	8.25%	8.50%	8.50%
Rate of Compensation Increase	6.11%	6.11%	6.11%	6.11%	6.11%	6.11%

* The weighted average discount rate was 6.0% through 12/8/2003. Subsequent to 12/8/2003, the discount rate used was 6.25%.

In accordance with the provisions of SFAS No. 87, "Employers' Accounting for Pensions," the Company recorded an additional minimum liability at September 30, 2004, 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 projected benefit obligation, accumulated benefit obligation and fair value of assets for the retirement plan were as follows:

	2004	2003	2002
Projected Benefit Obligation	$693,532	$694,960	$625,470
Accumulated Benefit Obligation	$616,513	$611,858	$550,099
Fair Value of Plan Assets	$573,366	$491,333	$485,927

The effect of the discount rate change for the Retirement Plan in 2004, was to decrease the benefit obligation by $20.2 million. The effects of the discount rate changes in 2003 and 2002 were to increase the Benefit Obligation of the Retirement Plan by $57.4 million and $34.0 million as of the end of each period, respectively.

The Company made cash contributions totaling $37.1 million to the Retirement Plan during the year ended September 30, 2004. The Company expects that the annual contribution to the Retirement Plan in 2005 will be in the range of $25.0 million to $35.0 million. The following benefit payments, which reflect expected future service, are expected to be paid during the next five years and the five years thereafter:

$40.5 million in 2005; $42.3 million in 2006; $44.3 million in 2007; $46.2 million in 2008; $48.6 million in 2009; and $279.3 million in the five years thereafter.

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 $13.7 million, $5.1 million and $8.5 million in 2004, 2003 and 2002, respectively. The accumulated benefit obligation for this plan was $18.2 million and $40.0 million at September 30, 2004 and 2003, respectively. The projected benefit obligation for the plan was $35.7 million and $48.3 million at September 30, 2004 and 2003, respectively. The actuarial valuations for this plan were determined based on a discount rate of 6.25%, 6.0% and 6.75% as of September 30, 2004, 2003 and 2002 respectively; a weighted rate of compensation increase of 10.0% as of September 30, 2004, and 8.11% as of September 30, 2003 and 2002; and an expected long-term rate of return on plan assets of 8.25%, at September 30, 2004 and 2003, and 8.5% at September 30, 2002. In January 2004, a participant of the plan received a $23.0 million lump sum payment under a provision of an agreement previously entered into between the Company and the participant. Under GAAP, this payment was considered a partial settlement of the projected benefit obligation of the plan. Accordingly, GAAP required that a pro rata portion of this plan's unrecognized actuarial losses resulting from experience different from that assumed and from changes in assumptions be currently recognized. Therefore, $9.9 million before tax ($6.4 million, after tax) was recognized as a settlement expense (included in Operation and Maintenance Expense) on the income statement.

On December 8, 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. This Act introduces a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In accordance with FASB Staff Position FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", since the Company is assumed to continue to provide a prescription drug benefit to retirees in the point of service and indemnity plans that is at least actuarially equivalent to Medicare Part D, the impact of the Act was reflected as of December 8, 2003. The discount rate was changed from 6.0% to 6.25% per annum as of the remeasurement date, which resulted in a decrease in the benefit obligation of $15.9 million. The accumulated post-retirement benefit obligation decreased by $42.9 million and the Net Periodic Post-Retirement Benefit Cost decreased by $4.2 million as a result of the Act. The effect of the subsidy by Net Periodic Post-Retirement Benefit Cost component is shown below and is reflected within Components of Net Periodic Benefit Cost shown in the table above.

	Effect of Subsidy
Service Cost	$ (286,527)
Interest Cost	(1,500,001)
Net Amortization and Deferral of Actuarial (Gain) Loss	(2,372,270)
Net Periodic Post-Retirement Benefit Cost	$(4,158,798)

The estimated gross amount of subsidy receipts is as follows:

First Year	$ —
Second Year	$ (649,599)
Third Year	$ (1,475,809)
Fourth Year	$ (1,672,331)
Fifth Year	$ (1,861,515)
Next Five Years	$(11,935,959)

Effective July 1, 2004, the Medicare Part B Reimbursement trend assumption was changed. The effect of this change was to decrease the Accumulated Post-Retirement Benefit Obligation by $3.5 million for 2004.

