2009 Annual Report and Form 10-K

National Fuel Gas Company

driving growth, building value

National Fuel Gas
At a Glance

National Fuel continues to generate impressive shareholder returns from its balanced and integrated business model. Our value proposition has been significantly enhanced by an ambitious Appalachian drilling program, especially in the Marcellus Shale, and complementary expansion opportunities for the Pipeline & Storage segment. In 2010, we will capitalize on our many opportunities, driving growth and creating value for our Shareholders, and we look forward to continuing a solid record of performance that has distinguished National Fuel for more than 100 years.

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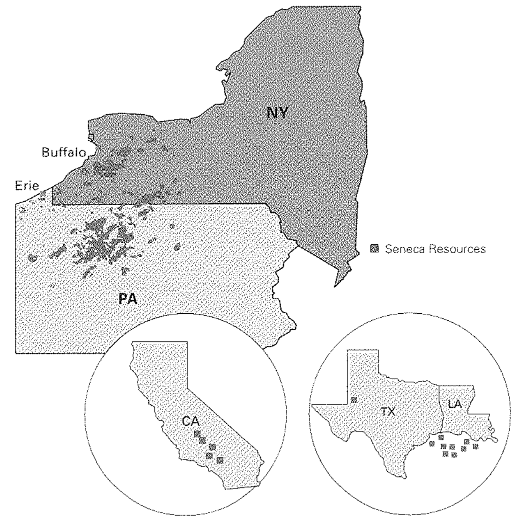
All references to years in this Annual Report are to the Company's fiscal year, which ends September 30, unless otherwise stated.



Exploration & Production

Seneca Resources Corporation explores for, develops and purchases natural gas and oil reserves in California, in Appalachia, and in the Gulf Coast region of Texas and Louisiana. Currently, Seneca's efforts are focused on evaluating, exploring and developing reserves in Appalachia, economically producing reserves in California, and exploiting opportunities in the shallow waters of the Gulf of Mexico.

2009 Highlights

Operating Revenues: $382.8 million[1]
Operating Income: $6.1 million[2]
Net Income: $(10.2) million
Capital Expenditures: $188.3 million
Total Assets: $1,265.7 million

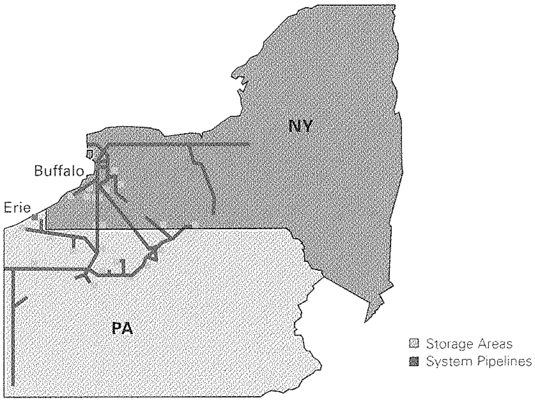
- Net loss of $10.2 million, but excluding a non-cash ceiling test impairment of $108.2 million, operating earnings were $98.0 million.
- Total Seneca reserve replacement ratio of 160 percent.
- Appalachia reserve replacement ratio of 341 percent, which included 21.2 billion cubic feet of Marcellus reserve additions.
- First two Seneca-operated Marcellus Shale horizontal wells flowed at a combined average rate of more than 10 million cubic feet of natural gas per day during a seven-day period. First year finding and development costs in the Marcellus of $1.28 per thousand cubic feet of natural gas, excluding the cost of lease acquisitions.
- Acquired Ivanhoe Energy's U.S.-based assets of 2.2 million barrels of oil reserves for $34.9 million (after closing adjustments) for an average cost of $16 per barrel.

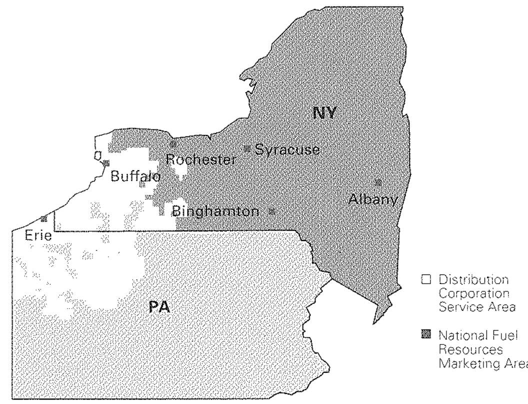
2010 Outlook

- Anticipate consolidated production of 42 to 50 billion cubic feet equivalent of natural gas.
- Anticipate Marcellus production of 30 to 50 million cubic feet per day by September 30, 2010.
- In the Marcellus Shale, will drill 25 to 35 horizontal wells through a Seneca-operated drilling program and at least 25 to 35 horizontal wells through a joint venture with EOG Resources.
- An increase of oil production for the third consecutive year in California.

1 Consolidated Operating Revenues as set forth in the Company's 2009 Statement of Income and Earnings Reinvested in the Business were $2,057.9 million. See page 111 of the Company's 2009 Form 10-K for details.

2 Consolidated Operating Income as set forth in the Company's 2009 Statement of Income and Earnings Reinvested in the Business was $224.8 million, including Exploration & Production, $6.1 million; Pipeline & Storage, $95.7 million; Utility, $124.8 million; Energy Marketing, $11.5 million; and Corporate and All Other, $(13.3) million.





Pipeline & Storage

National Fuel Gas Supply Corporation and Empire Pipeline, Inc. provide natural gas transportation and storage services to affiliated and nonaffiliated companies through an integrated system of 2,792 miles of pipeline and 31 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.

2009 Highlights

Operating Revenues: $219.3 million[1]
Operating Income: $95.7 million[2]
Net Income: $47.4 million
Capital Expenditures: $50.1 million
Total Assets: $1,046.4 million

- Incremental transportation revenues from the Empire Connector and other new services and contracts designed to move Appalachian local production.
- System throughput of 360.8 billion cubic feet, an increase of one percent compared to the previous year.

2010 Outlook

- Complete the Lamont Compression project, a 1,200 horsepower addition to an existing interconnect with Tennessee Gas Pipeline, capable of transporting 40,000 dekatherms per day of Marcellus production.
- Begin construction of the Line N Expansion Project, capable of moving 150,000 dekatherms per day of Marcellus Shale natural gas production to the Texas Eastern Transmission system in southwest Pennsylvania, expected to be in service in Fall 2011.
- Submit FERC certificate application for the Tioga County Extension, which is targeted to move Marcellus production from Tioga County, Pennsylvania, to the existing Empire Connector Pipeline and Corning, New York, the inlet of Millennium Pipeline.
- Continue to aggressively market and garner interest for the West-to-East/Appalachian Lateral Expansion, storage expansions and other system enhancements to serve increased Appalachian production.

1 Consolidated Operating Revenues as set forth in the Company's 2009 Statement of Income and Earnings Reinvested in the Business were $2,057.9 million. See page 111 of the Company's 2009 Form 10-K for details.

2 Consolidated Operating Income as set forth in the Company's 2009 Statement of Income and Earnings Reinvested in the Business was $224.8 million, including Exploration & Production, $6.1 million; Pipeline & Storage, $95.7 million; Utility, $124.8 million; Energy Marketing, $11.5 million; and Corporate and All Other, $(13.3) million.

Utility

National Fuel Gas Distribution Corporation sells or transports natural gas to customers through a local distribution system located in western New York and northwestern Pennsylvania.

2009 Highlights

Operating Revenues: $1,113.0 million[1]
Operating Income: $124.8 million[2]
Net Income: $58.7 million
Capital Expenditures: $56.2 million
Total Assets: $2,132.6 million

- Reduced operation and maintenance expense for the fourth consecutive year.
- Assisted qualifying customers in receiving $73 million in HEAP and LIHEAP funding in New York and Pennsylvania.

2010 Outlook

- Continue to operate system safely and reliably, focusing on cost containment and excellent customer service.
- Respond to the challenges of managing accounts receivable balances and declining usage per account.
- Monitor return on rate base and seek rate relief as needed.
- In New York, continue to administer effective conservation and efficiency programs.

Energy Marketing

National Fuel Resources, Inc. sells competitively priced natural gas to industrial, wholesale, commercial, public authority and residential customers primarily in western New York and northwestern Pennsylvania.

2009 Highlights

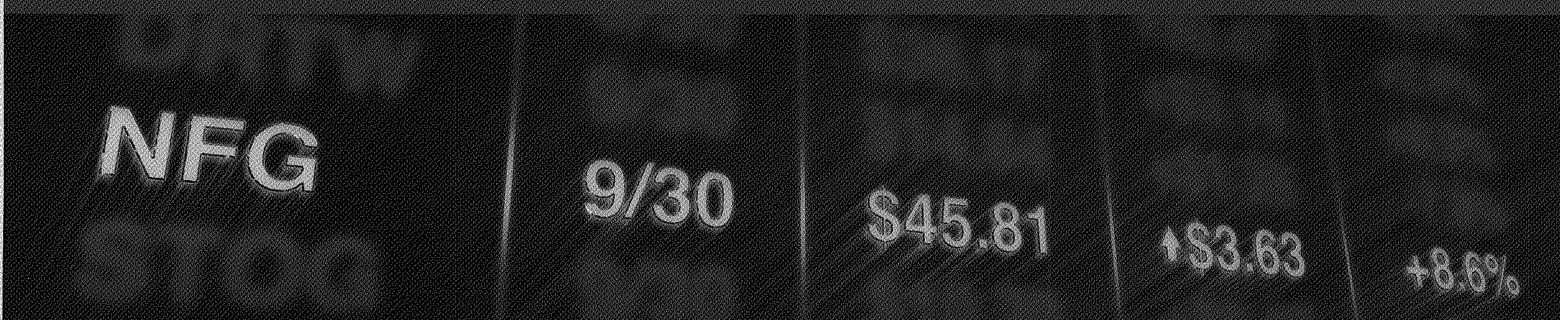
Operating Revenues: $398.3 million[1]
Operating Income: $11.5 million[2]
Net Income: $7.2 million
Total Assets: $52.5 million

- Sales volume of 60.9 billion cubic feet, an increase of more than eight percent compared to the previous year.

2010 Outlook

- Continue to focus on growth in core markets, and maintain existing customers.
- Provide energy solutions to residential, commercial and industrial customers.

To Our Shareholders



National Fuel Gas Company, listed on the New York Stock Exchange, had another impressive year of share appreciation, increasing in value by $3.63, or 8.6 percent during fiscal year 2009.

Dear Shareholder,

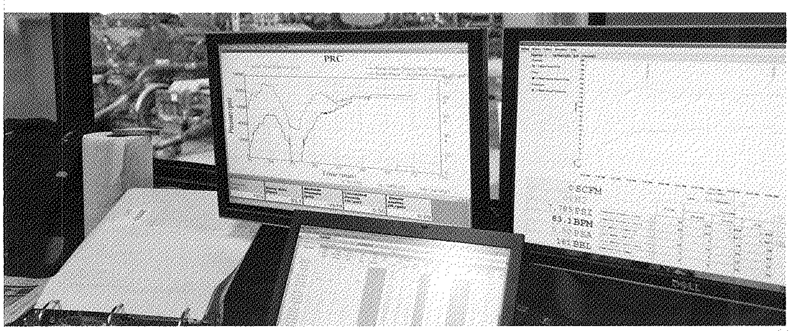
Fiscal Year 2009 was another remarkable year for National Fuel. During one of the most volatile and uncertain business environments that the United States has endured, we recognized earnings of $100.7 million, even after the effects of a non-cash ceiling test impairment that reduced earnings by $108.2 million. Perhaps more importantly, we generated more than $609 million in cash flow from operating activities. These results were achieved while we maintained a strong balance sheet – with a 56 percent equity component – and held more than $400 million in cash and temporary cash investments at year end.

In June 2009, your Board of Directors increased the dividend for the 39th consecutive year, marking our 107th year of uninterrupted payments. Reflecting the market's recognition of our achievements, the Company's stock provided shareholders a total return of 13 percent for the fiscal year. The calendar year ending December 31, 2009, was even better—our stock provided a total return of 65 percent to shareholders, comparing very favorably against a 25 percent total return in the S&P 500 Index, a 39 percent total return in the S&P Oil and Gas Exploration and Production Index, and a 21 percent total return in the S&P 400 Utilities Index.

In 2009, National Fuel achieved a fourth place ranking in the annual *Public Utilities Fortnightly* list of Best Energy Companies. National Fuel has been listed in the *Fortnightly* top 40 list since its inception five years ago, and among the top 10 in each of the last four years. The metrics utilized by *Fortnightly* to determine a company's rank include four-year averages of profit margin, dividend yield, free cash flow, return on assets and sustainable growth. These are areas where we have performed well for many years, thanks in large part to our diversified, integrated business model.

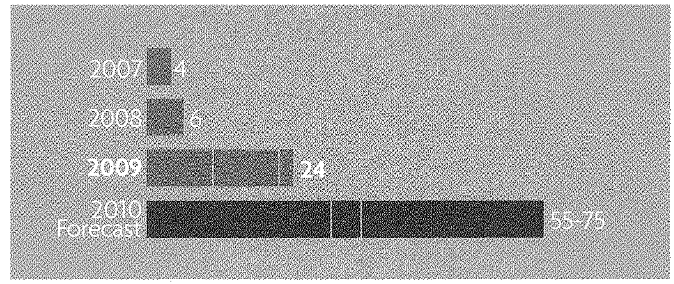
In addition to our overall financial performance, we are justly proud of the Company's operational achievements in 2009. Our record shows once again that your Company's words translate to actions.

In our Exploration and Production segment, comprised of Seneca Resources Corporation, total production for 2009 was 42.5 billion cubic feet equivalent (Bcfe), an increase of four percent over the prior year. We replaced 160 percent of Seneca's total production and had a net increase of more than 25 Bcfe of reserves. These results were achieved largely through our efforts in Appalachia, where we replaced an impressive 341 percent of production, and added proved reserves in the Marcellus Shale at an average finding and development cost of $1.28 per thousand cubic feet, excluding the cost of lease acquisitions.



Hydraulic fracturing is a process used to stimulate the flow of natural gas from the rock formations where the gas is located. Here, microseismic monitoring is used to measure the orientation and effectiveness of a hydraulic fracture in one of Seneca's Marcellus wells.

Marcellus Shale Wells Drilled Per Year



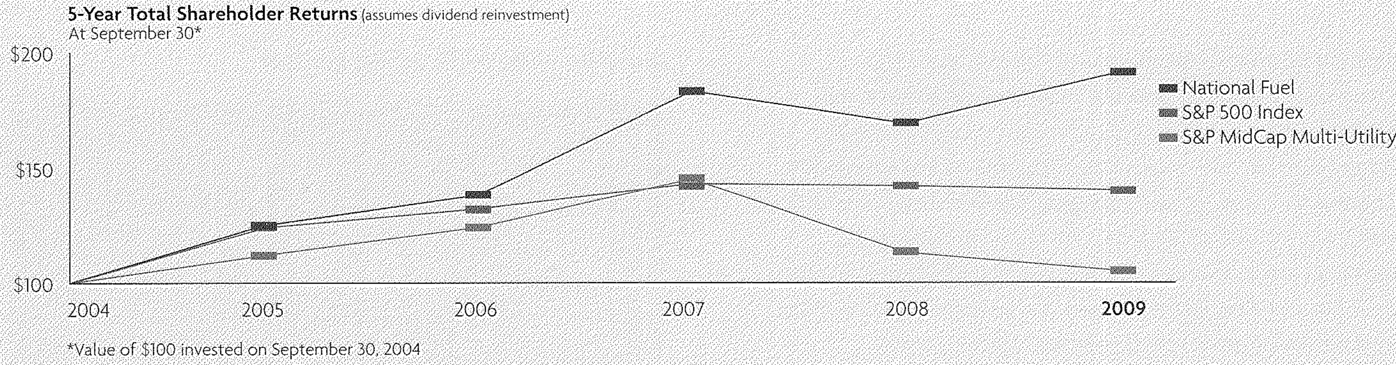
2007 4 EOG JV
2008 6 EOG JV
2009 11 EOG JV, 10 Seneca Vertical, 3 Seneca Horizontal
2010 Forecast – 25-35 EOG JV, 5 Seneca Vertical, 25-35 Seneca Horizontal – Total 55-75

Seneca's Marcellus Shale drilling program began in 2006 through a joint venture with EOG Resources, who acts as operator on a portion of Seneca's acreage. This year, Seneca began its own Marcellus drilling program and Seneca's first independently operated well flowed at an average rate of nearly six million cubic feet per day for the first week of production, and its most recent well recorded a rate of nearly 10 million cubic feet per day over its first week. As of the date of this letter, we have participated, through the EOG joint venture and in our own program, in the drilling of 24 horizontal wells in the Marcellus, including eight operated by Seneca. Since initiating this program Seneca has doubled its staff of geologists, engineers and industry experts, and has achieved operating results equivalent to best-in-class peers. Based on our activity to date, we estimate there is between four and eight trillion cubic feet of risked resource potential in our 720,000 net acres of mineral rights in the Marcellus Shale, the vast majority of which we own outright.

We benefited from the diversity among our Exploration and Production assets, as our California oil producing properties helped temper the steep decline in natural gas prices that occurred during the course of the year. To add to our position in California, we made a $34.9 million "bolt-on" acquisition, and we expect next year to once again increase production from the region.