The effects of the discount rate changes in 2003 and 2002 were to increase the Other Post-Retirement Benefit Obligation by $45.1 million and $21.7 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 Post-Retirement Benefit Obligation by $22.6 million. Other actuarial experience increased the Accumulated Post-Retirement 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 Post-Retirement 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 12.0% for 2002, 11.0% for 2003, 10.0% for 2004 and gradually decline to 5.5% by the year 2010 and remain level thereafter. The annual rate of increase for medical care benefits provided by healthcare maintenance organizations was assumed to be 12.0% in 2002, 11.0% in 2003, 10.0% in 2004 and gradually decline to 5.5% by the year 2010 and remain level thereafter. The annual rate of increase in the per capita cost of covered prescription drug benefits was assumed to be 15.0% for 2002, 13.5% for 2003 and 12.0% for 2004, and gradually decline to 5.5% by the year 2010 and remain level thereafter. The annual rate of increase in the per capita Medicare Part B Reimbursement was assumed to be 8.0% for 2002, 7.0% for 2003, 9.25% for 2004 and gradually decline to 5.0% by the year 2013 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, 2004 would be increased by $57.4 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 2004 by $5.8 million. If the health care cost trend rates were decreased by 1% in each year, the Benefit Obligation as of October 1, 2004 would be decreased by $47.4 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 2004 by $4.7 million.

The Company made cash contributions totaling $39.7 million to the Other Post-Retirement Benefit Plan during the year ended September 30, 2004. The Company expects that the annual contribution to the Other Post-Retirement Benefit Plan in 2005 will be in the range of $30.0 million to $40.0 million.

The Company's retirement plan weighted average asset allocations at September 30, 2004, 2003 and 2002 by asset category are as follows:

		Percentage of Plan Assets at September 30		
Asset Category	Target Allocation 2005	2004	2003	2002
Equity Securities	60-65%	61%	53%	55%
Fixed Income Securities	25-30%	28%	32%	29%
Other	10-15%	11%	15%	16%
Total		100%	100%	100%

The Company's post-retirement plan weighted average asset allocations at September 30, 2004, 2003 and 2002 by asset category are as follows:

Asset Category	Target Allocation 2005	Percentage of Plan Assets at September 30 2004	2003	2002
Equity Securities	93%	91%	85%	90%
Fixed Income Securities	3%	1%	1%	0%
Other	4%	8%	14%	10%
Total		100%	100%	100%

The Company's assumption regarding the expected long-term rate of return on plan assets is 8.25%. The return assumption reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets.

The long-term investment objective of the pension trust is to achieve the target total return in accordance with the Company's risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition.

Investment managers are retained to manage separate pools of assets. Comparative market and peer group performance of individual managers and the total fund are monitored on a regular basis, and reviewed by the Company's Retirement Committee on at least a quarterly basis.

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 $14.0 million. This liability has been recorded on the Consolidated Balance Sheet at September 30, 2004. 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 88% 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 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 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 (see 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 $33\frac{1}{3}$% 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, Louisiana and Alabama 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 for the year ended September 30, 2003. Proved reserves associated with the properties sold were 19.4 million barrels of oil and 0.3 Bcf of natural gas. When the transaction closed, the initial proceeds received were subject to an adjustment based on working capital and the resolution of certain income tax matters. In 2004, those items were resolved with the buyer and, as a result, the Company received an additional $4.6 million of sales proceeds.

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 for the year ended September 30, 2003. During 2004, the Company received final timber cruise information of the properties it sold and, based on that information, determined that property records pertaining to $1.3 million of timber property were not properly shown as having been transferred to the purchaser. As a result, the Company removed those assets from its property records and adjusted the previously recognized gain downward by recognizing a pretax loss of $1.3 million.