In the Pipeline and Storage segment, we enhanced our focus in Appalachia by adding new transportation and storage contracts

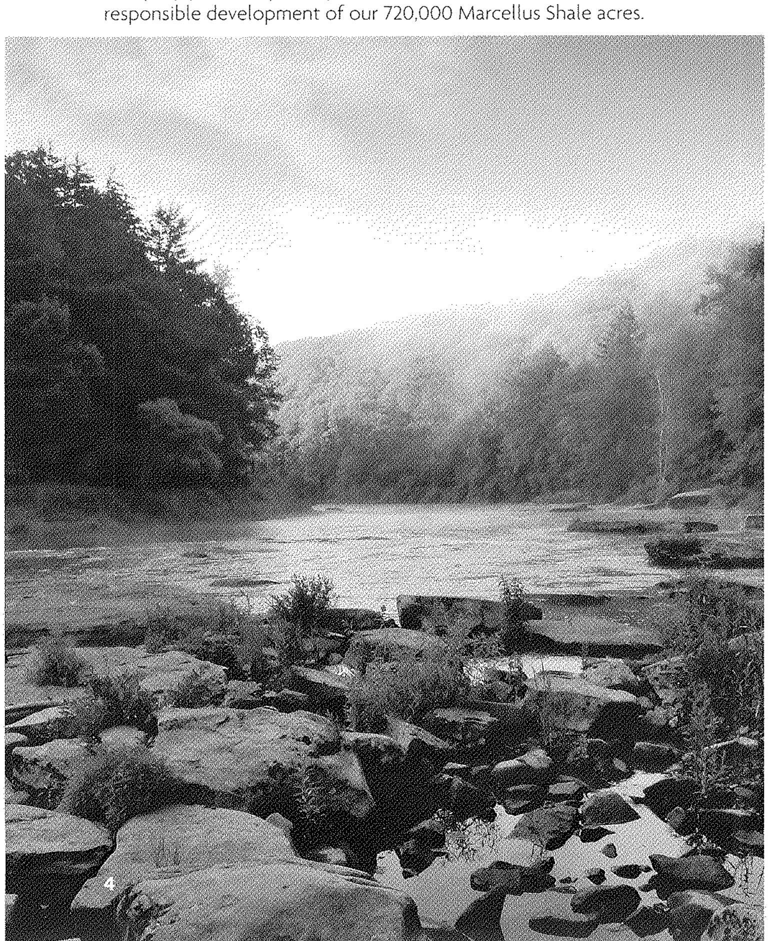
National Fuel Gas Midstream Corporation began construction on the Covington Gathering System in July 2009. The System, located in Tioga County, Pennsylvania, began flowing gas on November 17, 2009, and serves natural gas producers in the region, including Seneca, with a design capacity of 100 million cubic feet per day.



and completing several infrastructure projects. We also made progress identifying and pursuing interested shippers for our previously announced West-to-East Pipeline Project, including the Appalachian Lateral.

The Utility remains an important part of our integrated model, and was the largest contributor to GAAP earnings during the fiscal year. Given its low growth due to economic conditions and customer conservation, the Utility continued its focus on cost containment, and we were able to reduce operation and maintenance expense for the fourth consecutive year. Notably, we achieved these significant savings while maintaining our consistently high levels of safety and customer service. We are also proud of our very successful efforts in assisting customers to secure $73 million of heating assistance through the federal Home Energy Assistance Program. In the Utility, we intend to continue our long history of providing exceptional customer service, controlling costs and filing rate cases only when absolutely necessary.

The Clarion River in Pennsylvania, and its surrounding terrain, is an area that is prospective for the Marcellus Shale. Over the next two years, the Company plans to spend up to $550 million to continue the environmentally responsible development of our 720,000 Marcellus Shale acres.



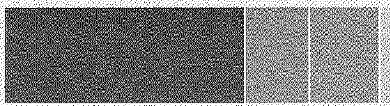
For 2010 we will aggressively build upon our success in Appalachia. We look to make more than 85 percent of the Exploration and Production investment in Appalachia.

Your Company's approach to business opportunities has long been guided by what I believe to be a healthy dose of pragmatism. It is because of this approach that National Fuel has not merely survived, but has continued to grow and thrive. We size up opportunities with the long view and announce projections with respect to those opportunities only when we believe that those projections can be actually achieved. Right now, I am happy to report that your Company is presented with more and greater opportunities than possibly ever before in its history. For this reason, while it is gratifying to recount the outstanding year that recently concluded, it is more important to talk about the future, and how we plan to address opportunities in ways that will serve your Company's best interests over the long run.

In 2010, we will aggressively build upon our success in Appalachia. Three years ago, we spent more than 70 percent of our Exploration and Production capital in Canada and the Gulf of Mexico. Since then, we sold our Canadian assets and have continued to trend away from significant new investment in the Gulf of Mexico. In 2010, we expect to allocate more than 85 percent of our Exploration and Production investment to Appalachia.

Our emphasis on Appalachia is most pronounced in the Marcellus Shale, where we look forward to significant production growth. For fiscal 2010, current plans call for the allocation of $200 million toward Marcellus Shale development, our participation in 55-75 wells, and

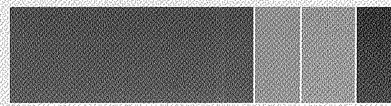
2009 Capital Expenditures by Segment
[in millions]



Exploration & Production[1]	$188.3
Pipeline & Storage[2]	$50.1
Utility	$56.2
Energy Marketing & All Other[3]	$8.4
Total[4]	**$303.0**

1 Includes $9.1 million of accrued capital expenditures, primarily from the Appalachian Region.
2 Excludes $16.8 million of capital expenditures related to the Empire Connector project, which were accrued at September 30, 2008 and paid during fiscal 2009.
3 Includes $0.7 million of accrued capital expenditures related to the construction of the Midstream Covington Gathering System.
4 Absent the adjustments in footnotes 1-3, total Capital Expenditures were $309.9 million, as set forth in the Company's 2009 Statement of Cash Flows.

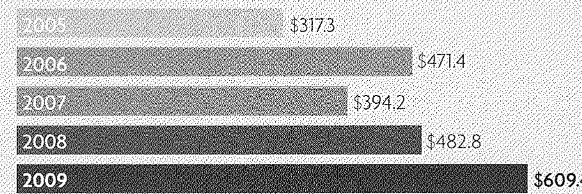
2010 Forecast Capital Expenditures by Segment [in millions]



Exploration & Production[1]	$255.0
Pipeline & Storage	$51.0
Utility	$60.0
Midstream	$45.0
Energy Marketing & All Other	$2.0
Total	**$413.0**

1 Includes estimated expenditures of approximately $42 million to develop proved undeveloped reserves.

Net Cash Provided by Operating Activities
[in millions]



net production to Seneca of 30 to 50 million cubic feet per day at the end of the year. In 2011, we estimate $350 million of investment towards Marcellus development, up to 130 wells being drilled, and a net production rate of 60 to 100 million cubic feet per day at the end of the year. This activity supports our expectation of double-digit production increases.

In our Pipeline and Storage segment, we are poised to grow the business with more than one billion dekatherms per day of transportation projects in various stages of development. Our

National Fuel has generated nearly $2.3 billion in operating cash flow over the past five years.

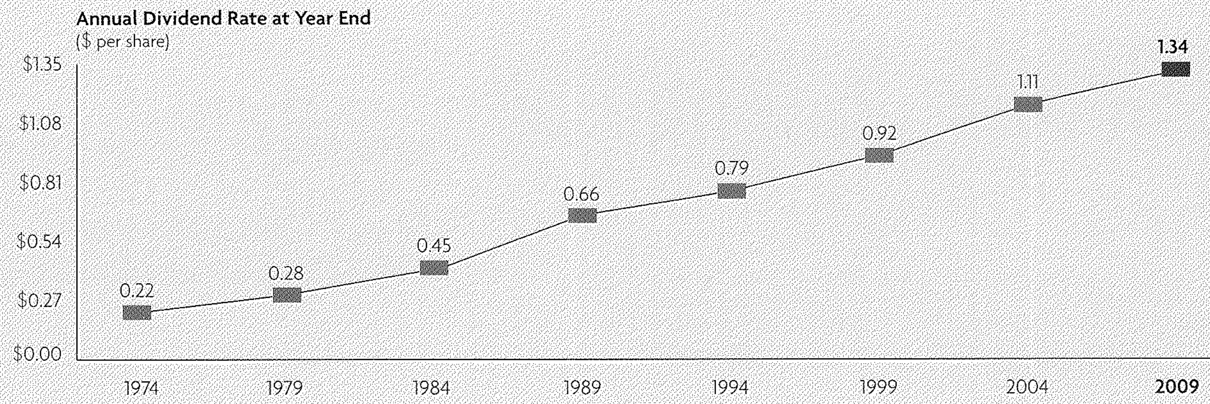
geographic advantage is more evident than ever, as we continue to identify opportunities with Seneca and third party producers looking for transportation services from emerging and established production areas to the markets where that gas is consumed. We anticipate that as much as $500 million could be spent in this segment over the next three years.

I am also pleased to report that we have made substantial progress in our most recently formed operating subsidiary, National Fuel Gas Midstream Corporation. Midstream was organized to construct gathering facilities primarily to bring Seneca's growing Appalachian production to market. In November 2009, Midstream completed a gathering system to collect and move Seneca's Marcellus production from Tioga County, Pennsylvania to Tennessee Gas Pipeline. Looking ahead, Midstream is considering more than a dozen projects to serve Seneca and other producers in Appalachia.

These and other potential projects reflect National Fuel's flexible, yet evolving business model. Although nearly $2 billion of potential investment in Appalachia by our Exploration and Production and Pipeline and Storage segments will shift the balance of capital among our operating segments, the basic tenet of our model will remain intact. We have long believed and continue to believe, that the diversity of our business segments, providing synergies and a natural hedge, serves our shareholders and customers well. We are not, however, wedded to a static balance of investments among the segments, or any preordained allocation of capital, as an end unto itself. Rather, we will make investments where the opportunities are greatest, and right now and likely for the foreseeable future, those opportunities are in Appalachia. It nonetheless remains the Company's objective that each segment continue to make a meaningful contribution to the whole, assuring that the diversified model that has distinguished National Fuel from its peers will continue to provide the same benefits going forward.

While we are eyeing significant projects that will continue to grow the Company, we do not foresee the need to issue equity in order to

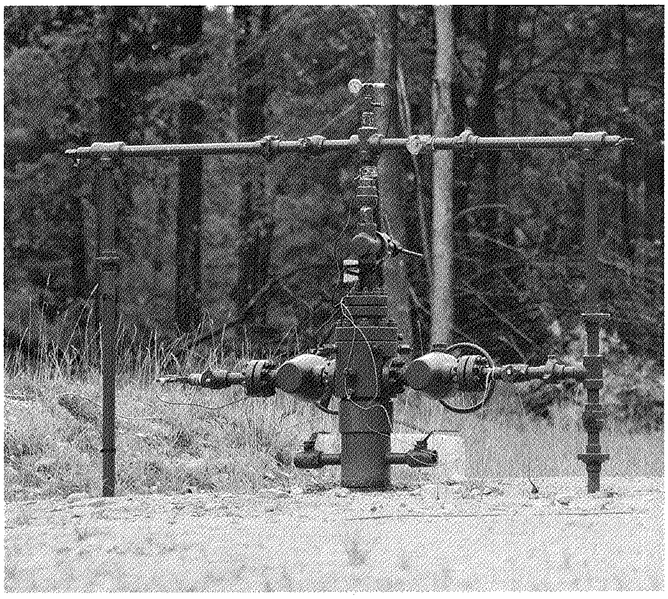
Pictured here are tanks that store water used as part of the hydraulic fracturing process, which stimulates the flow of natural gas from deep rock formations. Seneca takes exceptional measures to conserve and protect water resources, including recycling and reusing frac water.



fund that activity. In fact, we expect to maintain a strong balance sheet over the next three years with our equity component ranging between 50 and 60 percent. We believe that this is achievable based in large part on cash flow projections for Seneca.

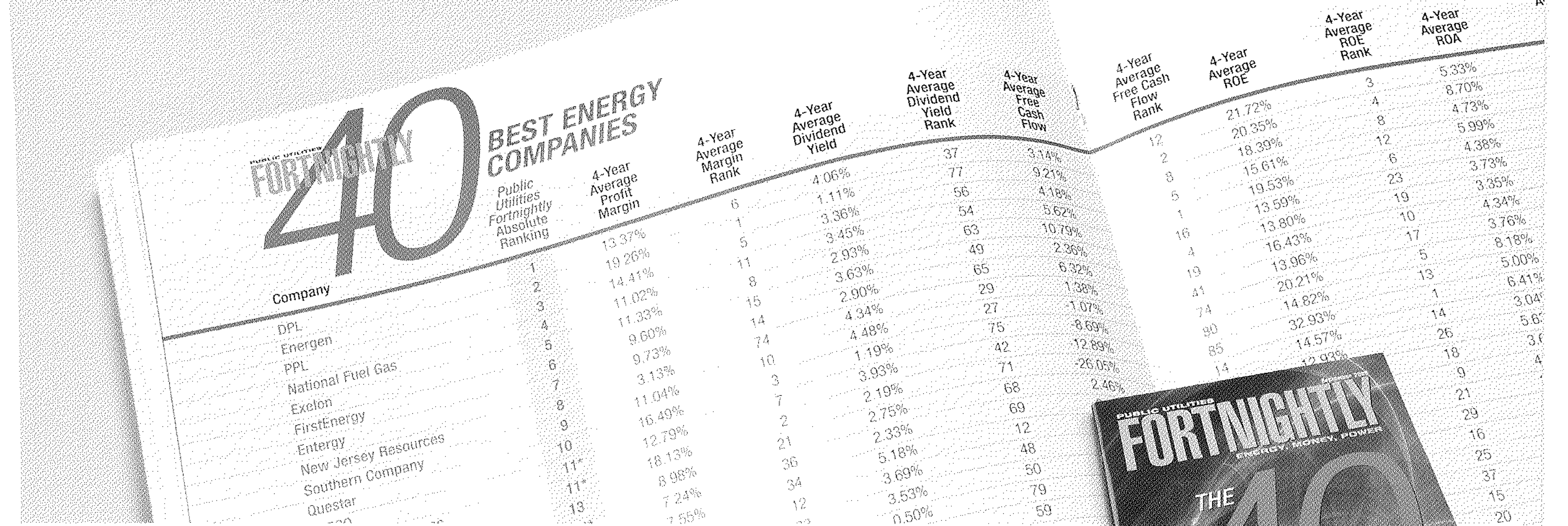
Nationally, 2009 was a year of significant change in the energy sector. We witnessed developments in federal and state laws, including an effort for broad energy legislation and other initiatives designed to decrease the nation's usage of, and reliance on, fossil fuels. We support the efficient and intelligent use of natural gas, and believe that conservation programs are a wise and necessary part of the overall energy solution. We disagree, however, with the notion advocated by some, that natural gas is indistinguishable, for purposes of environmental legislation, from other fossil fuels. Different fossil fuels have widely varying environmental impacts. Natural gas is the cleanest burning of all the fossil fuels, with approximately one-half of the carbon emissions of coal. In addition, the natural gas industry has a long record of using low-impact, environmentally sound extraction technologies. New legislation should recognize these established benefits, as well as the fact that natural gas production will mean new jobs and prosperity in production areas that are in need of economic revitalization.

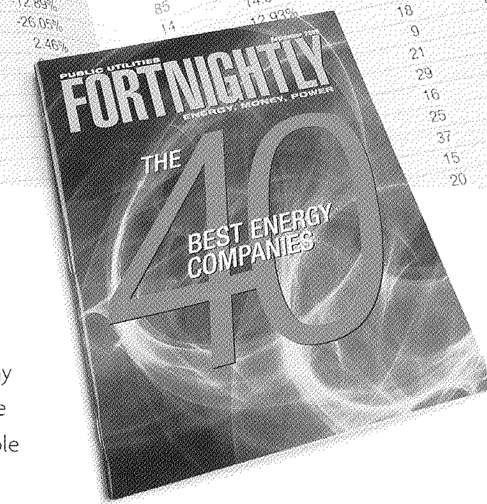
Individual wellheads, as shown below, have a minimal impact on the environment. In our Marcellus Shale drilling program, Seneca plans to further minimize environmental impact by drilling a number of horizontal wellbores from a single drilling pad.



Increased production and utilization of natural gas would also help to improve the nation's energy security. Perhaps the single greatest development regarding natural gas, and a game-changer in my opinion, is the recognition of its vast abundance as a recoverable fuel. For decades, natural gas was considered to be a fuel source that was both scarce and depleting, and therefore an unsuitable choice for the nation's long-term energy needs, particularly in electric generation markets. That mindset resulted in policies and practices which, for many years, favored coal over natural gas. The lingering effect of this long-held belief remains an impediment that, to this day, risks legislative decisions that are contrary to sound public policy. We will continue to work with our industry partners and advocacy groups to deliver the message that natural gas is the best energy choice for addressing the nation's current and long term energy security, economic and environmental needs.

In 2009, there were a few notable changes in Management at National Fuel. Mike Kasprzak and Michael Colpoys were both promoted to the positions of Assistant Vice President, at National Fuel Gas Supply Corporation and National Fuel Gas Distribution Corporation, respectively. Mike Kasprzak has been with the Company for 28 years, concentrating on work in Compression Services, Supply Field Operations and Distribution Operations, most recently overseeing the installation of the Oakfield compressor station as part of the Empire Connector project. Michael Colpoys has worked at National Fuel for 22 years, in various positions in Pennsylvania Distribution and Supply Operations. Both will be dedicating their considerable expertise to the management of our regulated businesses and the development of expansion projects.





National Fuel Gas Company was recognized by *Public Utilities Fortnightly* as the 4th Best Energy Company for 2009. The Company has been consistently ranked in the report's top 10 during the past four years.

National Fuel, and its employees, continued their long record of commitment and dedication to the communities in which we operate. Employee volunteers donated their time and more than $450,000 in cash to non-profit organizations over the last year. Through the National Fuel Gas Company Foundation, another $447,000 was provided to supplement the worthy causes identified by the employees, and to support other admirable initiatives. Over the last five years, employees and the Company together have donated more than $4.4 million to charitable organizations.