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, 2004									
	Utility	Pipeline and Storage	Exploration and Production	International	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)									
Revenue from External Customers	$1,137,288	$122,970	$ 293,698	$123,425	$284,349	$ 55,968	$2,017,698	$13,695	$ —	$2,031,393
Intersegment Revenues	$ 15,353	$ 86,737	$ —	$ —	$ —	$ 2	$ 102,092	$ —	$(102,092)	$ —
Interest Expense	$ 21,945	$ 10,933	$ 50,642	$ 7,080	$ 33	$ 2,218	$ 92,851	$ 919	$ (3,180)	$ 90,590
Depreciation, Depletion and Amortization	$ 39,101	$ 37,345	$ 89,943	$ 15,257	$ 102	$ 6,277	$ 188,025	$ 1,071	$ 442	$ 189,538
Income Tax Expense	$ 31,393	$ 30,968	$ 28,899	$ (6,137)	$ 3,964	$ 3,320	$ 92,407	$ 829	$ (499)	$ 92,737
Significant Item:										
Loss on Sale of Timber Properties	$ —	$ —	$ —	$ —	$ —	$ 1,252	$ 1,252	$ —	$ —	$ 1,252
Significant Item:										
Gain on Sale of Oil and Gas Producing Properties	$ —	$ —	$ 4,645	$ —	$ —	$ —	$ 4,645	$ —	$ —	$ 4,645
Segment Profit (Loss):										
Net Income	$ 46,718	$ 47,726	$ 54,344	$ 5,982	$ 5,535	$ 5,637	$ 165,942	$ 1,530	$ (886)	$ 166,586
Expenditures for Additions to Long-Lived Assets	$ 55,449	$ 23,196	$ 77,654	$ 7,498	$ 10	$ 2,823	$ 166,630	$ 200	$ 5,511	$ 172,341
	At September 30, 2004									
	(Thousands)									
Segment Assets	$1,390,361	$777,800	$1,039,524	$268,119	$ 65,971	$143,101	$3,684,876	$73,583	$ (46,661)	$3,711,798

	Utility	Pipeline and Storage	Exploration and Production	International	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	Year Ended September 30, 2003 (Thousands)									
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	$ 168,787	$ —	$ —	$ 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	$1,411,808	$812,846	$969,512	$247,721	$ 54,134	$125,915	$3,621,936	$77,195	$ 19,929	$3,719,060

(1) Amount includes the acquisition of all of the partnership interests in Toro Partners, L.P. and is disclosed in Note J — Acquisitions.

	Year Ended September 30, 2002									
	Utility	Pipeline and Storage	Exploration and Production	International	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)									
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

Geographic Information	For the Year Ended September 30 2004	2003	2002
		(Thousands)	
Revenues from External Customers(1):			
United States	$1,867,335	$1,818,980	$1,293,239
Czech Republic	123,425	114,070	95,315
Canada	40,633	102,421	75,942
	$2,031,393	$2,035,471	$1,464,496
		At September 30 (Thousands)	
Long-Lived Assets:			
United States	$2,967,277	$2,975,329	$2,621,001
Czech Republic	228,179	219,695	216,044
Canada	143,042	116,655	258,196
	$3,338,498	$3,311,679	$3,095,241

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

Note I — 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, 2004 and 2003 is as follows:

	At September 30 2004	2003
	(Thousands)	
ESNE	$10,045	$11,113
Seneca Energy	5,169	4,445
Model City	1,230	867
	$16,444	$16,425

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, which owns and operates 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

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 8 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, 2004			At September 30, 2003
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Net Carrying Amount
Intangible Assets Subject to Amortization				
Long-Term Transportation Contracts	$ 8,580	$(1,782)	$ 6,798	$ 7,867
Long-Term Gas Purchase Contracts	31,864	(1,839)	30,025	31,522
Intangible Assets Not Subject to Amortization				
Retirement Plan Intangible Asset (see Note F)	9,171	—	9,171	10,275
	$49,615	$(3,621)	$45,994	$49,664
Aggregate Amortization Expense				
For the Year Ended September 30, 2004	$ 2,567			
For the Year Ended September 30, 2003	$ 1,054			

Amortization expense for the transportation contracts is estimated to be $1.1 million annually for 2005, 2006, 2007 and 2008. Amortization is estimated to be $0.5 million for 2009. Amortization expense for the gas purchase contracts is estimated to be $1.6 million annually for 2005, 2006, 2007, 2008 and 2009.

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 Per Common Share Basic	Earnings Per Common Share Diluted
2004	(Thousands, except per common share amounts)				
9/30/2004	$278,197	$ 27,675	$ 7,754	$0.09	$0.09
6/30/2004	$419,006	$ 72,324	$32,563(1)	$0.40	$0.39
3/31/2004	$801,677	$148,554	$77,055(2)	$0.94	$0.93
12/31/2003	$532,513	$ 95,817	$49,214(3)	$0.60	$0.60
2003					
9/30/2003	$297,170	$122,674	$58,146(4)	$0.71	$0.71
6/30/2003	$449,530	$ 35,411	$ 2,219(5)	$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(6)	$0.47	$0.47

(1) Includes expense of $0.8 million related to an adjustment to the gain on sale of timber properties recognized in 2003.

(2) Includes expense of $6.4 million due to the recognition of a pension settlement loss and income of $4.6 million due to an adjustment to the loss on sale of oil and gas properties recognized in 2003.

(3) Includes income of $5.2 million related to tax rate changes in the Czech Republic.

(4) Includes expense of $6.3 million related to the impairment of oil and gas producing properties, loss of $39.6 million related to the sale of oil and gas producing properties, and a gain of $102.2 million from the sale of timber properties.

(5) Includes expense of $22.6 million related to the impairment of oil and gas producing properties.

(6) 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).

Note M — Market for Common Stock and Related Shareholder Matters (unaudited)

At September 30, 2004, there were 19,063 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, 2004 and 2003, are shown below:

Quarter Ended	Price Range High	Price Range Low	Dividends Declared
2004			
9/30/2004	$28.43	$24.84	$.280
6/30/2004	$25.57	$23.75	$.280
3/31/2004	$26.48	$24.26	$.270
12/31/2003	$25.01	$21.71	$.270
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

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 2004	At September 30 2003
	(Thousands)	
Proved Properties(1)	$1,489,284	$1,647,075
Unproved Properties	27,277	30,955
	1,516,561	1,678,030
Less — Accumulated Depreciation, Depletion and Amortization	609,469	763,258
	$ 907,092	$ 914,772

(1) Includes asset retirement costs of $22.2 million and $18.1 million at September 30, 2004 and 2003, respectively.

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, 2004:

	Total as of September 30, 2004	Year Costs Incurred 2004	2003	2002	Prior
		(Thousands)			
Acquisition Costs	$27,277	$7,650	$6,748	$2,884	$9,995

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

	Year Ended September 30		
	2004	2003	2002
		(Thousands)	
United States			
Property Acquisition Costs:			
Proved	$ (8)	$ (13)	$ 9,316
Unproved	3,529	1,920	698
Exploration Costs	10,503	17,947	25,583
Development Costs	31,881	23,649	51,792
Asset Retirement Costs	2,292	242	—
	48,197	43,745	87,389
Canada			
Property Acquisition Costs:			
Proved	29	181	(536)
Unproved	3,167	6,217	2,804
Exploration Costs	22,624	6,641	8,779
Development Costs	5,500	17,745	15,332
Asset Retirement Costs	1,218	—	—
	32,538	30,784	26,379
Total			
Property Acquisition Costs:(1)			
Proved	21	168	8,780
Unproved	6,696	8,137	3,502
Exploration Costs	33,127	24,588	34,362
Development Costs	37,381	41,394	67,124
Asset Retirement Costs	3,510	242	—
	$80,735	$74,529	$113,768

For the years ended September 30, 2004, 2003 and 2002, the Company spent $12.1 million, $1.7 million and $18.2 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30,		
	2004	2003	2002
	(Thousands, except per Mcfe amounts)		
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $72, $69 and $43, respectively)	$151,570	$148,104	$104,954
Oil, Condensate and Other Liquids	139,301	118,277	101,549
Total Operating Revenues(1)	290,871	266,381	206,503
Production/Lifting Costs	39,677	39,162	42,956
Accretion Expense	1,756	1,800	—
Depreciation, Depletion and Amortization ($1.41, $1.29 and $1.25 per Mcfe of production)	73,396	70,127	80,142
Income Tax Expense	65,337	62,672	30,253
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	110,705	92,620	53,152
Canada			
Operating Revenues:			
Natural Gas	30,359	26,992	14,621
Oil, Condensate and Other Liquids	10,018	62,908	56,511
Total Operating Revenues(1)	40,377	89,900	71,132
Production/Lifting Costs	8,176	33,038	30,109
Accretion Expense	177	802	—
Depreciation, Depletion and Amortization ($1.83, $1.30 and $0.93 per Mcfe of production)	14,922	26,165	21,707
Impairment of Oil and Gas Producing Properties(2)	—	42,774	—
Income Tax Expense (Benefit)	5,235	(3,273)	4,672
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	11,867	(9,606)	14,644