I believe that our history of success is directly attributable to the hardworking employees of National Fuel and the retirees before them. We are an organization of people who have built an institution that reflects shared values of dedication, creative initiative and teamwork. These attributes have enabled the Company to generate extraordinary shareholder value and customer service again in 2009.

In last year's Annual Report, I closed my letter with a statement of confidence that the Company would maintain a steady course through a period of difficult economic times. That, indeed, is exactly what we did. As we close out another year of uncertainty and turbulence in the economy, I can again state with confidence that your Company is well positioned for success not only in 2010, but also for the long run. Although this Company is undoubtedly in a period of change – albeit positive change – the value proposition we offer to shareholders remains simple and constant. We are a company backed by real, tangible assets in the form of proven reserves, pipelines serving growing markets, and distribution facilities serving hundreds of thousands of retail customers. We are also a company with significant opportunities, and the ability, motivation and expertise to turn those opportunities into achievements. It is for all of these reasons that I look forward to the coming year and National Fuel's continued success.

David F. Smith
President and Chief Executive Officer
January 12, 2010

Exploration & Production

In July 2009, Seneca Resources purchased Ivanhoe Energy's U.S.-based operations, predominantly oil producing properties, in the Midway Sunset Field in California. This "bolt-on" acquisition immediately added approximately 600 net barrels per day of production to Seneca's West Division, while requiring the addition of only one employee.

Seneca Resources Corporation, our Exploration & Production subsidiary, had one of its best operating years in history, replacing 160 percent of production and adding a net 25 billion cubic feet equivalent of reserves. In addition, total production increased four percent to 42.5 Bcfe. Most importantly, Seneca made significant progress in the development of its enormous resource potential in the Marcellus Shale.

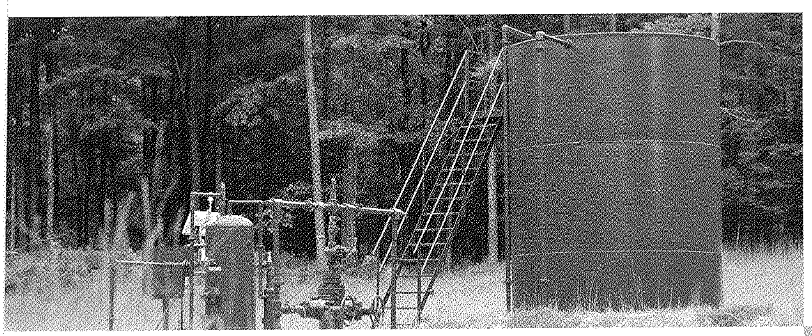
Despite the higher production, Seneca posted a loss of $10.2 million compared to earnings for the prior year of $146.6 million. The decrease in earnings was largely related to a non-cash ceiling test impairment charge of $108.2 million in the first quarter of the fiscal year, primarily the result of significant decreases in crude oil and natural gas prices.

Capital expenditures and investments in subsidiaries in the Exploration & Production segment increased to $223 million for fiscal year 2009, with more than 60 percent of this spending in Appalachia. Seneca made two large investments during the fiscal year. The first was the leasing of Pennsylvania acreage in Tioga and Lycoming Counties prospective for the Marcellus Shale, and the second was a "bolt-on" addition to our oil producing properties in California. In fiscal year 2010, total capital devoted to Exploration & Production is expected to be approximately $255 million, including further development in Appalachia, which will receive more than 85 percent of this capital.

The Marcellus Shale is the focus of our development efforts as we move forward with an increasingly aggressive plan for our 720,000 net prospective acres. Seneca initiated its independently operated drilling program in the Marcellus Shale in March 2009. To date, 11 vertical wells have been drilled across seven counties in Pennsylvania, and conventional core samples have been taken in order to prioritize our acreage for development.

Seneca has also drilled eight horizontal wells, to date, in the Marcellus Shale under its independent program. Three of these wells were completed and flowed at a seven-day combined rate of more than 20 million cubic feet per day. In addition to the Seneca-operated activity, we continued to participate with our joint venture partner, EOG Resources, in a total of 16 horizontal wells. Seneca plans to drill between 25 to 35 horizontal wells in fiscal year 2010, with the help of a second horizontal drilling rig that arrived on-site in November 2009. By the end of 2010, we plan to have identified two to three additional focus areas for developmental drilling. EOG operates two rigs in the Marcellus Shale and will drill approximately 25 to 35 horizontal wells for the joint venture in fiscal year 2010.

With data acquired during the past year, we were able to estimate our risked resource potential in the Marcellus Shale play at four to eight trillion cubic feet. This estimate is based on 100-acre spacing and ultimately producing two to three billion cubic feet per well drilled on 30 to 40 percent of our acreage position. In 2009, we added 21.2 billion cubic feet of Marcellus Shale reserves at an average finding and development cost of $1.28 per thousand cubic feet, excluding the cost of lease acquisition. Assuming that our escalated activity continues as planned, we now anticipate production rates from the Marcellus Shale of 30 to 50 million cubic feet per day by September 30, 2010, and 60 to 100 million cubic feet per day one year later, net to Seneca.



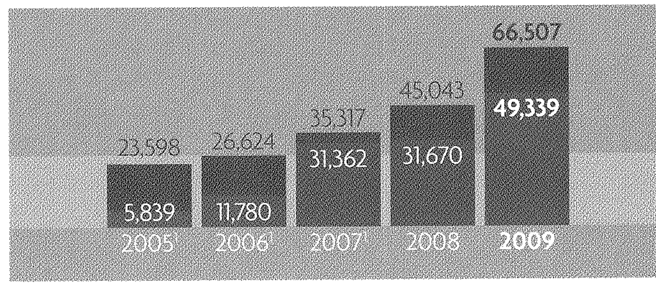
Once a Marcellus well is completed and ready to produce gas, the well site leaves minimal impact on the environment. The original drill site is restored to a natural condition and the production facilities occupy a very small area.

With an expected drilling inventory of 3,000 to 4,000 gross wells in the Marcellus Shale, this will be an area of continued expansion, with capital spending of $200 million and $350 million currently budgeted for fiscal years 2010 and 2011, respectively.

In our Upper Devonian conventional drilling program in Appalachia, we continued to make strong progress, with our third consecutive year of production increases. We drilled 195 wells in fiscal 2009, and expect to drill approximately 150 wells in fiscal 2010.

In California, we were able to increase oil production for the second consecutive year, and continued our status as a low-cost operator. The West Division was also an important contributor to earnings, as the price of oil remained relatively strong compared to the price of natural gas in 2009. In July 2009, we completed the purchase of Ivanhoe Energy's U.S. oil and gas properties, predominantly in the Midway

Domestic Extensions and Discoveries (MMcfe)



■ Total Domestic Extensions and Discoveries
■ Total Appalachian Extensions and Discoveries

1 2005, 2006 and 2007 exclude Canadian operations. The Company sold its Canadian operations in 2007.

Sunset Field. After closing adjustments, we paid $34.9 million for 2.2 million barrels of proved reserves, or approximately $16 per barrel.

Although the Gulf of Mexico is an area we continue to de-emphasize, in July 2009, these assets produced 50 million cubic feet equivalent per day, their highest rate in more than four years. For fiscal year 2010, with minimal capital spending, we expect production of 11 to 13 billion cubic feet equivalent.

In summary, we anticipate total Seneca production in fiscal 2010 to be in the range of 42 to 50 billion cubic feet equivalent, approximately eight percent higher than fiscal year 2009 at the midpoint of the range. As we continue to accelerate our Marcellus development, we are expecting overall production increases of approximately 20 percent per year in fiscal years 2011 and 2012, with continued growth for many years beyond.

Since Seneca initiated its independent drilling program in March 2009, it has drilled and completed three wells in Tioga County, Pennsylvania, the most recent of which produced more than 10 MMcf of natural gas in its first day. This picture shows the rig that completed this drilling, and with the help of a second rig that arrived in November 2009, Seneca plans to independently drill another 25-35 horizontal wells in fiscal 2010.

Pipeline & Storage

Supply plans to seek regulatory approval to replace and relocate the Line N natural gas pipeline and construct a compressor station in Pennsylvania, in Greene and Washington Counties. This project will help improve the reliability and increase the capacity of the existing pipeline system, which transports natural gas from Appalachia to markets in western Pennsylvania and throughout the northeast. This project has an anticipated in-service date of November 2011.

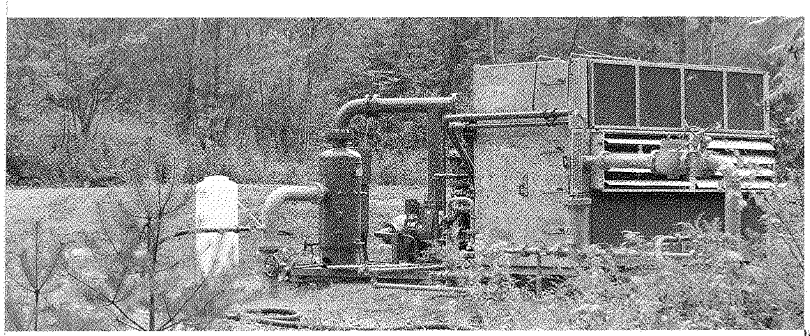
The Pipeline & Storage segment posted earnings of $47.4 million in fiscal year 2009. Transportation revenues increased as a result of new firm transportation contracts in Appalachia, where we have focused our efforts, and because of revenues generated by the Empire Connector Pipeline that went into service in December 2008. These gains, however, were more than offset by higher interest and depreciation costs, a lower allowance for funds used during construction, and lower efficiency gas revenues.

Going forward, we plan to continue our long-term investment strategy for this segment in order to maximize the natural advantage of our geographic location. Much of Empire Pipeline, Inc., and National Fuel Gas Supply Corporation's transmission and storage assets are located in Appalachia, and our pipeline network overlays the Marcellus Shale. Successful development of the Marcellus Shale play – for Seneca and unaffiliated producers – will require significant investment to assure market access for new production. We are very well positioned to satisfy the increased demand for pipeline and storage capacity with our existing and planned facilities. In fiscal year 2010, capital spending is estimated to be $51 million, and based on expansion opportunities, spending should increase significantly in fiscal years 2011 and 2012 as a number of projects are developed.

The planned West-to-East (W2E) Project, with its companion Appalachian Lateral, is the largest of our infrastructure projects proposed in Appalachia. This project is under way and, given its significant scope, is progressing in stages. In October 2009, we concluded a binding Open Season for Phases I and II of the W2E/Appalachian Lateral, aimed at moving Marcellus Shale production from various counties in central Pennsylvania to the Leidy Hub, an interstate pipeline interconnect providing access to eastern markets. W2E/Appalachian Lateral has attracted a significant amount of interest, and our marketing team is currently working with bidders and other interested parties to finalize agreements supporting construction of the facilities.

Supply is also preparing a Federal Energy Regulatory Commission certificate filing for its Line N Expansion Project. Backed by a key Marcellus Shale producer in southwestern Pennsylvania, this expansion will provide incremental transportation of 150,000 dekatherms per day to the point furthest south on Supply's system, an interconnect with Texas Eastern Transmission in Holbrook, Pennsylvania. It is anticipated that this expansion will be in service in November 2011.

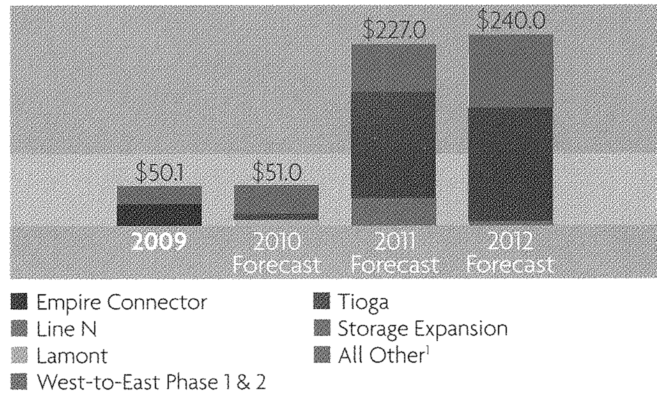
One of the more imminent projects that we hope to have in service as early as May 2010, is the addition of incremental compression at the Lamont Station on Supply's system. This $6 million, 1,200 horsepower expansion will allow for 40,000 dekatherms per day of incremental delivery capacity from Elk and Cameron Counties, Pennsylvania, to Supply's interconnection with Tennessee Gas Pipeline's interstate pipeline facilities.



The R-49 compressor pictured above was installed in 2009 to help bring local gas production from existing wells owned by Seneca and third-party producers to market.

Empire conducted an Open Season for the Tioga County Extension, a project that will transport Marcellus Shale production from Tioga County, Pennsylvania to the Millennium Pipeline, the Chippawa, Ontario, interconnect with TransCanada Pipeline, and a newly proposed interconnect with Tennessee Gas Pipeline in Ontario County, New York. This 16-mile extension has a projected in-service date of September 2011, and is designed to transport at least 200,000 dekatherms per day.

Capital Expenditures by Project [in millions]



1 All other includes additions, improvements, and replacements to Supply's transmission and gas storage systems.

Our objective remains to further capitalize on the synergies presented by National Fuel's diversified model. Perhaps nowhere else in our business are those synergies better exemplified than in the Pipeline & Storage segment's location of assets across a wide area prospective for the Marcellus Shale. The projects described above were conceived as opportunities arising from this segment's locational advantage, and today those opportunities are under development. With more than one billion dekatherms per day of transportation and storage projects in various stages of development, the Pipeline & Storage segment will continue to be integral to National Fuel's long-term growth.

Supply employees plan and implement projects to expand our system and maximize our geographic advantage in the heart of Appalachia and the Marcellus play. Pictured here (left to right) are: Jeff Kittka, General Manager of Engineering Services; Ron Kraemer, Vice President; and Mike Kasprzak, Assistant Vice President.

Utility

Our Utility segment has provided safe and reliable service to customers in western New York and northwestern Pennsylvania for more than 100 years. Here, the Utility replaces a 16" pipeline on South Park Avenue in Buffalo, New York.

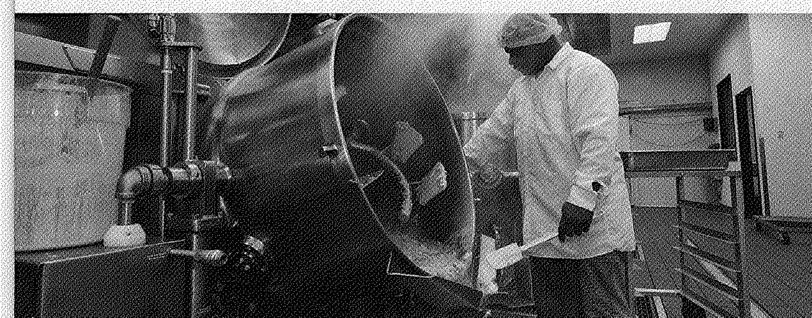
National Fuel Gas Distribution Corporation posted earnings of $58.7 million, a decrease of $2.8 million compared to the previous year. This decrease was the result of higher interest expense, lower normalized usage per account in our Pennsylvania jurisdiction, the negative impact of a rate design change in New York, and higher effective income tax expense. These negative effects were minimized, however, by a reduction in operating expenses of $3.5 million and colder than normal weather in Pennsylvania.

In our New York service territory, fiscal year earnings were $37.7 million, a decrease of $3 million compared to the previous year. This was primarily the result of a rate design change, effective in December 2007. For 2009, this meant that revenues early in the year were down compared to the same period in the prior year. Prospectively, this rate design change will help stabilize monthly customer bills and minimize spikes during the heating season. Higher interest expense also contributed to the decrease, which was partially offset by lower operating expenses.

In Pennsylvania, earnings were $21 million, an increase of $0.2 million compared to the previous year. Although the Pennsylvania Division experienced an increase in interest expense, as mentioned above for New York, and experienced a decrease in normalized usage per account, the resulting effect on earnings was more than offset by reduced operating expenses and colder weather.

Given its limited growth opportunities, the Utility segment has long focused on controlling costs in order to achieve its allowed return on rate base. Indeed, the Utility segment's dedicated and capable work force has reduced costs for four consecutive years. And while cost control is clearly an ongoing effort, it has not diminished the Utility's continued emphasis on safety and quality of service. During fiscal year 2009, we spent $56.2 million on system upgrades, to ensure that our pipeline network continues to operate safely and reliably. We also closely monitor telephone response time, customer service and our ability to quickly respond to emergency issues, exceeding performance metrics set by regulators.

Going forward, the Utility faces several challenges. Conservation and efficiency programs continue to capture the attention of regulators and customers. In New York, our successful Conservation Incentive Program (CIP) has commenced its third year. Through the CIP rebates and other incentives, thousands of New York customers have installed new, energy efficient appliances and undertaken other conservation



A new, 27,000 square foot state-of-the-art Commissary for Meals on Wheels for Western New York, pictured here, received a 2009 grant from the New York Utility Division's Area Development Program.

measures that will help to drive down their energy costs over the long run. We continue to support the CIP and other effective energy efficiency initiatives in New York because we have long advocated for the efficient use of natural gas, and further because of the protection afforded the New York Division by a revenue decoupling mechanism. Although Pennsylvania has not yet adopted a revenue decoupling mechanism, together with other utilities we continue to press for its approval so that the interests of the Utility and its customers can be aligned in the pursuit of beneficial energy conservation objectives.