	Year Ended September 30,		
	2004	2003	2002
	(Thousands, except per Mcfe amounts)		
Total			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $72, $69 and $43, respectively)	181,929	175,096	119,575
Oil, Condensate and Other Liquids	149,319	181,185	158,060
Total Operating Revenues(1)	331,248	356,281	277,635
Production/Lifting Costs	47,853	72,200	73,065
Accretion Expense	1,933	2,602	—
Depreciation, Depletion and Amortization ($1.47, $1.30 and $1.16 per Mcfe of production)	88,318	96,292	101,849
Impairment of Oil and Gas Producing Properties(2)	—	42,774	—
Income Tax Expense	70,572	59,399	34,925
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$122,572	$ 83,014	$ 67,796

(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, 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)
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)

	Gas MMcf					
	U.S.					
	Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada	Total Company
September 30, 2003	47,683	70,062	81,219	198,964	52,153	251,117
Extensions and Discoveries	2,632	—	3,784	6,416	15,925	22,341
Revisions of Previous Estimates	(4,984)	1,831	(1,111)	(4,264)	(11,004)	(15,268)
Production	(17,596)	(4,057)	(5,132)	(26,785)	(6,228)	(33,013)
Sales of Minerals in Place	(1)	(392)	—	(393)	—	(393)
September 30, 2004	27,734	67,444	78,760	173,938	50,846	224,784
Proved Developed Reserves:						
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
September 30, 2004	25,827	53,035	78,760	157,622	46,223	203,845

	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, 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)
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)
September 30, 2003	3,383	63,852	138	67,373	2,391	69,764
Extensions and Discoveries	19	—	18	37	181	218
Revisions of Previous Estimates	213	(17)	11	207	(144)	63
Production	(1,534)	(2,650)	(20)	(4,204)	(324)	(4,528)
Sales of Minerals in Place	(1)	(303)	—	(304)	—	(304)
September 30, 2004	2,080	60,882	147	63,109	2,104	65,213
Proved Developed Reserves:						
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
September 30, 2004	2,061	38,631	148	40,840	2,104	42,944

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,		
	2004	2003	2002
		(Thousands)	
United States			
Future Cash Inflows	$3,728,168	$2,684,286	$2,764,556
Less:			
Future Production Costs	676,361	579,321	546,182
Future Development Costs	124,298	116,639	117,999
Future Income Tax Expense at Applicable Statutory Rate	995,327	613,893	653,347
Future Net Cash Flows	1,932,182	1,374,433	1,447,028
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	996,813	641,185	665,941
Standardized Measure of Discounted Future Net Cash Flows	935,369	733,248	781,087

	Year Ended September 30,		
	2004	2003	2002
		(Thousands)	
Canada			
Future Cash Inflows	343,026	279,772	888,515
Less:			
Future Production Costs	111,519	85,817	413,006
Future Development Costs	13,222	9,787	25,398
Future Income Tax Expense at Applicable Statutory Rate	60,610	58,436	101,919
Future Net Cash Flows	157,675	125,732	348,192
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	46,945	40,575	103,097
Standardized Measure of Discounted Future Net Cash Flows	110,730	85,157	245,095
Total			
Future Cash Inflows	4,071,194	2,964,058	3,653,071
Less:			
Future Production Costs	787,880	665,138	959,188
Future Development Costs	137,520	126,426	143,397
Future Income Tax Expense at Applicable Statutory Rate	1,055,937	672,329	755,266
Future Net Cash Flows	2,089,857	1,500,165	1,795,220
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,043,758	681,760	769,038
Standardized Measure of Discounted Future Net Cash Flows	$1,046,099	$ 818,405	$1,026,182