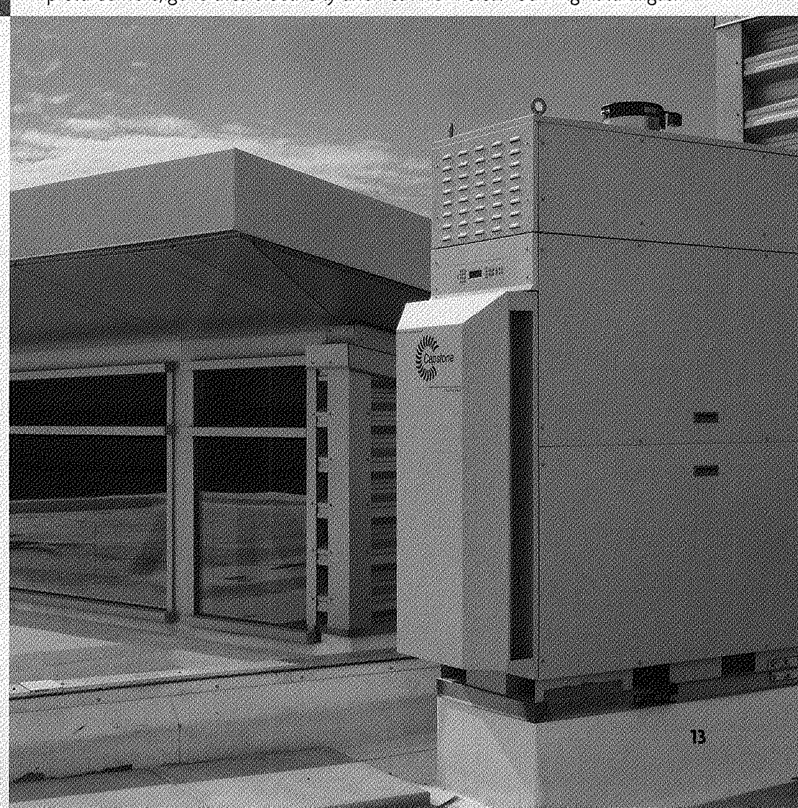
A particular challenge in the current economic downturn will be managing our aged accounts receivable balance. Toward that end, to help customers pay their gas bills, we will continue our efforts, in

Utility Net Income [in millions]

collaboration with government agencies, to ensure that robust federal assistance is allocated to our service territories and distributed to qualified customers.

Finally, the effects of a sluggish economy and increased customer conservation efforts will require us to closely monitor the need to file rate cases. Most major utilities in New York and Pennsylvania have found it necessary to seek rate relief in the past two years, in some cases more than once. Largely because of our aggressive cost containment practices, we have managed to avoid the need to file a rate case since 2006 in Pennsylvania, and 2007 in New York. As a result, our customers have experienced the benefit of stable delivery charges. We expect to continue the same cost containment practices for 2010 in an effort to hold the line on rates while meeting our earnings objectives, and without compromising safety and the high quality of service our customers expect.

With the help of a grant from the Utility's research and development program, Clarion University of Pennsylvania established an advanced energy laboratory in its new Science & Technology Center. The National Fuel Energy Laboratory features a hybrid electric generation system that incorporates the synergies of a 65-kilowatt microturbine with solar panels producing supplemental electricity for use during high-load daytime periods. The microturbine, pictured here, generates electricity and heat from clean-burning natural gas.



Energy Marketing

NFR was chosen by the Amherst Chamber of Commerce to be its Premier Supplier of natural gas. Under the *Premier Natural Gas Supplier Program*, NFR offers its expertise and a membership discount in order to help businesses control their energy costs. Here, Bob Tullio, Sales Manager for NFR, discusses program benefits to Chamber members at the inaugural meeting.

The Energy Marketing segment, comprised of National Fuel Resources, Inc. (NFR), earned $7.2 million in fiscal year 2009, an increase of $1.3 million when compared to earnings of $5.9 million in fiscal year 2008. The improved results were primarily because of an increase in margin driven by lower pipeline transportation fuel costs. This also reflects improved average margin per thousand cubic feet and the non-recurrence of an unfavorable pipeline imbalance resolution that occurred in fiscal 2008. Higher pipeline reservation charges related to additional storage capacity partially offset these margin increases.

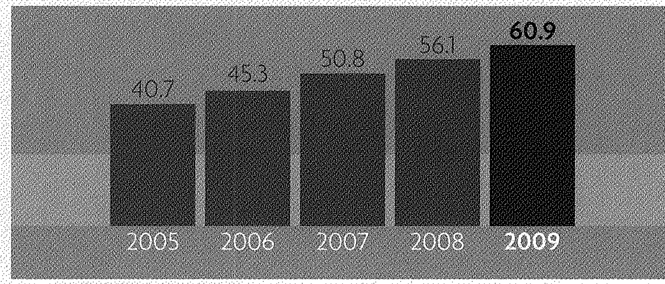
NFR continues to focus on steady growth based on competitive pricing, reliability, and strong customer service. Retail gas sales and certain incremental wholesale gas sales provided NFR with natural gas sales volume of 60.9 billion cubic feet, an increase of 4.7 billion cubic feet over the prior year. In addition to its solid footing as a market leader on National Fuel's utility system, NFR maintained its strong off-system performance on the National Grid, Rochester Gas & Electric, and New York State Electric and Gas utility systems with sales of 6.5 billion cubic feet.

In a year of unprecedented economic turmoil, many of NFR's commercial and industrial customers were seriously impacted by the downturn in the U.S. economy. Customer credit was a particular challenge. NFR was able to leverage its strengths in operations, sales and risk management to successfully respond to these challenges and finish the year with strong financial results. Additionally, NFR's key storage and transportation contracts enable it to operate in a flexible, reliable and strategic fashion that few marketers are able to match.

From residential households to large industrial customers, NFR offers years of experience and competitively priced natural gas to its diverse customer base in the complex natural gas marketplace. Representing National Fuel's deregulated retail end of the natural gas supply chain, NFR, as a major customer of both Supply and Empire, reflects the synergies of the Company's diversified model.

Going forward, NFR will continue to develop and market innovative natural gas supply choices for existing and potential customers, and pursue growth on National Fuel's utility system and in adjacent utility service territories.

NFR Natural Gas Marketing Volume (Bcf)



Corporate and All Other

National Fuel's other operating subsidiaries reported a loss of \$2.2 million for fiscal year 2009, compared to net income of \$0.6 million for fiscal year 2008. The loss for fiscal year 2009 includes a \$2.8 million loss related to an impairment of a landfill gas site and a \$1.1 million loss related to an impairment of Energy Systems North East, a regional gas-fired power production plant, following decreased utilization given the economic downturn and the resulting decrease in demand for electric power.

In November 2009, National Fuel Gas Midstream Corporation completed its first pipeline project, the Covington Gathering System. This project is designed to transport 100 million dekatherms of Marcellus Shale natural gas production per day, to Tennessee Gas Pipeline. With the increased drilling activity in the Marcellus, we expect this will be an area of continued investment, with \$45 million, \$20 million and \$20 million in capital expenditures currently estimated in fiscal years 2010, 2011 and 2012, respectively.

Other operating activities include a Timber business, operated by Highland Forest Resources, Inc., and the Northeast Division of Seneca Resources, that owns two sawmills and markets high quality hardwoods from the 106,741 acres of timber properties that we either own or manage. Horizon LFG, Inc., engages in the purchase, sale and transportation of landfill gas in six Midwestern states, and Horizon Power, Inc., develops and operates mid-range independent power production facilities and electric generation facilities powered by landfill gas.

Midstream spending over the next three years could total more than \$85 million, as there are more than a dozen projects under consideration.

Financial Highlights

Fiscal Year Ended September 30	2009	2008	2007	2006	2005
Operating Revenues (Thousands)[1]	$ 2,057,852	$ 2,400,361	$ 2,039,566	$ 2,239,675	$ 1,860,774
Net Income Available for Common Stock (Thousands)	$ 100,708[2]	$ 268,728	$ 337,455[3]	$ 138,091[2]	$ 189,488[4]
Return On Average Common Equity[5]	6.3%	16.6%	22.0%	10.3%	15.3%
Per Common Share					
Basic Earnings	$ 1.26	$ 3.27	$ 4.06	$ 1.64	$ 2.27
Diluted Earnings	$ 1.25	$ 3.18	$ 3.96	$ 1.61	$ 2.23
Dividends Paid	$ 1.31	$ 1.26	$ 1.21	$ 1.17	$ 1.13
Dividend Rate at Year-End	$ 1.34	$ 1.30	$ 1.24	$ 1.20	$ 1.16
Book Value at Year-End	$ 19.74	$ 20.27	$ 19.53	$ 17.31	$ 14.58
Common Shares Outstanding at Year-End	80,499,915	79,120,544	83,461,308	83,402,670	84,356,748
Weighted Average Common Shares Outstanding					
Basic	79,649,965	82,304,335	83,141,640	84,030,118	83,541,627
Diluted	80,628,685	84,474,839	85,301,361	86,028,466	85,029,131
Stock Average Daily Trading Volume	551,327	654,620	593,424	445,802	322,887
Common Stock Price					
High	$ 48.30	$ 63.71	$ 47.87	$ 39.16	$ 36.00
Low	$ 26.67	$ 38.04	$ 35.02	$ 29.25	$ 26.20
Close	$ 45.81	$ 42.18	$ 46.81	$ 36.35	$ 34.20
Net Cash Provided by Operating Activities (Thousands)	$ 609,432	$ 482,776	$ 394,197	$ 471,400	$ 317,346
Total Assets (Thousands)	$ 4,769,129	$ 4,130,187	$ 3,888,412	$ 3,763,748	$ 3,749,753
Capital Expenditures (Thousands)	$ 309,930	$ 397,734	$ 276,728	$ 294,159	$ 219,530
Volume Information					
Utility Throughput-MMcf					
Gas Sales	69,414	73,470	73,031	71,109	80,274
Gas Transportation	59,751	64,267	62,240	57,950	59,770
Pipeline & Storage Throughput-MMcf					
Gas Transportation	360,841	358,370	356,088	374,988	372,379
Production					
Gas-MMcf	22,284	22,341	26,266	25,771	29,179
Oil-Mbbl	3,373	3,070	3,450	3,608	3,869
Total-MMcfe	42,522	40,761	46,966	47,419	52,393
Proved Reserves					
Gas-MMcf	248,954	225,899	205,389	232,575	238,140
Oil-Mbbl	46,587	46,198	47,586	58,018	60,257
Total-MMcfe	528,476	503,087	490,905	580,683	599,682
Energy Marketing Volume-MMcf					
Gas	60,858	56,120	50,775	45,270	40,683
Average Number of Utility Retail Customers	624,149	627,938	645,723	669,731	674,633
Average Number of Utility Transportation Customers	103,176	98,925	79,676	57,713	56,262
Number of Employees at September 30[6]	1,949	1,943	1,952	1,993	2,044

(1) Excludes discontinued operations.

(2) Includes impairment of oil and gas producing properties of ($108.2) million in 2009 and ($68.6) million in 2006.

(3) Includes gain on sale of Seneca Energy Canada, Inc. of $120.3 million.

(4) Includes gain on sale of United Energy of $25.8 million.

(5) Calculated using average Total Comprehensive Shareholder Equity.

(6) Includes 0, 0, 0, 23, and 26 international employees at September 30, 2009, 2008, 2007, 2006, and 2005, respectively.

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

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, 2009

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to

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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☐ No ☑

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (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 $2,414,082,000 as of March 31, 2009.

Common Stock, $1 Par Value, outstanding as of October 31, 2009: 80,560,665 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2010 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

Glossary of Terms

Frequently used abbreviations, acronyms, or terms used in this report:

National Fuel Gas Companies

Company The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure

Distribution Corporation National Fuel Gas Distribution Corporation

Empire Empire Pipeline, Inc.

ESNE Energy Systems North East, LLC

Highland Highland Forest Resources, Inc.

Horizon Horizon Energy Development, Inc.

Horizon B.V. Horizon Energy Development B.V.

Horizon LFG Horizon LFG, Inc.

Horizon Power Horizon Power, Inc.

Midstream Corporation National Fuel Gas Midstream Corporation

Model City Model City Energy, LLC

National Fuel National Fuel Gas Company

NFR National Fuel Resources, Inc.

Registrant National Fuel Gas Company

SECI Seneca Energy Canada Inc.

Seneca Seneca Resources Corporation

Seneca Energy Seneca Energy II, LLC

Supply Corporation National Fuel Gas Supply Corporation

Toro Toro Partners, LP

U.E. United Energy, a.s.

Regulatory Agencies

EPA United States Environmental Protection Agency

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

NYDEC New York State Department of Environmental Conservation

NYPSC State of New York Public Service Commission

PaPUC Pennsylvania Public Utility Commission

SEC Securities and Exchange Commission

Other

Bbl Barrel (of oil)

Bcf Billion cubic feet (of natural gas)

Bcfe (or Mcfe) — represents Bcf (or Mcf) Equivalent The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. The Company 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.

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

Capital expenditure Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.

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 financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net, and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.

Development costs Costs incurred to obtain access to proved oil and gas 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.

Dth Decatherm; 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.

Exchange Act Securities Exchange Act of 1934, as amended

Expenditures for long-lived assets Includes capital expenditures, stock acquisitions and/or investments in partnerships.

Exploitation Development of a field, including the location, drilling, completion and equipment of wells necessary to produce the commercially recoverable oil and gas in the field.

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.

Firm transportation and/or storage The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.

GAAP Accounting principles generally accepted in the United States of America

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

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

Hedging A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.

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, and for which the customer does not pay unless utilized.

LIBOR London Interbank Offered Rate

LIFO Last-in, first-out

Mbbl Thousand barrels (of oil)

Mcf Thousand cubic feet (of natural gas)

MD&A Management's Discussion and Analysis of Financial Condition and Results of Operations

MDth Thousand decatherms (of natural gas)

MMBtu Million British thermal units

MMcf Million cubic feet (of natural gas)

MMcfe Million cubic feet equivalent

NGA The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.

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

Open Season A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.

Order 636 An order issued by FERC entitled "Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations."

PCB Polychlorinated Biphenyl

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 those reserves productive.

PRP Potentially responsible party

PUHCA 1935 Public Utility Holding Company Act of 1935

PUHCA 2005 Public Utility Holding Company Act of 2005

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 pipeline and/or utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or "unbundling") of 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.

S&P Standard & Poor's Ratings Service

SAR Stock-settled stock appreciation right

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

Stock acquisitions Investments in corporations.

Unbundled service A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.

VEBA Voluntary Employees' Beneficiary Association

WNC Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

For the Fiscal Year Ended September 30, 2009

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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 and important factors included in this Form 10-K at Item 7, 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, statements regarding future prospects, plans, objectives, goals, projections, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction and other projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may" and similar expressions.

PART I

Item 1 *Business*

The Company and its Subsidiaries

National Fuel Gas Company (the Registrant), incorporated in 1902, is a holding company organized under the laws of the State of New Jersey. Except as otherwise indicated below, the Registrant owns directly or indirectly 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 and reports financial results for four 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 727,000 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 Pipeline, Inc. (Empire), a New York corporation. Supply Corporation provides interstate natural gas transportation and storage services for affiliated and nonaffiliated companies through (i) an integrated gas pipeline system extending from southwestern Pennsylvania to the New York-Canadian border at the Niagara River and eastward to Ellisburg and Leidy, Pennsylvania, and (ii) 27 underground natural gas storage fields owned and operated by Supply Corporation as well as four other underground natural gas storage fields owned and operated jointly with other interstate gas pipeline companies. Empire, an interstate pipeline company, transports natural gas for Distribution Corporation and for other utilities, large industrial customers and power producers in New York State. Empire owns the Empire Pipeline, 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, and the Empire Connector, which is a 76-mile pipeline extension from near Rochester, New York to an interconnection with the unaffiliated Millennium Pipeline near Corning, New York. The Millennium Pipeline serves the New York City area. The Empire Connector was placed into service on December 10, 2008.

3. The Exploration and Production segment operations are carried out by Seneca Resources Corporation (Seneca), a Pennsylvania corporation. Seneca is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, and in the Gulf Coast region of Texas and Louisiana, including offshore areas in federal waters and some state waters. At September 30, 2009, the Company had U.S. proved developed and undeveloped reserves of 46,587 Mbbl of oil and 248,954 MMcf of natural gas.

In 2007, Seneca sold its subsidiary, Seneca Energy Canada Inc. (SECI), which conducted exploration and production operations in the provinces of Alberta, Saskatchewan and British Columbia in Canada.

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

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 K — Business Segment Information.

The Company's other direct wholly owned subsidiaries are not included in any of the four reported business segments and include the following active companies:

- Highland Forest Resources, Inc. (Highland), a New York corporation which, together with a division of Seneca known as its Northeast Division, markets timber from New York and Pennsylvania land holdings, owns two sawmills in northwestern Pennsylvania and processes timber consisting primarily of high quality hardwoods. At September 30, 2009, the Company owned 103,317 acres of timber property and managed an additional 3,424 acres of timber rights;

- Horizon Energy Development, Inc. (Horizon), a New York corporation formed to engage 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 that is in the process of winding up or selling certain power development projects in Europe. In July 2005, Horizon B.V. sold its entire 85.16% interest in United Energy, a.s., a district heating and electric generation business in the Czech Republic;

- 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;

- Horizon Power, Inc. (Horizon Power), a New York corporation which is an "exempt wholesale generator" under PUHCA 2005 and is developing or operating mid-range independent power production facilities and landfill gas electric generation facilities; and

- National Fuel Gas Midstream Corporation (Midstream Corporation), a Pennsylvania corporation formed to build, own and operate natural gas processing and pipeline gathering facilities in the Appalachian region.

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2009.

Rates and Regulation

The Registrant is a holding company as defined under PUHCA 2005. PUHCA 2005 repealed PUHCA 1935, to which the Company was formerly subject, and granted the FERC and state public utility commissions access to certain books and records of companies in holding company systems. Pursuant to the FERC's regulations under PUHCA 2005, the Company and its subsidiaries are exempt from the FERC's books and records regulations under PUHCA 2005.

The Utility segment's rates, services and other matters are regulated by the NYPSC with respect to services provided within New York and by the 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 and Regulatory Matters" and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note C — Regulatory Matters.

The Pipeline and Storage segment's rates, services and other matters are regulated by the FERC. For additional discussion of the Pipeline and Storage segment's rates and regulation, see Item 7, MD&A under the heading "Rate and Regulatory Matters" and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note C — Regulatory Matters.

The discussion under Item 8 at Note C — 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 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 58.3% of the Company's 2009 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: The Utility Segment" 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 47.0% of the Company's 2009 net income available for common stock.

Supply Corporation has year-to-year or longer service agreements for all of its firm storage capacity, totaling 68,408 MDth. The Utility segment has contracted for 27,865 MDth or 40.7% of the total firm storage capacity, and the Energy Marketing segment accounts for another 4,811 MDth or 7.1% of the total firm storage capacity. Nonaffiliated customers have contracted for the remaining 35,732 MDth or 52.2% of the total firm storage capacity. The majority 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. The contracts also typically include "evergreen" language designed to allow the contracts to extend year-to-year at the end of the primary term. At the beginning of 2010, 82.9% of Supply Corporation's total firm storage capacity was committed under contracts that, subject to 2009 shipper or Supply Corporation notifications, could have been terminated effective in 2010. Supply Corporation did not issue or receive any such storage contract termination notifications in 2009. The strong demand for market-area storage enabled Supply Corporation to provide all of its year-to-year or longer storage services in 2009 at the maximum tariff rates.

Supply Corporation's firm transportation capacity is not a fixed quantity, due to the diverse web-like nature of its pipeline system, and is subject to change as the market identifies different transportation paths and receipt/delivery point combinations. Supply Corporation currently has firm transportation service agreements for approximately 2,189 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,065 MDth per day or 48.7% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 112 MDth per day or 5.1% of contracted transportation capacity. The remaining 1,012 MDth or 46.2% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

At the beginning of 2010, 52.7% of Supply Corporation's contracted transportation capacity was committed under affiliate contracts that were scheduled to expire in 2010 or, subject to 2009 shipper or Supply Corporation notifications, could have been terminated effective in 2010. Based on contract expirations and termination notices received in 2009 for 2010 termination, and taking into account any known contract additions, contracted transportation capacity with affiliates is expected to increase 3.0% in 2010. Similarly, 33.0% of contracted transportation capacity was committed under unaffiliated shipper contracts that were scheduled to expire in 2010 or, subject to 2009 shipper or Supply Corporation notifications, could have been terminated effective in 2010. Based on contract expirations and termination notices received in 2009 for 2010 termination, and taking into account any known contract additions, contracted transportation capacity with unaffiliated shippers is expected to increase 5.3% in 2010. This increase is due largely to the addition of compression at various facilities throughout the system as well as other projects designed to create incremental transportation capacity. Supply Corporation previously has been successful in marketing and obtaining executed contracts for available transportation capacity (at discounted rates when necessary), and expects this success to continue.

For the 2009-2010 winter period, Empire has service agreements in place for firm transportation capacity totaling approximately 689 MDth per day (including capacity on the new Empire Connector facilities discussed below). Most of Empire's firm contracted capacity (93.0%) has been contracted as long-term full-year deals. Two of those contracts are due to expire during 2010, representing just 0.1% of Empire's firm contracted capacity. In addition, Empire has some seasonal (winter-only) contracts that extend for multiple years, representing 2.5% of Empire's firm contracted capacity. One of those seasonal contracts is due to expire during 2010, representing just 0.1% of Empire's firm contracted capacity. Arrangements for the remaining 4.5% of Empire's firm contracted capacity are single-season or single-year contracts that expire during 2010 or early in 2011. Empire expects that all available capacity arising from expiring agreements will be re-contracted as seasonal or full-year agreements. The Utility segment accounts for 6.1% of Empire's firm contracted capacity, and the Energy Marketing segment accounts for 1.2% of Empire's firm contracted capacity, with the remaining 92.7% of Empire's firm contracted capacity subject to contracts with nonaffiliated customers.

Empire's new facilities (the Empire Connector project) were placed into service on December 10, 2008. Empire has a firm service agreement for 150.7 MDth per day of this expansion capacity. This long-term full-year agreement represents approximately 60% of the Empire Connector's total capacity. None of this contracted capacity will expire during fiscal 2010.

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

The Exploration and Production Segment

The Exploration and Production segment incurred a net loss in 2009. The impact of this net loss in relation to the Company's 2009 net income available for common stock was negative 10.2%. The net loss in the Exploration and Production segment was largely driven by an impairment charge of $182.8 million ($108.2 million after tax).

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

The Energy Marketing Segment

The Energy Marketing segment contributed approximately 7.1% of the Company's 2009 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: The Energy Marketing Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

All Other Category and Corporate Operations

The All Other category and Corporate operations incurred a net loss in 2009. The impact of this net loss in relation to the Company's 2009 net income available for common stock was negative 2.2%.

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.

Discontinued Operations

In August 2007, Seneca sold all of the issued and outstanding shares of SECI. SECI's operations are presented in the Company's financial statements as discontinued operations.

Additional discussion of the Company's discontinued operations appears 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 2009, the Utility segment purchased 76.8 Bcf of gas for delivery to its customers. All such purchases were made from non-affiliated companies. Gas purchased from producers and suppliers in the southwestern United States and Canada under firm contracts (seasonal and longer) accounted for 56% of these purchases. Purchases of gas under contracts for one month or less accounted for 44% of the Utility segment's 2009 purchases. Purchases from Total Gas & Power North America Inc. (20%), Chevron Natural Gas (15%), BP Canada (14%) and ConocoPhillips Company (12%) accounted for 61% of the Utility's 2009 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2009.

Supply Corporation transports and stores gas owned by its customers, whose gas originates in the southwestern, mid-continent 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: The Pipeline and Storage Segment" 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 Note K — Business Segment Information and Note Q — Supplementary Information for Oil and Gas Producing Activities.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2009, this segment purchased 62.5 Bcf of gas, including 60.9 Bcf for delivery to its customers. The remaining 1.6 Bcf largely represents gas used in operations. The gas purchased by the Energy Marketing segment originates in either the Appalachian or mid-continent regions of the United States or in Canada.

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 natural gas industry has gone through various stages of regulation. Apart from environmental and state utility commission regulation, the natural gas industry has experienced considerable deregulation. This has enhanced the competitive position of natural gas relative to other energy sources, such as fuel oil or electricity, since some of the historical regulatory impediments to adding customers and responding to market forces have been removed. In addition, management believes that 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 changes in federal law in 1992 and initiatives undertaken by the FERC and various states. It remains unclear what the impact of any further restructuring in response to legislation or other events may be.

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 natural 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. With respect to gas commodity service, in both New York and Pennsylvania, Distribution Corporation has retained a substantial majority of small sales customers. Almost all large-volume load, however, is served by unregulated retail marketers. In New York, approximately 20% of Distribution Corporation's small-volume residential and commercial customers purchase their supplies from unregulated marketers. In Pennsylvania, the PaPUC is currently revising regulations and business practices to promote the growth of small-volume retail competition. Retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation because in both jurisdictions, LDC cost of service is recovered through distribution rates and charges, not through charges for gas commodity service. Over the longer run, however, rate design changes resulting from further customer migration to marketer service (e.g., "unbundling") can expose utility companies such as Distribution Corporation to stranded costs and revenue erosion in the absence of compensating rate relief.

Competition for transportation service to 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 without use of the utility's facilities (i.e., bypass). In addition, competition continues with fuel oil suppliers.

The Utility segment competes in its most vulnerable markets (the large commercial and industrial markets) by offering unbundled, flexible, high quality services. The Utility segment continues to develop or promote new sources and uses of natural gas or new services, rates and contracts.

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. New productive areas in the Appalachian region related to the development of the Marcellus Shale formation, in addition to the aforementioned regions, offer 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 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 noted above, Empire has constructed the Empire Connector project, which expands its natural gas pipeline and enables Empire 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 headings "Investing Cash Flow" and "Rate and Regulatory Matters."

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 originates and acts as operator on certain of its prospects, seeks to minimize the risk of exploratory efforts through partnership-type arrangements, utilizes technology for both exploratory studies and drilling operations, and seeks market niches based on size, operating expertise and financial criteria.

Competition: The Energy Marketing Segment

The Energy Marketing segment competes with other marketers of natural gas and with other providers of energy supply. Competition in this area is well developed with regard to price and services from local, regional and, more recently, national marketers.

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 margins in New York is mitigated by a WNC, which covers the eight-month period from October through May. Weather that is warmer than normal results in an upward adjustment to customers' current bills, while weather that is colder than normal results in a downward adjustment, so that in either case projected operating costs calculated at normal temperatures will be recovered.

Volumes transported and stored by Supply Corporation and volumes transported by Empire may vary materially depending on weather, without materially affecting revenues. Supply Corporation's and Empire'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 to recover only the variable costs associated with actual transportation or storage of gas.

Variations in weather conditions materially affect the volume of gas consumed by customers of the Energy Marketing segment. Volume variations have a corresponding impact on revenues within this segment.

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 "Environmental Matters" and in Item 8, Note I — Commitments and Contingencies.

Miscellaneous

The Company and its wholly owned or majority-owned subsidiaries had a total of 1,949 full-time employees at September 30, 2009. This compares to 1,943 employees in the Company's operations at September 30, 2008.

The Company has agreements in place with collective bargaining units in New York and Pennsylvania. The agreements in New York are scheduled to expire in February 2013 and the agreements in Pennsylvania are scheduled to expire in April 2014 and May 2014.

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, 2009(1)

Name and Age (as of November 15, 2009)	Current Company Positions and Other Material Business Experience During Past Five Years
David F. Smith (56)	Chief Executive Officer of the Company since February 2008 and President of the Company since February 2006. Mr. Smith previously served as Chief Operating Officer of the Company from February 2006 through January 2008; President of Supply Corporation from April 2005 through June 2008; President of Empire from April 2005 through January 2008; Vice President of the Company from April 2005 through January 2006; President of Distribution Corporation from July 1999 to April 2005; and Senior Vice President of Supply Corporation from July 2000 to April 2005.
Ronald J. Tanski (57)	Treasurer and Principal Financial Officer of the Company since April 2004; President of Supply Corporation since July 2008. Mr. Tanski previously served as President of Distribution Corporation from February 2006 through June 2008; Treasurer of Distribution Corporation from April 2004 through September 2008; and Senior Vice President of Distribution Corporation from July 2001 through January 2006.
Matthew D. Cabell (51)	President of Seneca since December 2006. Prior to joining Seneca, Mr. Cabell served as Executive Vice President and General Manager of Marubeni Oil & Gas (USA) Inc., an exploration and production company, from June 2003 to December 2006. Mr. Cabell's prior employer is not a subsidiary or affiliate of the Company.
Anna Marie Cellino (56)	President of Distribution Corporation since July 2008. Ms. Cellino previously served as Secretary of the Company from October 1995 through June 2008; Secretary of Distribution Corporation from September 1999 through September 2008; and Senior Vice President of Distribution Corporation from July 2001 through June 2008.
Karen M. Camiolo (50)	Controller and Principal Accounting Officer of the Company since April 2004; and Controller of Distribution Corporation and Supply Corporation since April 2004.
Carl M. Carlotti (54)	Senior Vice President of Distribution Corporation since January 2008. Mr. Carlotti previously served as Vice President of Distribution Corporation from October 1998 to January 2008.
Paula M. Ciprich (49)	Secretary of the Company since July 2008; General Counsel of the Company since January 2005; Secretary of Distribution Corporation since July 2008. Ms. Ciprich previously served as General Counsel of Distribution Corporation from February 1997 through February 2007 and as Assistant Secretary of Distribution Corporation from February 1997 through June 2008.
Donna L. DeCarolis (50)	Vice President Business Development of the Company since October 2007. Ms. DeCarolis previously served as President of NFR from January 2005 to October 2007; Secretary of NFR from March 2002 to October 2007; and Vice President of NFR from May 2001 to January 2005.
John R. Pustulka (57)	Senior Vice President of Supply Corporation since July 2001.
James D. Ramsdell (54)	Senior Vice President of Distribution Corporation since 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 also have served or currently serve as officers or directors of other subsidiaries of the Company.

Item 1A *Risk Factors*

As a holding company, the Company depends on its operating subsidiaries to meet its financial obligations.

The Company is a holding company with no significant assets other than the stock of its operating subsidiaries. In order to meet its financial needs, the Company relies exclusively on repayments of principal and interest on intercompany loans made by the Company to its operating subsidiaries and income from dividends and other cash flow from the subsidiaries. Such operating subsidiaries may not generate sufficient net income to pay upstream dividends or generate sufficient cash flow to make payments of principal or interest on such intercompany loans.

The Company is dependent on credit markets to successfully execute its business strategies.

The Company relies upon short-term bank borrowings, commercial paper markets and longer-term capital markets to finance capital requirements not satisfied by cash flow from operations. The Company is dependent on these capital sources to provide capital to its subsidiaries to fund operations, acquire, maintain and develop properties, and execute growth strategies. The availability and cost of credit sources may be cyclical and these capital sources may not remain available to the Company. Turmoil in credit markets may make it difficult for the Company to obtain financing on acceptable terms or at all for working capital, capital expenditures and other investments, or to refinance maturing debt on favorable terms. These difficulties could adversely affect the Company's growth strategies, operations and financial performance. The Company's ability to borrow under its credit facilities and commercial paper agreements, and its ability to issue long-term debt under its indentures, depend on the Company's compliance with its obligations under the facilities, agreements and indentures. In addition, the Company's short-term bank loans are in the form of floating rate debt or debt that may have rates fixed for very short periods of time, resulting in exposure to interest rate fluctuations in the absence of interest rate hedging transactions. The cost of long-term debt, the interest rates on the Company's short-term bank loans and the ability of the Company to issue commercial paper are affected by its debt credit ratings published by Standard & Poor's Ratings Service ("S&P"), Moody's Investors Service and Fitch Ratings Service. A downgrade in the Company's credit ratings could increase borrowing costs and negatively impact the availability of capital from banks, commercial paper purchasers and other sources.

The Company may be adversely affected by economic conditions and their impact on our suppliers and customers.

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies. As a consequence, national or regional recessions or other downturns in economic activity could adversely affect the Company's revenues and cash flows or restrict its future growth. Economic conditions in the Company's utility service territories and energy marketing territories also impact its collections of accounts receivable. All of the Company's segments are exposed to risks associated with the creditworthiness or performance of key suppliers and customers, many of which may be adversely affected by volatile conditions in the financial markets. These conditions could result in financial instability or other adverse effects at any of our suppliers or customers. For example, counterparties to the Company's commodity hedging arrangements or commodity sales contracts might not be able to perform their obligations under these arrangements or contracts. Customers of the Company's Utility and Energy Marketing segments may have particular trouble paying their bills during periods of declining economic activity and high commodity prices, potentially resulting in increased bad debt expense and reduced earnings. Any of these events could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

The Company's credit ratings may not reflect all the risks of an investment in its securities.

The Company's credit ratings are an independent assessment of its ability to pay its obligations. Consequently, real or anticipated changes in the Company's credit ratings will generally affect the market value of the specific debt instruments that are rated, as well as the market value of the Company's common stock. The

Company's credit ratings, however, may not reflect the potential impact on the value of its common stock of risks related to structural, market or other factors discussed in this Form 10-K.

The Company's need to comply with comprehensive, complex, and sometimes unpredictable government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.

While the Company generally refers to its Utility segment and its Pipeline and Storage segment as its "regulated segments," there are many governmental regulations that have an impact on almost every aspect of the Company's businesses. Existing statutes and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company, which may affect its business in ways that the Company cannot predict.

In the Company's Utility segment, the operations of Distribution Corporation are subject to the jurisdiction of the NYPSC, the PaPUC and, with respect to certain transactions, the FERC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Distribution Corporation is required in a rate proceeding to reduce the rates it charges its utility customers, or to the extent Distribution Corporation is unable to obtain approval for rate increases from these regulators, particularly when necessary to cover increased costs (including costs that may be incurred in connection with governmental investigations or proceedings or mandated infrastructure inspection, maintenance or replacement programs), earnings may decrease.

In addition to their historical methods of utility regulation, both the PaPUC and NYPSC have sought to establish competitive markets in which customers may purchase gas commodity from unregulated marketers, in addition to utility companies. To date those efforts have been more successful in New York, where approximately 20% of Distribution Corporation's retail sales customers purchase gas commodity from unregulated marketers, than in Pennsylvania, where retail competition remains a fledgling movement. The PaPUC, however, has undertaken recent measures to enhance competition in that state. Retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation, because in both jurisdictions, it recovers its cost of service through distribution rates and charges, and not through any mark-up on the gas commodity purchased by its customers. Over the longer run, however, rate design changes resulting from further customer migration to marketer service ("unbundling") can expose utilities such as Distribution Corporation to stranded costs and revenue erosion in the absence of compensating rate relief.

Both the NYPSC and the PaPUC have instituted proceedings for the purpose of promoting conservation of energy commodities, including natural gas. In New York, Distribution Corporation implemented a Conservation Incentive Program that promotes conservation and efficient use of natural gas by offering customer rebates for high-efficiency appliances, among other things. The intent of conservation and efficiency programs is to reduce customer usage of natural gas. Under traditional volumetric rates, reduced usage by customers results in decreased revenues to the Utility. To prevent revenue erosion caused by conservation, the NYPSC approved a "revenue decoupling mechanism" that renders Distribution Corporation's New York division financially indifferent to the effects of conservation. In Pennsylvania, although a proceeding is pending, the PaPUC has not yet directed Distribution Corporation to implement conservation measures. If the NYPSC were to revoke the revenue decoupling mechanism in a future proceeding or the PaPUC were to adopt a conservation program without a revenue decoupling mechanism or other changes in rate design, reduced customer usage could decrease revenues, forcing Distribution Corporation to file for rate relief.