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

	Year Ended September 30,		
	2004	2003	2002
		(Thousands)	
United States			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	$ 733,248	$ 781,087	$ 605,350
Sales, Net of Production Costs	(251,194)	(227,219)	(163,548)
Net Changes in Prices, Net of Production Costs	592,326	11,130	441,085
Purchases of Minerals in Place	—	—	—
Sales of Minerals in Place	(5,554)	—	(27,197)
Extensions and Discoveries	16,638	29,266	42,970
Changes in Estimated Future Development Costs	(40,042)	(35,062)	(42,069)
Previously Estimated Development Costs Incurred	32,653	36,423	45,310
Net Change in Income Taxes at Applicable Statutory Rate	(166,055)	24,796	(126,263)
Revisions of Previous Quantity Estimates	(5,107)	(3,572)	(32,646)
Accretion of Discount and Other	28,456	116,399	38,095
Standardized Measure of Discounted Future Net Cash Flows at End of Year	935,369	733,248	781,087
Canada			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	85,157	245,095	181,439
Sales, Net of Production Costs	(32,201)	(56,862)	(41,023)
Net Changes in Prices, Net of Production Costs	29,230	8,167	111,148
Purchases of Minerals in Place	—	—	—
Sales of Minerals in Place	—	(120,960)	(3,084)
Extensions and Discoveries	36,986	28,241	29,813
Changes in Estimated Future Development Costs	(8,491)	(14,045)	18,151
Previously Estimated Development Costs Incurred	5,055	29,657	12,361
Net Change in Income Taxes at Applicable Statutory Rate	(2,640)	(6,280)	(6,910)
Revisions of Previous Quantity Estimates	(19,369)	(41,205)	(88,571)
Accretion of Discount and Other	17,003	13,349	31,771
Standardized Measure of Discounted Future Net Cash Flows at End of Year	110,730	85,157	245,095

	Year Ended September 30, 2004	2003	2002
		(Thousands)	
Total			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	818,405	1,026,182	786,789
Sales, Net of Production Costs	(283,395)	(284,081)	(204,571)
Net Changes in Prices, Net of Production Costs	621,556	19,297	552,233
Purchases of Minerals in Place	—	—	—
Sales of Minerals in Place	(5,554)	(120,960)	(30,281)
Extensions and Discoveries	53,624	57,507	72,783
Changes in Estimated Future Development Costs	(48,533)	(49,107)	(23,918)
Previously Estimated Development Costs Incurred	37,708	66,080	57,671
Net Change in Income Taxes at Applicable Statutory Rate	(168,695)	18,516	(133,173)
Revisions of Previous Quantity Estimates	(24,476)	(44,777)	(121,217)
Accretion of Discount and Other	45,459	129,748	69,866
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$1,046,099	$ 818,405	$1,026,182

Schedule II — Valuation and Qualifying Accounts

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
			(Thousands)		
Year Ended September 30, 2004					
Reserve for Doubtful Accounts	$17,943	$20,328	$ —	$20,831	$17,440
Deferred Tax Valuation Allowance	$ 6,357	$ (3,480)	$ —	$ —	$ 2,877
Year Ended September 30, 2003					
Reserve for Doubtful Accounts	$17,299	$17,275	$ —	$16,631	$17,943
Deferred Tax Valuation Allowance	$ —	$ 6,357	$ —	$ —	$ 6,357
Year Ended September 30, 2002					
Reserve for Doubtful Accounts	$18,521	$16,082	$2,834	$20,138	$17,299

(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.

Item 9B ***Other Information***

None

PART III

Item 10 ***Directors and Executive Officers of the Registrant***

The information required by this item concerning the directors of the Company is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 17, 2005 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2004. 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 in 2008," "Directors Whose Terms Expire in 2007," "Directors Whose Terms Expire in 2006," 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 has posted such Code of Business Conduct and Ethics on the Company's website, *www.nationalfuelgas.com*, together with certain other corporate governance documents. 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 Investor 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 17, 2005 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2004. 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

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 17, 2005 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2004. The equity compensation plan information is set forth in the definitive Proxy Statement under the caption "Equity Compensation Plan Information" and is incorporated herein by reference.

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 17, 2005 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2004. 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 17, 2005 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2004. 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 17, 2005 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2004. 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 17, 2005 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2004. The information concerning principal accountant fees and services is set forth in the definitive Proxy Statement under the caption "Audit Fees" and is incorporated herein by reference.