In New York, aggressive generic statewide programs created under the label of efficiency or conservation continue to generate a sizable utility funding requirement for state agencies that administer those programs. Although utilities are authorized to recover the cost of efficiency and conservation program funding through special rates and surcharges, the resulting upward pressure on customer rates, coupled with increased assessments and taxes, could affect future tolerance for traditional utility rate increases, especially if gas costs were to increase.

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries, including Seneca Resources, Distribution

Corporation and NFR. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their natural gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. State commissions can also petition the FERC to investigate whether Supply Corporation's and Empire's rates are still just and reasonable, and if not, to reduce those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to reduce the rates it charges its natural gas transportation and/or storage customers, or if Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's or Empire's earnings may decrease. The FERC also possesses significant penalty authority with respect to violations of the laws and regulations it administers. Supply Corporation, Empire and, to the extent subject to FERC jurisdiction, the Company's other subsidiaries are subject to the FERC's penalty authority.

The Company's liquidity, and in certain circumstances, its earnings, could be adversely affected by the cost of purchasing natural gas during periods in which natural gas prices are rising significantly.

Tariff rate schedules in each of the Utility segment's service territories contain purchased gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased gas. Assuming those rate adjustments are granted, increases in the cost of purchased gas have no direct impact on profit margins. Nevertheless, increases in the cost of purchased gas affect cash flows and can therefore impact the amount or availability of the Company's capital resources. The Company has issued commercial paper and used short-term borrowings in the past to temporarily finance storage inventories and purchased gas costs, and although the Company expects to do so in the future, it may not be able to access the markets for such borrowings at attractive interest rates or at all. Distribution Corporation is required to file an accounting reconciliation with the regulators in each of the Utility segment's service territories regarding the costs of purchased gas. Due to the nature of the regulatory process, there is a risk of a disallowance of full recovery of these costs during any period in which there has been a substantial upward spike in these costs. Any material disallowance of purchased gas costs could have a material adverse effect on cash flow and earnings. In addition, even when Distribution Corporation is allowed full recovery of these purchased gas costs, during periods when natural gas prices are significantly higher than historical levels, customers may have trouble paying the resulting higher bills, and Distribution Corporation's bad debt expenses may increase and ultimately reduce earnings.

Changes in interest rates may affect the Company's ability to finance capital expenditures and to refinance maturing debt.

The Company's ability to finance capital expenditures and to refinance maturing debt will depend in part upon interest rates. The direction in which interest rates may move is uncertain. Declining interest rates have generally been believed to be favorable to utilities, while rising interest rates are generally believed to be unfavorable, because of the levels of debt that utilities may have outstanding. In addition, the Company's authorized rate of return in its regulated businesses is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, the Company's authorized rate of return could be reduced. If interest rates are higher than assumed rates, the Company's ability to earn its authorized rate of return may be adversely impacted.

Decreased oil and natural gas prices could adversely affect revenues, cash flows and profitability.

The Company's exploration and production operations are materially dependent on prices received for its oil and natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, gathering and processing oil and natural gas. Oil and natural gas prices can be volatile and can be affected by: weather conditions, including natural disasters; the supply and price of foreign oil and natural gas; the level of consumer product demand; national and worldwide economic conditions, including economic disruptions caused by terrorist activities, acts of war or major accidents; political conditions in foreign countries; the price and availability of alternative fuels; the proximity to, and availability of capacity on transportation facilities; regional levels of supply and demand; energy conservation measures; and government regulations, such as regulation of natural gas transportation, royalties, and price controls. The Company sells most of its oil and natural gas at current market prices rather than through fixed-price contracts, although as discussed below, the Company frequently hedges the price of a significant portion of its future production in the financial markets. The prices the Company receives depend upon factors beyond the Company's control, including the factors affecting price mentioned above. The Company believes that any prolonged reduction in oil and natural gas prices would restrict its ability to continue the level of exploration and production activity the Company otherwise would pursue, which could have a material adverse effect on its revenues, cash flows and results of operations.

The Company has significant transactions involving price hedging of its oil and natural gas production as well as its fixed price purchase and sale commitments.

In order to protect itself to some extent against unusual price volatility and to lock in fixed pricing on oil and natural gas production for certain periods of time, the Company regularly enters into commodity price derivatives contracts (hedging arrangements) with respect to a portion of its expected production. These contracts may at any time cover as much as approximately 80% of the Company's expected energy production during the upcoming 12-month period. These contracts reduce exposure to subsequent price drops but can also limit the Company's ability to benefit from increases in commodity prices. In addition, the Energy Marketing segment enters into certain hedging arrangements, primarily with respect to its fixed price purchase and sales commitments and its gas stored underground. The Company's Pipeline and Storage segment enters into hedging arrangements with respect to certain sales of efficiency gas.

Under applicable accounting rules, the Company's hedging arrangements are subject to quarterly effectiveness tests. Inherent within those effectiveness tests are assumptions concerning the long-term price differential between different types of crude oil, assumptions concerning the difference between published natural gas price indexes established by pipelines in which hedged natural gas production is delivered and the reference price established in the hedging arrangements, assumptions regarding the levels of production that will be achieved and, with regard to fixed price commitments, assumptions regarding the creditworthiness of certain customers and their forecasted consumption of natural gas. Depending on market conditions for natural gas and crude oil and the levels of production actually achieved, it is possible that certain of those assumptions may change in the future, and, depending on the magnitude of any such changes, it is possible that a portion of the Company's hedges may no longer be considered highly effective. In that case, gains or losses from the ineffective derivative financial instruments would be marked-to-market on the income statement without regard to an underlying physical transaction. Gains would occur to the extent that natural gas and crude oil hedge prices exceed market prices for the Company's natural gas and crude oil production, and losses would occur to the extent that market prices for the Company's natural gas and crude oil production exceed hedge prices.

Use of energy commodity price hedges also exposes the Company to the risk of non-performance by a contract counterparty. These parties might not be able to perform their obligations under the hedge arrangements.

It is the Company's policy that the use of commodity derivatives contracts comply with various restrictions in effect in respective business segments. For example, in the Exploration and Production segment, commodity derivatives contracts must be confined to the price hedging of existing and forecast production, and in the Energy Marketing segment, commodity derivatives with respect to fixed price purchase and sales commitments must be matched against commitments reasonably certain to be fulfilled. Similar restrictions apply in the Pipeline and Storage segment. The Company maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades, if they were to occur, could expose the Company to substantial losses to cover positions in its derivatives contracts. In addition, in the event the Company's actual production of oil and natural gas falls short of hedged forecast production, the Company may incur substantial losses to cover its hedges.

You should not place undue reliance on reserve information because such information represents estimates.

This Form 10-K contains estimates of the Company's proved oil and natural gas reserves and the future net cash flows from those reserves that were prepared by the Company's petroleum engineers and audited by independent petroleum engineers. Petroleum engineers consider many factors and make assumptions in estimating oil and natural gas reserves and future net cash flows. These factors include: historical production from the area compared with production from other producing areas; the assumed effect of governmental regulation; and assumptions concerning oil and natural gas prices, production and development costs, severance and excise taxes, and capital expenditures. Lower oil and natural gas prices generally cause estimates of proved reserves to be lower. Estimates of reserves and expected future cash flows prepared by different engineers, or by the same engineers at different times, may differ substantially. Ultimately, actual production, revenues and expenditures relating to the Company's reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of the Company's reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

If conditions remain constant, then the Company is reasonably certain that its reserve estimates represent economically recoverable oil and natural gas reserves and future net cash flows. If conditions change in the future, then subsequent reserve estimates may be revised accordingly. You should not assume that the present value of future net cash flows from the Company's proved reserves is the current market value of the Company's estimated oil and natural gas reserves. In accordance with SEC requirements, the Company bases the estimated discounted future net cash flows from its proved reserves on prices and costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. Any significant price changes will have a material effect on the present value of the Company's reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of natural gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to the Company's reserve estimates in the future. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including historical production from the area compared with production from other comparable producing areas, and the assumed effects of regulations by governmental agencies. Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves: the quantities of oil and natural gas that are ultimately recovered, the timing of the recovery of oil and natural gas reserves, the production and operating costs incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

The amount and timing of actual future oil and natural gas production and the cost of drilling are difficult to predict and may vary significantly from reserves and production estimates, which may reduce the Company's earnings.

There are many risks in developing oil and natural gas, including numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures. The future success of the Company's Exploration and Production segment depends on its ability to develop additional oil and natural gas reserves that are economically recoverable, and its failure to do so may reduce the Company's earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. The Company's drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, geology, and other factors. Drilling for oil and natural gas can be unprofitable, not only from non-productive wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements, including completion of environmental impact analyses and compliance with other environmental laws and regulations, and shortages or delays in the delivery of equipment and services can delay drilling operations or result in their cancellation. The cost of drilling, completing, and operating wells is often uncertain, and new wells may not be productive or the Company may not recover all or any portion of its investment. Without continued successful exploitation or acquisition activities, the Company's reserves and revenues will decline as a result of its current reserves being depleted by production. The Company cannot assure you that it will be able to find or acquire additional reserves at acceptable costs.

Financial accounting requirements regarding exploration and production activities may affect the Company's profitability.

The Company accounts for its exploration and production activities under the full cost method of accounting. Each quarter, the Company must compare the level of its unamortized investment in oil and natural gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses quarter-end spot prices for oil and natural gas (as adjusted for hedging). If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. The Company's Exploration and Production segment recorded an impairment charge under the full cost method of accounting in the quarter ended December 31, 2008. If spot market prices at a subsequent quarter end are lower than prices at December 31, 2008, absent any changes in other factors affecting the present value of the future net revenue projected to be recovered from the Company's oil and natural gas properties, the Company would be required to record an additional impairment charge. Depending on the magnitude of the decrease in prices, that charge could be material.

Environmental regulation significantly affects the Company's business.

The Company's business operations are subject to federal, state, and local laws and regulations relating to environmental protection. These laws and regulations concern the generation, storage, transportation, disposal or discharge of contaminants and greenhouse gases into the environment, the reporting of such matters, and the general protection of public health, natural resources, wildlife and the environment. Costs of compliance and liabilities could negatively affect the Company's results of operations, financial condition and cash flows. In addition, compliance with environmental laws and regulations could require unexpected capital expenditures at the Company's facilities or delay or cause the cancellation of expansion projects or oil and natural gas drilling activities. Because the costs of complying with environmental regulations are significant, additional regulation could negatively affect the Company's business. Although the Company cannot predict the impact of the interpretation or enforcement of EPA standards or other federal, state and local regulations, the Company's costs could increase if environmental laws and regulations become more strict.

The nature of the Company's operations presents inherent risks of loss that could adversely affect its results of operations, financial condition and cash flows.

The Company's operations in its various segments are subject to inherent hazards and risks such as: fires; natural disasters; explosions; geological formations with abnormal pressures; blowouts during well drilling; collapses of wellbore casing or other tubulars; pipeline ruptures; spills; and other hazards and risks that may cause personal injury, death, property damage, environmental damage or business interruption losses. Additionally, the Company's facilities, machinery, and equipment may be subject to sabotage. Any of these events could cause a loss of hydrocarbons, environmental pollution, claims for personal injury, death, property damage or business interruption, or governmental investigations, recommendations, claims, fines or penalties. As protection against operational hazards, the Company maintains insurance coverage against some, but not all, potential losses. In addition, many of the agreements that the Company executes with contractors provide for the division of responsibilities between the contractor and the Company, and the Company seeks to obtain an indemnification from the contractor for certain of these risks. The Company is not always able, however, to secure written agreements with its contractors that contain indemnification, and sometimes the Company is required to indemnify others.

Insurance or indemnification agreements when obtained may not adequately protect the Company against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, the imposition of fines, penalties or mandated programs by governmental authorities, the failure of a contractor to meet its indemnification obligations, or the failure of an insurance company to pay valid claims could result in substantial losses to the Company. In addition, insurance may not be available, or if available may not be adequate, to cover any or all of these risks. It is also possible that insurance premiums or other costs may rise significantly in the future, so as to make such insurance prohibitively expensive.

Due to the significant cost of insurance coverage for named windstorms in the Gulf of Mexico, the Company determined that it was not economical to purchase insurance to fully cover its exposures related to such storms. It is possible that named windstorms in the Gulf of Mexico could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

Hazards and risks faced by the Company, and insurance and indemnification obtained or provided by the Company, may subject the Company to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines or penalties against the Company or be resolved on unfavorable terms, the result of which could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

The increasing costs of certain employee and retiree benefits could adversely affect the Company's results.

The Company's earnings and cash flow may be impacted by the amount of income or expense it expends or records for employee benefit plans. This is particularly true for pension plans, which are dependent on actual plan asset returns and factors used to determine the value and current costs of plan benefit obligations. In addition, if medical costs rise at a rate faster than the general inflation rate, the Company might not be able to mitigate the rising costs of medical benefits. Increases to the costs of pension and medical benefits could have an adverse effect on the Company's financial results.

Significant shareholders or potential shareholders may attempt to effect changes at the Company or acquire control over the Company, which could adversely affect the Company's results of operations and financial condition.

In January 2008, the Company entered into an agreement with New Mountain Vantage GP, L.L.C. ("New Mountain") and certain parties related to New Mountain, including the California Public Employees' Retirement System (collectively, "Vantage"), to settle a proxy contest pertaining to the election of directors to the Company's Board of Directors at the Company's 2008 Annual Meeting of Stockholders. That settlement agreement expired on September 15, 2009. Vantage or other existing or potential shareholders may engage in proxy solicitations or advance shareholder proposals after the Company's 2010 Annual Meeting of Stockholders, or otherwise attempt to effect changes or acquire control over the Company.

Campaigns by shareholders to effect changes at publicly traded companies are sometimes led by investors seeking to increase short-term shareholder value through actions such as financial restructuring, increased debt, special dividends, stock repurchases or sales of assets or the entire company. Responding to proxy contests and other actions by activist shareholders can be costly and time-consuming, disrupting the Company's operations and diverting the attention of the Company's Board of Directors and senior management from the pursuit of business strategies. As a result, shareholder campaigns could adversely affect the Company's results of operations and financial condition.

Item 1B *Unresolved Staff Comments*

None

Item 2 *Properties*

General Information on Facilities

The net investment of the Company in property, plant and equipment was $3.1 billion at September 30, 2009. Approximately 63% 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 (33%), is primarily located in California, in the Appalachian region of the United States, and in the Gulf Coast region of Texas and Louisiana. The remaining net investment in property, plant and equipment consisted of the All Other and Corporate operations (4%). During the past five years, the Company has made additions to property, plant and equipment in order to expand and improve transmission and distribution facilities for both retail and transportation customers. Net property, plant and equipment has increased $125.3 million, or 4.2%, since 2004. During 2007, the Company sold SECI, Seneca's wholly owned subsidiary that operated in Canada. The net property, plant and equipment of SECI at the date of sale was $107.7 million. In addition, during 2005, the Company sold its majority interest in U.E., a district heating and electric generation business in the Czech Republic. The net property, plant and equipment of U.E. at the date of sale was $223.9 million.

The Utility segment had a net investment in property, plant and equipment of $1.1 billion at September 30, 2009. The net investment in its gas distribution network (including 14,837 miles of distribution pipeline) and its service connections to customers represent approximately 52% and 34%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2009.

The Pipeline and Storage segment had a net investment of $839.4 million in property, plant and equipment at September 30, 2009. Transmission pipeline represents 43% of this segment's total net investment and includes 2,364 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 20% of this segment's total net investment and consist of 31 storage fields, four of which are jointly owned and operated with certain pipeline suppliers, and 428 miles of pipeline. Net investment in storage facilities includes $89.7 million of gas stored underground-noncurrent, representing the cost of the gas utilized 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 28 compressor stations with 95,949 installed compressor horsepower that represent 10% of this segment's total net investment in property, plant and equipment.

The Exploration and Production segment had a net investment in property, plant and equipment of $1.0 billion at September 30, 2009.

The Utility and Pipeline and Storage segments' facilities provided the capacity to meet the Company's 2009 peak day sendout, including transportation service, of 1,733 MMcf, which occurred on January 15, 2009. Withdrawals from storage of 694.1 MMcf provided approximately 40.1% of the requirements on that day.

Company maps are included in exhibit 99.2 of this Form 10-K and are incorporated herein by reference.

Exploration and Production Activities

The Company is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, and in the Gulf Coast region of Texas and Louisiana. Also, Exploration and Production operations were conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada, until the sale of these properties on August 31, 2007. Further discussion of the sale of the Canadian oil and gas properties is included in Item 8, Note J — Discontinued Operations. Further discussion of oil and gas producing activities is included in Item 8, Note Q — Supplementary Information for Oil and Gas Producing Activities. Note Q sets forth proved developed and undeveloped reserve information for Seneca.

Seneca's proved developed and undeveloped natural gas reserves increased from 226 Bcf at September 30, 2008 to 249 Bcf at September 30, 2009. This increase is attributed primarily to extensions and discoveries (59.2 Bcf), primarily in the Appalachian region (49.2 Bcf). This increase was partially offset by production of

22.3 Bcf, negative revisions of previous estimates (9.6 Bcf) and sales of minerals in place (4.7 Bcf) in the Gulf Coast region. Seneca's proved developed and undeveloped oil reserves increased from 46,198 Mbbl at September 30, 2008 to 46,587 Mbbl at September 30, 2009. This increase is attributed to purchases of minerals in place (2,115 Mbbl) in the West Coast region, extensions and discoveries (1,213 Mbbl), and revisions of previous estimates (449 Mbbl). These increases were largely offset by production (3,373 Mbbl), primarily occurring in the West Coast region (2,674 Mbbl). On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 503 Bcfe at September 30, 2008 to 528 Bcfe at September 30, 2009.

Seneca's proved developed and undeveloped natural gas reserves increased from 205 Bcf at September 30, 2007 to 226 Bcf at September 30, 2008. This increase is attributed primarily to extensions and discoveries (40.1 Bcf), primarily in the Appalachian region (31.3 Bcf). This increase was partially offset by production of 22.3 Bcf. Seneca's proved developed and undeveloped oil reserves decreased from 47,586 Mbbl at September 30, 2007 to 46,198 Mbbl at September 30, 2008. This decrease is attributed to production (3,070 Mbbl), primarily occurring in the West Coast region (2,460 Mbbl) and sales of minerals in place (1,334 Mbbl). These decreases were partially offset by purchases of minerals in place (2,084 Mbbl) and extensions and discoveries (827 Mbbl). On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 491 Bcfe at September 30, 2007 to 503 Bcfe at September 30, 2008.

Seneca's oil and gas reserves reported in Item 8 at Note Q as of September 30, 2009 were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Netherland, Sewell & 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 oil and gas reserve information reported to the EIA showed 227 Bcf and 47,630 Mbbl of gas and oil reserves, respectively, which differs from the reserve information summarized in Item 8 at Note Q. The reasons for this difference are as follows: (a) reserves are reported to the EIA on a calendar year basis, while reserves disclosed in Item 8 at Note Q are shown on a fiscal year basis; (b) reserves reported to the EIA include only properties operated by Seneca, while reserves disclosed in Item 8 at Note Q included both Seneca operated properties and non-operated properties in which Seneca has an interest; and (c) reserves are reported to the EIA on a gross basis versus the reserves disclosed in Item 8 at Note Q, which are reported on a net revenue interest basis.

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		
	2009	**2008**	**2007**
United States			
Gulf Coast Region			
Average Sales Price per Mcf of Gas	$ 4.54	$ 10.03	$ 6.58
Average Sales Price per Barrel of Oil	$54.58	$107.27	$63.04
Average Sales Price per Mcf of Gas (after hedging)	$ 5.28	$ 9.49	$ 6.87
Average Sales Price per Barrel of Oil (after hedging)	$54.58	$ 98.56	$64.09
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.53	$ 1.63	$ 1.08
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	38	38	40
West Coast Region			
Average Sales Price per Mcf of Gas	$ 3.91	$ 8.71	$ 6.54
Average Sales Price per Barrel of Oil	$50.90	$ 98.17	$56.86
Average Sales Price per Mcf of Gas (after hedging)	$ 7.37	$ 8.22	$ 6.82
Average Sales Price per Barrel of Oil (after hedging)	$67.61	$ 77.64	$47.43

	For The Year Ended September 30		
	2009	2008	2007
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.68	$ 2.01	$ 1.54
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	55	51	50
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 5.52	$ 9.73	$ 7.48
Average Sales Price per Barrel of Oil	$56.15	$ 97.40	$62.26
Average Sales Price per Mcf of Gas (after hedging)	$ 8.69	$ 8.85	$ 8.25
Average Sales Price per Barrel of Oil (after hedging)	$56.15	$ 97.40	$62.26
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.89	$ 0.77	$ 0.69
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	24	22	17
Total United States			
Average Sales Price per Mcf of Gas	$ 4.79	$ 9.70	$ 6.82
Average Sales Price per Barrel of Oil	$51.69	$ 99.64	$58.43
Average Sales Price per Mcf of Gas (after hedging)	$ 6.94	$ 9.05	$ 7.25
Average Sales Price per Barrel of Oil (after hedging)	$64.94	$ 81.75	$51.68
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.47	$ 1.64	$ 1.23
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	116	111	108
Canada — Discontinued Operations			
Average Sales Price per Mcf of Gas	$ —	$ —	$ 6.09
Average Sales Price per Barrel of Oil	$ —	$ —	$50.06
Average Sales Price per Mcf of Gas (after hedging)	$ —	$ —	$ 6.17
Average Sales Price per Barrel of Oil (after hedging)	$ —	$ —	$50.06
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ —	$ —	$ 1.94
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	—	—	21
Total Company			
Average Sales Price per Mcf of Gas	$ 4.79	$ 9.70	$ 6.64
Average Sales Price per Barrel of Oil	$51.69	$ 99.64	$57.93
Average Sales Price per Mcf of Gas (after hedging)	$ 6.94	$ 9.05	$ 6.98
Average Sales Price per Barrel of Oil (after hedging)	$64.94	$ 81.75	$51.58
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.47	$ 1.64	$ 1.35
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	116	111	129

Productive Wells

At September 30, 2009	Gulf Coast Region Gas	Gulf Coast Region Oil	West Coast Region Gas	West Coast Region Oil	Appalachian Region Gas	Appalachian Region Oil	Total Company Gas	Total Company Oil
Productive Wells — Gross	20	42	—	1,510	2,848	6	2,868	1,558
Productive Wells — Net	12	14	—	1,484	2,766	5	2,778	1,503

Developed and Undeveloped Acreage

At September 30, 2009	Gulf Coast Region	West Coast Region	Appalachian Region	Total Company
Developed Acreage				
— Gross	113,934	15,118	532,872	661,924
— Net	80,852	12,926	504,783	598,561
Undeveloped Acreage				
— Gross	142,118	19,002	458,182	619,302
— Net	102,831	10,177	437,408	550,416
Total Developed and Undeveloped Acreage				
— Gross	256,052	34,120	991,054	1,281,226
— Net	183,683	23,103	942,191	1,148,977

As of September 30, 2009, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 34,887 acres in 2010 (16,764 net acres), 90,456 acres in 2011 (70,162 net acres), 22,222 acres in 2012 (20,532 net acres), and 471,737 acres thereafter (442,958 net acres).

Drilling Activity

For the Year Ended September 30	Productive 2009	Productive 2008	Productive 2007	Dry 2009	Dry 2008	Dry 2007
United States						
Gulf Coast Region						
Net Wells Completed						
— Exploratory	0.29	1.14	1.31	—	0.37	1.42
— Development	—	—	1.00	0.30	—	0.67
West Coast Region						
Net Wells Completed						
— Exploratory	—	1.00	0.50	—	—	—
— Development	27.00	62.00	58.99	—	1.00	2.00
Appalachian Region						
Net Wells Completed						
— Exploratory	2.00	8.00	8.10	3.00	1.00	—
— Development	250.00	186.00	184.00	—	—	2.00
Total United States						
Net Wells Completed						
— Exploratory	2.29	10.14	9.91	3.00	1.37	1.42
— Development	277.00	248.00	243.99	0.30	1.00	4.67
Canada — Discontinued Operations						
Net Wells Completed						
— Exploratory	—	—	6.38	—	—	—
— Development	—	—	1.80	—	—	—
Total						
Net Wells Completed						
— Exploratory	2.29	10.14	16.29	3.00	1.37	1.42
— Development	277.00	248.00	245.79	0.30	1.00	4.67

Present Activities

At September 30, 2009	Gulf Coast Region	West Coast Region	Appalachian Region	Total Company
Wells in Process of Drilling(1)				
— Gross	—	—	118.00	118.00
— Net	—	—	108.50	108.50

(1) Includes wells awaiting completion.

Item 3 *Legal Proceedings*

For a discussion of various environmental and other matters, refer to Part II, Item 7, MD&A and Item 8 at Note I — Commitments and Contingencies. In addition to these matters, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service, and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to 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, 2009.

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 E — Capitalization and Short-Term Borrowings and Note P — Market for Common Stock and Related Shareholder Matters (unaudited).

On July 1, 2009, the Company issued a total of 2,800 unregistered shares of Company common stock to the seven non-employee directors of the Company then serving on the Board of Directors of the Company and receiving compensation under the Company's Retainer Policy for Non-Employee Directors, 400 shares to each such director. On September 30, 2009, the Company issued 65 unregistered shares of Company common stock to Frederic V. Salerno, a non-employee director of the Company, under the Company's Retainer Policy for Non-Employee Directors. All of these unregistered shares were issued as partial consideration for such directors' services during the quarter ended September 30, 2009. 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(b)
July 1-31, 2009	9,709	$37.77	—	6,971,019
Aug. 1-31, 2009	10,919	$44.52	—	6,971,019
Sept. 1-30, 2009	8,269	$45.98	—	6,971,019
Total	28,897	$42.67	—	6,971,019

(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 or applicable withholding taxes. During the quarter ended September 30, 2009, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 28,897 shares purchased other than through a publicly announced share repurchase program, 26,682 were purchased for the Company's 401(k) plans and 2,215 were purchased as a result of shares tendered to the Company by holders of stock options or shares of restricted stock.

(b) In December 2005, the Company's Board of Directors authorized the repurchase of up to eight million shares of the Company's common stock. The Company completed the repurchase of the eight million shares during 2008. In September 2008, the Company's Board of Directors authorized the repurchase of an additional eight million shares of the Company's common stock. The Company, however, stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. However, such repurchases may be made in the future, either in the open market or through private transactions.

Item 6 *Selected Financial Data*

	Year Ended September 30 2009	2008	2007 (Thousands)	2006	2005
Summary of Operations					
Operating Revenues	$2,057,852	$2,400,361	$2,039,566	$2,239,675	$1,860,774
Operating Expenses:					
Purchased Gas	1,001,782	1,235,157	1,018,081	1,267,562	959,827
Operation and Maintenance	402,856	432,871	396,408	395,289	388,094
Property, Franchise and Other Taxes	72,163	75,585	70,660	69,202	68,164
Depreciation, Depletion and Amortization	173,410	170,623	157,919	151,999	156,502
Impairment of Oil and Gas Producing Properties	182,811	—	—	—	—
	1,833,022	1,914,236	1,643,068	1,884,052	1,572,587
Operating Income	224,830	486,125	396,498	355,623	288,187
Other Income (Expense):					
Income from Unconsolidated Subsidiaries	3,366	6,303	4,979	3,583	3,362
Impairment of Investment in Partnership	(1,804)	—	—	—	(4,158)
Other Income	6,576	7,376	4,936	2,825	12,744
Interest Income	5,776	10,815	1,550	9,409	6,236
Interest Expense on Long-Term Debt	(79,419)	(70,099)	(68,446)	(72,629)	(73,244)
Other Interest Expense	(7,497)	(3,870)	(6,029)	(5,952)	(9,069)
Income from Continuing Operations Before Income Taxes	151,828	436,650	333,488	292,859	224,058
Income Tax Expense	51,120	167,922	131,813	108,245	85,621
Income from Continuing Operations	100,708	268,728	201,675	184,614	138,437
Discontinued Operations:					
Income (Loss) from Operations, Net of Tax	—	—	15,479	(46,523)	25,277
Gain on Disposal, Net of Tax	—	—	120,301	—	25,774
Income (Loss) from Discontinued Operations, Net of Tax	—	—	135,780	(46,523)	51,051
Net Income Available for Common Stock	$ 100,708	$ 268,728	$ 337,455	$ 138,091	$ 189,488

	Year Ended September 30				
	2009	2008	2007	2006	2005
			(Thousands)		
Per Common Share Data					
Basic Earnings from Continuing Operations per Common Share	$ 1.26	$ 3.27	$ 2.43	$ 2.20	$ 1.66
Diluted Earnings from Continuing Operations per Common Share	$ 1.25	$ 3.18	$ 2.37	$ 2.15	$ 1.63
Basic Earnings per Common Share(1)	$ 1.26	$ 3.27	$ 4.06	$ 1.64	$ 2.27
Diluted Earnings per Common Share(1)	$ 1.25	$ 3.18	$ 3.96	$ 1.61	$ 2.23
Dividends Declared	$ 1.32	$ 1.27	$ 1.22	$ 1.18	$ 1.14
Dividends Paid	$ 1.31	$ 1.26	$ 1.21	$ 1.17	$ 1.13
Dividend Rate at Year-End	$ 1.34	$ 1.30	$ 1.24	$ 1.20	$ 1.16
At September 30:					
Number of Registered Shareholders	16,098	16,544	16,989	17,767	18,369
Net Property, Plant and Equipment					
Utility	$1,144,002	$1,125,859	$1,099,280	$1,084,080	$1,064,588
Pipeline and Storage	839,424	826,528	681,940	674,175	680,574
Exploration and Production(2)	1,041,846	1,095,960	982,698	1,002,265	974,806
Energy Marketing	71	98	102	59	97
All Other	99,787	98,338	106,637	108,333	112,924
Corporate	6,915	7,317	7,748	8,814	6,311
Total Net Plant	$3,132,045	$3,154,100	$2,878,405	$2,877,726	$2,839,300
Total Assets	$4,769,129	$4,130,187	$3,888,412	$3,763,748	$3,749,753
Capitalization					
Comprehensive Shareholders' Equity	$1,589,236	$1,603,599	$1,630,119	$1,443,562	$1,229,583
Long-Term Debt, Net of Current Portion	1,249,000	999,000	799,000	1,095,675	1,119,012
Total Capitalization	$2,838,236	$2,602,599	$2,429,119	$2,539,237	$2,348,595

(1) Includes discontinued operations.

(2) Includes net plant of SECI discontinued operations as follows: $0 for 2009, 2008 and 2007, $88,023 for 2006, and $170,929 for 2005.

Item 7 *Management's Discussion and Analysis of Financial Condition and Results of Operations*

OVERVIEW

The Company is a diversified energy company and reports financial results for four business segments. Refer to Item 1, Business, for a more detailed description of each of the segments. This Item 7, MD&A, provides information concerning:

1. The critical accounting estimates 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) 2009 and projected 2010 funding for the Company's pension and other post-retirement benefits, (b) realizability of deferred tax assets (c) disclosures and tables concerning market risk sensitive instruments, (d) rate and regulatory matters in the Company's New York, Pennsylvania and FERC regulated jurisdictions, (e) environmental matters, and (f) new authoritative accounting and financial reporting guidance.

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

For the year ended September 30, 2009 compared to the year ended September 30, 2008, the Company experienced a decrease in earnings of $168.0 million, primarily due to lower earnings in the Exploration and Production segment. The earnings decrease was driven largely by an impairment charge of $182.8 million ($108.2 million after tax) recorded in the Exploration and Production segment, along with reduced crude oil and natural gas prices. 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. Such costs are subject to a quarterly ceiling test prescribed by SEC Regulation S-X Rule 4-10 that determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. At December 31, 2008, due to significant declines in crude oil and natural gas commodity prices (Cushing, Oklahoma West Texas Intermediate oil reported spot price of $44.60 per Bbl at December 31, 2008 versus a reported price of $100.70 per Bbl at September 30, 2008; Henry Hub natural gas reported spot price of $5.63 per MMBtu at December 31, 2008 versus a reported price of $7.12 per MMBtu at September 30, 2008), the book value of the Company's oil and gas properties exceeded the ceiling, resulting in the impairment charge mentioned above. (Note — Because actual pricing of the Company's various producing properties varies depending on their location, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Cushing oil and Henry Hub prices, which are only indicative of current prices.) At September 30, 2009, the quoted Cushing, Oklahoma spot price for West Texas Intermediate oil was $70.46 per Bbl ($69.82 per Bbl at June 30, 2009 and $49.64 per Bbl at March 31, 2009) and the quoted spot price for natural gas was $3.30 per MMBtu ($3.88 per MMBtu at June 30, 2009 and $3.63 per MMBtu at March 31, 2009). At September 30, 2009, the ceiling exceeded the book value of the Company's oil and gas properties by approximately $212 million (and approximately $247 million and $37 million at June 30, 2009 and March 31, 2009, respectively). If natural gas prices used in the ceiling test calculation at September 30, 2009 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $165 million. If crude oil prices used in the ceiling test calculation at September 30, 2009 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $160 million. If both natural gas and crude oil prices used in the ceiling test calculation at September 30, 2009 were lower by $1 per MMBtu and $5 per Bbl, respectively, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $113 million. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation.

Despite the decrease in earnings discussed above, the Company's balance sheet consisted of a capitalization structure of 56% equity and 44% debt at September 30, 2009. With its April 2009 issuance of $250.0 million of 8.75% notes due in May 2019, management believes that it has enhanced its liquidity position at a time when there is still uncertainty in the credit markets. At September 30, 2009, the Company did not have any short-term borrowings outstanding. However, the Company continues to maintain a number of individual uncommitted or discretionary lines of credit with financial institutions for general corporate purposes. These credit lines, which aggregate to $420.0 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, or replaced by similar lines. The total amount available to be issued under the Company's commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million, which commitment extends through September 30, 2010.

The Company's liquidity position will become increasingly important over the next three years. The Company anticipates spending $413 million for capital expenditures in 2010. In addition, the Company has identified possible additional projects where capital expenditures could amount to $723 million in 2011 and $816 million in 2012. The majority of these expenditures have been targeted for the Exploration and Production segment, where the Company anticipates spending $255 million in 2010 ($224 million in Appalachia). Depending on drilling success in 2010, commodity pricing, and, subject to approval of the Company's Board of Directors, spending could reach $417 million in 2011 ($385 million in Appalachia), and $497 million in 2012 ($444 million in Appalachia). The significant rise in estimated capital expenditures in the Exploration and Production segment, specifically in the Appalachian region, can be attributed to a strong emphasis on developing natural gas properties in the Marcellus Shale. The emphasis on Marcellus Shale development will carry over into the Pipeline and Storage segment, which is anticipating the need for additional pipeline and storage capacity as Marcellus Shale production comes on line. Pipeline and Storage segment capital expenditures are anticipated to be $51 million in 2010, with opportunities to spend up to $227 million in 2011 and $240 million in 2012, depending on market acceptance of the proposed projects, contractual commitments from shippers, and approval from the Company's Board of Directors. The projects being considered in the Pipeline and Storage segment are discussed in detail in the Investing Cash Flow section of the Capital Resources and Liquidity section that follows. The Company anticipates financing these capital expenditures with cash from operations, short-term borrowings and long-term debt.