PART IV

Item 15 *Exhibits and Financial Statement Schedules*

(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 9, 2004 (Exhibit 3(ii), Form 8-K dated December 9, 2004 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)

Exhibit Number	Description of Exhibits
•	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)
•	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)
•	First Amendment to Credit Agreement, among the Company, the Lenders and JPMorgan Chase Bank, dated September 29, 2003 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2003 in File No. 1-3880)
•	Second Amendment to Credit Agreement, among the Company, the Lenders and JPMorgan Chase Bank, dated September 26, 2004 (Exhibit 99, Form 8-K dated September 30, 2004 in File No. 1-3880)
(iii)	Compensatory plans for officers:
•	Retirement Benefit Agreement, dated September 22, 2003, between the Company and David F. Smith (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2003 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, Joseph P. Pawlowski, James D. Ramsdell, Dennis J. Seeley, David F. Smith and Ronald J. Tanski (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880)

Exhibit Number	Description of Exhibits

- 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 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)
- 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

Exhibit Number	Description of Exhibits
•	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)
•	Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and Dennis J. Seeley (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Dennis J. Seeley, dated March 29, 1999 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Split Dollar Insurance and Death Benefit Agreement dated September 15, 1997, between the Company and Bruce H. Hale (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and Bruce H. Hale, dated March 29, 1999 (Exhibit 10.12, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
10.1	National Fuel Gas Company Parameters for Executive Life Insurance Plan
•	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)
10.2	National Fuel Gas Company Participating Subsidiaries Executive Retirement Plan 2003 Trust Agreement (I), dated September 1, 2003
•	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)

Exhibit Number	Description of Exhibits
•	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 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)
•	Amendment No. 1 to Retirement Supplement Agreement, dated March 11, 2004, between the Company and Joseph P. Pawlowski (Exhibit 10(iii), Form 10-Q for the quarterly period ended March 31, 2004 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)
10.3	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated, effective September 9, 2004
•	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)
10.4	Retirement and Consulting Agreement, dated September 5, 2001, between the Company and Bernard J. Kennedy
(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 13a-15(e)/15d-15(e) Certifications
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-15(e)/15d-15(e) of the Exchange Act.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-15(e)/15d-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 not 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.

Exhibit Number	Description of Exhibits

- 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.

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 9, 2004

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	Date
/s/ P. C. ACKERMAN P. C. Ackerman	Chairman of the Board, President, Chief Executive Officer and Director	December 9, 2004
/s/ R. T. BRADY R. T. Brady	Director	December 9, 2004
/s/ R. D. CASH R. D. Cash	Director	December 9, 2004
/s/ R. E. KIDDER R. E. Kidder	Director	December 9, 2004
/s/ B. S. LEE B. S. Lee	Director	December 9, 2004
/s/ G. L. MAZANEC G. L. Mazanec	Director	December 9, 2004
/s/ J. F. RIORDAN J. F. Riordan	Director	December 9, 2004
/s/ R. J. TANSKI R. J. Tanski	Treasurer and Principal Financial Officer	December 9, 2004
/s/ K. M. CAMIOLO K. M. Camiolo	Controller and Principal Accounting Officer	December 9, 2004

Glossary

Absorption Cooling A process that uses heat to produce chilled water for space cooling, dehumidification or process cooling. Heat which would otherwise be wasted from a power generation unit, such as a microturbine, may be used in this process.

Annuity Periodic payments made over a specified period of time.

Area of Mutual Interest A geographical area where the parties agree to share certain additional leases acquired by any of them in the future.

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.

Book Value The original cost of an asset minus depreciation. In corporate terms, book value equals the net asset value.

Brine Solution Water saturated with salt, frequently produced with oil.

Btu (British thermal unit) The amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit.

Capital Spending The amount of money a company spends to buy capital assets or upgrade its existing capital assets.

Capitalization The total of Shareholder Equity, Long-Term Debt and Short-Term Debt as recorded on the Balance Sheet.

Compression Mechanical equipment that increases the pressure of flowing natural gas for transportation.

Compressor Site With regard to production, a location which gathers, scrubs, cleans and dehydrates natural gas prior to compression.

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

Development Costs Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.

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

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.

Exploration Costs Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.

Exploratory Well A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.

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.

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

Glycol An organic compound used in the heat exchange process.

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

Grapple Skidder A rubber-tired four-wheeled-drive machine used in the logging industry that has a maneuverable device which picks up fallen trees and moves them to a location where the trees then can be loaded on trucks.

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

Heavy Oil A type of crude petroleum that usually is not economically recoverable in its natural state without being heated or diluted.

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, lending and borrowing of natural gas.

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

Liquefied Natural Gas (LNG) Natural gas that has been cooled to about -160 degrees Centigrade for storage or shipment as a liquid.

Liquid Market A market in which securities or commodities are easily bought and sold because of the willingness of interested buyers and sellers to trade large quantities at reasonable prices.

Mbbl Thousand barrels.

Mcf Thousand cubic feet.

MDth Thousand dekatherms.

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.

Net Pay The estimated volume of recoverable natural gas.

Non-Cash Write Down An expense recorded in the financial statements to reduce the value of an asset without actual cash being disbursed.

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.

Overriding Interest A fractional interest in the oil and gas produced, free of the expense of production, and in addition to the usual landowner's royalty reserved in an oil and gas lease.

PaPUC Pennsylvania Public Utility Commission.

Payout Generally, the recovery from production of costs of drilling and equipping a well.

Payout Ratio The percentage of a company's earnings that holders of common stock receive in cash dividends.

Precedent Agreement An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called "conditions precedent") happen, usually within a specified time.

Proved Developed Reserves Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Undeveloped Reserves Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.

Repatriate To return to the country of origin.

Reserves The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.

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 service from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.

Scrubbing The process of purifying or otherwise treating gas for the extraction or removal of hydrogen sulfide or other harmful substances.

Spot Gas Purchases The purchase of natural gas on a short-term basis.

Steaming A process of generating steam for use in a heavy oil reservoir to increase recovery of the oil.

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

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

Waste Gas Gas that could be recovered and put to use.

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 are assessed 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.

Working Interest An interest in a mineral property that entitles the owner of the interest to all or a share of mineral production from the property, usually subject to a royalty, and that permits the owner to explore, develop, and operate the property.

Principal Officers

National Fuel Gas Company

Philip C. Ackerman
Chairman of the Board,
President and
Chief Executive Officer
Ronald J. Tanski
Treasurer and
Principal Financial Officer
Karen M. Camiolo
Controller and
Principal Accounting Officer
Anna Marie Cellino
Secretary

Principal 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
Ronald J. Tanski
Senior Vice President
and Treasurer
James D. Ramsdell
Senior Vice President
Dennis J. Seeley
Senior Vice President
Karen M. Camiolo
Controller
Carl M. Carlotti
Vice President
Steven Wagner
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
Ronald J. Tanski
Treasurer and Secretary
Karen M. Camiolo
Controller

Seneca Resources Corporation

Philip C. Ackerman
Chairman of the Board
James A. Beck
President
Barry L. McMahan
Senior 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, 10]
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 [1,3,7]
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, Associated Electric & Gas Insurance Services Limited, and TODCO (The Offshore Drilling Company). Board member since February 2003.

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

Bernard S. Lee, PhD [2,9]
Former President of the Institute of Gas Technology. Board member since 1994. Director of 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 Dynegy Inc. since May 2004. 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.

Richard G. Reiten
Chairman of Northwest Natural Gas Company. Board member since December 2004. Director of BlueCross BlueShield of Oregon, The Regence Group and Associated Electric & Gas Insurance Services Limited.

John F. Riordan [5,7]
President and Chief Executive Officer of the Gas Technology Institute since April 2000. Board member since 2000. Director of Nicor Inc. and a Trustee of 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
[9] Member of Finance Committee
[10] Chairman, Finance Committee

Investor Information

Common Stock Transfer Agent and Registrar

The Bank of New York
101 Barclay Street
New York, NY 10286
Tel. (800) 648-8166
Web site at:
http://www.stockbny.com
E-mail: shareowners@bankofny.com

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 The Bank of New York, the agent for the Plan, at:

The Bank of New York*
Shareholder Relations
P.O. Box 11258
New York, NY 10286-1258
Tel. (800) 648-8166
E-mail: shareowners@bankofny.com

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

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 17, 2005, at The Woodlands Resort and Conference Center, 2301 North Millbend Drive, The Woodlands, TX 77380. Formal notice of the meeting, proxy statement and proxy will be mailed to shareholders of record as of the close of business on December 20, 2004.

Investor Relations

Investors or financial analysts desiring information should contact:

Ronald J. Tanski, *Treasurer*
Tel. (716) 857-6981

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

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

Additional Shareholder Reports

Additional copies of this report and the Financial and Statistical Supplement to the 2004 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

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

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

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

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