CRITICAL ACCOUNTING ESTIMATES

The Company has prepared its consolidated financial statements in conformity with GAAP. 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 estimates, which are defined as those estimates whereby judgments or uncertainties could affect the application of accounting 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 does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

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). Unproved properties are excluded from the depletion calculation until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

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 , which is performed each quarter, determines a limit, or ceiling, on 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 cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, 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 tax effects related to the differences between the book and tax basis of the properties. 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 to or subtractions from 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. At September 30, 2008, the ceiling exceeded the book value of the Company's oil and gas properties by approximately $500 million. Because of declines in commodity prices subsequent to September 30, 2008, the book value of the Company's oil and gas properties exceeded the ceiling at December 31, 2008. The quoted Cushing, Oklahoma spot price for West Texas Intermediate oil had declined from a reported price of $100.70 per Bbl at September 30, 2008 to a reported price of $44.60 per Bbl at December 31, 2008. The quoted Henry Hub spot price for natural gas had declined from a reported price of $7.12 per MMBtu at September 30, 2008 to a reported price of $5.63 per MMBtu at December 31, 2008. Consequently, the Company recorded an impairment charge of $182.8 million ($108.2 million after-tax) during the quarter ended December 31, 2008. (Note — Because actual pricing of the Company's various producing properties varies depending on their location, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Cushing oil and Henry Hub prices, which are only indicative of current prices.) At September 30, 2009, the quoted Cushing, Oklahoma spot price for West Texas Intermediate oil was $70.46 per Bbl ($69.82 per Bbl at June 30, 2009 and $49.64 per Bbl at March 31, 2009) and the quoted spot price for natural gas was $3.30 per MMBtu ($3.88 per MMBtu at June 30, 2009 and $3.63 per MMBtu at March 31, 2009). At September 30, 2009, the ceiling exceeded the book value of the Company's oil and gas properties by approximately $212 million (and approximately $247 million and $37 million at June 30, 2009 and March 31, 2009, respectively). If natural gas prices used in the ceiling test calculation at September 30, 2009 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $165 million. If crude oil prices used in the ceiling test calculation at September 30, 2009 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $160 million. If both natural gas and crude oil prices used in the ceiling test calculation at September 30, 2009 were lower by $1 per MMBtu and $5 per Bbl, respectively, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $113 million. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation.

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

In accordance with the current authoritative guidance for asset retirement obligations, the Company records an asset retirement obligation for plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and capitalizes such costs in property, plant and equipment (i.e. the full cost pool). Under the current authoritative guidance for asset retirement obligations, since plugging and abandonment costs are already included in the full cost pool, the units-of-production depletion calculation excludes from the depletion base any estimate of future plugging and abandonment costs that are already recorded in the full cost pool.

As discussed above, the full cost method of accounting provides a ceiling to the amount of costs that can be capitalized in the full cost pool. In accordance with current authoritative guidance, since the full cost pool includes an amount associated with plugging and abandoning the wells, as discussed in the preceding paragraph, the calculation of the full cost ceiling no longer reduces the future net cash flows from proved oil and gas reserves by an estimate of plugging and abandonment costs.

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 the FASB authoritative guidance regarding accounting for certain types of regulations, 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 C — Regulatory Matters.

Accounting for Derivative Financial Instruments. The Company, in its Exploration and Production segment, Energy Marketing segment, and Pipeline and Storage segment, 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 and futures contracts. The Company, in its Pipeline and Storage segment, previously used an interest rate collar to limit interest rate fluctuations on certain variable rate debt. In accordance with the authoritative guidance for derivative instruments and hedging activities, the Company accounted for these instruments as effective cash flow hedges or fair value hedges. In 2007, the Company discontinued hedge accounting for the interest rate collar, which resulted in a gain being recognized. 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 based on the effectiveness testing, mark-to-market gains or losses from the derivative financial instruments would be recognized in the income statement without regard to an underlying physical transaction.

The Company uses both exchange-traded and non exchange-traded derivative financial instruments. The Company adopted the authoritative guidance for fair value measurements during the quarter ended December 31, 2008. As such, the fair value of such derivative financial instruments is determined under the provisions of this guidance. The fair value of exchange traded derivative financial instruments is determined from Level 1 inputs, which are quoted prices in active markets. The Company determines the fair value of non exchange-traded derivative financial instruments based on an internal model, which uses both observable and unobservable inputs other than quoted prices. These inputs are considered Level 2 or Level 3 inputs. All derivative financial instrument assets and liabilities are evaluated for the probability of default by either the counterparty or the Company. Credit reserves are applied against the fair values of such assets or liabilities. Refer to the "Market Risk Sensitive Instruments" section below 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. The Company utilizes a yield curve model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments. The expected return on plan assets assumption used by the Company 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. Changes in actuarial assumptions and actuarial experience, including deviations between actual versus expected return on plan assets, 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." Pension and post-retirement benefit costs for the Utility and Pipeline and Storage segments, as determined under the authoritative guidance for pensions and postretirement benefits, represented 90% of the Company's total pension and post-retirement benefit costs for the years ended September 30, 2009 and 2008.

Changes in actuarial assumptions and actuarial experience could also have an impact on the benefit obligation and the funded status related to the Company's pension and other post-retirement benefits and could impact the Company's equity. For example, the discount rate was changed from 6.75% in 2008 to 5.50% in 2009. The change in the discount rate from 2008 to 2009 increased the Retirement Plan projected benefit obligation by \$102.6 million and the accumulated post-retirement benefit obligation by \$60.9 million. Other examples include actual versus expected return on plan assets, which has an impact on the funded status of the plans, and actual versus expected benefit payments, which has an impact on the pension plan projected benefit obligation and the accumulated post-retirement benefit obligation. For 2009, actual versus expected return on plan assets resulted in a decrease to the funded status of the Retirement Plan (\$157.5 million) and the VEBA trusts and 401(h) accounts (\$94.0 million). The actual versus expected benefit payments for 2009 caused a decrease of \$2.2 million to the accumulated post-retirement benefit obligation. In calculating the projected benefit obligation for the Retirement Plan and the accumulated post-retirement obligation, the actuary takes into account the average remaining service life of active participants. The average remaining service life of active participants is 9 years for the Retirement Plan and 8 years for those eligible for other post-retirement benefits. For further discussion of the Company's pension and other post-retirement benefits, refer to Other Matters in this Item 7, which includes a discussion of funding for the current year and the adoption of FASB revised accounting guidance for defined benefit pensions and other postretirement plans, and to Item 8 at Note H — Retirement Plan and Other Post Retirement Benefits.

RESULTS OF OPERATIONS

EARNINGS

2009 Compared with 2008

The Company's earnings were $100.7 million in 2009 compared with earnings of $268.7 million in 2008. The decrease in earnings of $168.0 million is primarily the result of lower earnings in the Exploration and Production, Pipeline and Storage and Utility segments and the All Other category, slightly offset by a lower loss in the Corporate category and higher earnings in the Energy Marketing segment, as shown in the table below. In the discussion that follows, note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted. Earnings were impacted by several events in 2009 and 2008, including:

2009 Events

- A non-cash $182.8 million impairment charge ($108.2 million after tax) recorded during the quarter ended December 31, 2008 for the Exploration and Production segment's oil and gas producing properties;
- A $2.8 million impairment in the value of certain landfill gas assets in the All Other category;
- A $1.1 million impairment in the value of the Company's 50% investment in ESNE (recorded in the All Other category), a limited liability company that owns an 80-megawatt, combined cycle, natural gas-fired power plant in the town of North East, Pennsylvania; and
- A $2.3 million death benefit gain on life insurance policies recognized in the Corporate category.

2008 Event

- A $0.6 million gain in the All Other category associated with the sale of Horizon Power's gas-powered turbine.

2008 Compared with 2007

The Company's earnings were $268.7 million in 2008 compared with earnings of $337.5 million in 2007. As previously discussed, the Company presented its Canadian operations in the Exploration and Production segment (in conjunction with the sale of SECI) as discontinued operations. The Company's earnings from continuing operations were $268.7 million in 2008 compared with $201.7 million in 2007. The Company's earnings from discontinued operations were $135.8 million in 2007. The increase in earnings from continuing operations is primarily the result of higher earnings in the Exploration and Production and Utility segments and the All Other category, slightly offset by lower earnings in the Corporate category and the Pipeline and Storage and Energy Marketing segments, as shown in the table below. Earnings from continuing operations and discontinued operations were impacted by the 2008 event discussed above and the following 2007 events:

2007 Events

- A $120.3 million gain on the sale of SECI, which was completed in August 2007. This amount is included in earnings from discontinued operations;
- A $4.8 million benefit to earnings in the Pipeline and Storage segment due to the reversal of a reserve established for all costs incurred related to the Empire Connector project recognized during June 2007;
- A $1.9 million benefit to earnings in the Pipeline and Storage segment associated with the discontinuance of hedge accounting for Empire's interest rate collar; and
- A $2.3 million benefit to earnings in the Energy Marketing segment related to the resolution of a purchased gas contingency.

Earnings (Loss) by Segment

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
Utility	$ 58,664	$ 61,472	$ 50,886
Pipeline and Storage	47,358	54,148	56,386
Exploration and Production	(10,238)	146,612	74,889
Energy Marketing	7,166	5,889	7,663
Total Reported Segments	102,950	268,121	189,824
All Other	(2,071)	5,779	6,292
Corporate	(171)	(5,172)	5,559
Total Earnings from Continuing Operations	100,708	268,728	201,675
Earnings from Discontinued Operations	—	—	135,780
Total Consolidated	$100,708	$268,728	$337,455

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
Retail Revenues:			
Residential	$ 850,088	$ 876,677	$ 848,693
Commercial	128,520	135,361	136,863
Industrial	7,213	7,419	8,271
	985,821	1,019,457	993,827
Off-System Sales	3,740	58,225	9,751
Transportation	111,483	113,901	102,534
Other	11,980	18,686	14,612
	$1,113,024	$1,210,269	$1,120,724

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30		
	2009	2008	2007
Retail Sales:			
Residential	58,835	57,463	60,236
Commercial	9,551	9,769	10,713
Industrial	515	552	727
	68,901	67,784	71,676
Off-System Sales	513	5,686	1,355
Transportation	59,751	64,267	62,240
	129,165	137,737	135,271

Degree Days

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Percent (Warmer) Colder Than Prior Year
2009:	Buffalo	6,692	6,701	0.1%	6.8%
	Erie	6,243	6,176	(1.1)%	6.9%
2008:	Buffalo	6,729	6,277	(6.7)%	0.1%
	Erie	6,277	5,779	(7.9)%	(3.8)%
2007:	Buffalo	6,692	6,271	(6.3)%	5.1%
	Erie	6,243	6,007	(3.8)%	5.6%

2009 Compared with 2008

Operating revenues for the Utility segment decreased \$97.2 million in 2009 compared with 2008. This decrease largely resulted from a \$54.5 million decrease in off-system sales revenue (see discussion below), a \$33.6 million decrease in retail gas sales revenues, a \$2.4 million decrease in transportation revenues, and a \$6.7 million decrease in other operating revenues.

The decrease in retail gas sales revenues of \$33.6 million was largely a function of the recovery of lower gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues). The recovery of lower gas costs resulted from a much lower cost of purchased gas. See further discussion of purchased gas below under the heading "Purchased Gas." The decrease in transportation revenues of \$2.4 million was primarily due to a 4.5 Bcf decrease in transportation throughput, largely the result of customer conservation efforts and the poor economy.

In the New York jurisdiction, the NYPSC issued an order providing for an annual rate increase of \$1.8 million beginning December 28, 2007. As part of this rate order, a rate design change was adopted that shifts a greater amount of cost recovery into the minimum bill amount, thus spreading the recovery of such costs more evenly throughout the year. As a result of this rate order, retail and transportation revenues for 2009 were \$2.2 million lower than revenues for 2008.

The Utility segment had off-system sales revenues of \$3.7 million and \$58.2 million for 2009 and 2008, respectively. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to margins in 2009 and 2008. The decrease in off-system sales revenue stems from Order No. 717 ("Final Rule"), which was issued by the FERC on October 16, 2008. The Final Rule seemingly held that a local distribution company making off-system sales on unaffiliated pipelines would be engaging in "marketing" that would require compliance with the FERC's standards of conduct. Accordingly, pending clarification of this issue from the FERC, as of November 1, 2008, Distribution Corporation ceased off-system sales activities. On October 15, 2009, the FERC released Order No. 717-A, which clarified that a local distribution company making off-system sales of gas that has been transported on non-affiliated pipelines is not subject to the standards of conduct. In light of and in reliance on this clarification, Distribution Corporation determined that it may resume engaging in off-system sales on non-affiliated pipelines. Such off-system sales resumed in November 2009.

The decrease in other operating revenues of \$6.7 million is largely related to amounts recorded in 2008 pursuant to rate settlements approved by the NYPSC. In accordance with these settlements, 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 2008, Distribution Corporation utilized \$5.6 million of the cost mitigation reserve, which increased other operating revenues, to recover previous undercollections of pension expenses. In 2009, Distribution Corporation utilized only \$0.2 million of the cost mitigation reserve. The impact of this \$5.4 million decrease in other operating revenues was offset by an equal decrease to operation and maintenance expense (thus there is no earnings impact).

2008 Compared with 2007

Operating revenues for the Utility segment increased $89.5 million in 2008 compared with 2007. This increase largely resulted from a $48.5 million increase in off-system sales revenue (see discussion below), a $25.6 million increase in retail gas sales revenues, an $11.3 million increase in transportation revenues, and a $4.1 million increase in other operating revenues.

The increase in retail gas sales revenues for the Utility segment was largely a function of the recovery of higher gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues), which more than offset the revenue impact of lower retail sales volumes, as shown in the table above. See further discussion of purchased gas below under the heading "Purchased Gas." This change was also affected by a base rate increase in the Pennsylvania jurisdiction (effective January 2007) that increased operating revenues by $4.0 million for 2008. The increase is included within both retail and transportation revenues in the table above.

In the New York jurisdiction, the NYPSC issued an order providing for an annual rate increase of $1.8 million beginning December 28, 2007. As part of this rate order, a rate design change was adopted that shifts a greater amount of cost recovery into the minimum bill amount, thus spreading the recovery of such costs more evenly throughout the year. This rate design change resulted in lower retail and transportation revenues (exclusive of the impact of higher gas costs) during the winter months compared to the prior year and higher retail and transportation revenues in the spring and summer months compared to the prior year. On a cumulative basis for 2008, the impact of this rate order has been to lower operating revenues by $1.4 million. The increase in transportation revenues was also due to a 2.0 Bcf increase in transportation throughput, largely the result of the migration of customers from retail sales to transportation service.

On November 17, 2006 the U.S. Court of Appeals vacated and remanded the FERC's Order No. 2004 regarding affiliate standards of conduct, with respect to natural gas pipelines. The Court's decision became effective on January 5, 2007, and on January 9, 2007, the FERC issued Order No. 690, its Interim Rule, designed to respond to the Court's decision. In Order No. 690, as clarified by the FERC on March 21, 2007, the FERC readopted, on an interim basis, certain provisions that existed prior to the issuance of Order No. 2004 that had made it possible for the Utility segment to engage in certain off-system sales without triggering the adverse consequences that would otherwise arise under the Order No. 2004 standards of conduct. As a result, the Utility segment resumed engaging in off-system sales on non-affiliated pipelines as of May 2007, resulting in total off-system sales revenues of $58.2 million and $9.8 million for 2008 and 2007, respectively. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to margins in 2008 and 2007.

The increase in other operating revenues of $4.1 million is largely related to amounts recorded pursuant to rate settlements approved by the NYPSC. In accordance with these settlements, 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 2008, Distribution Corporation utilized $5.6 million of the cost mitigation reserve, which increased other operating revenues, to recover previous undercollections of pension expenses. The impact of that increase in other operating revenues was offset by an equal amount of operation and maintenance expense (thus there is no earnings impact).

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, Empire 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 $8.17 per Mcf in 2009, a decrease of 27% from the average cost of $11.23 per Mcf in 2008. The average cost of purchased gas in 2008 was 12% higher than the average cost of $10.04 per Mcf in 2007. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

Earnings

2009 Compared with 2008

The Utility segment's earnings in 2009 were $58.7 million, a decrease of $2.8 million when compared with earnings of $61.5 million in 2008.

In the New York jurisdiction, earnings decreased by $3.0 million. This was primarily due to an increase in interest expense ($2.9 million) stemming from the borrowing by the New York jurisdiction of Distribution Corporation of a portion of the Company's April 2009 debt issuance. The April 2009 debt was issued at a significantly higher interest rate than the interest rates on debt that had matured in March 2009. The negative earnings impact of the December 28, 2007 rate order discussed above ($1.4 million) and routine regulatory adjustments ($0.7 million) also contributed to the decrease. The decrease was partially offset by a $2.6 million overall reduction in operating expenses (mostly other post-retirement benefits and pension expense).

In the Pennsylvania jurisdiction, earnings increased by $0.2 million. This was primarily due to the positive earnings impact of colder weather ($2.1 million), routine regulatory adjustments ($0.5 million) and lower operating expenses ($0.9 million). A decrease in normalized usage per account ($2.3 million), a higher effective tax rate ($1.4 million) and an increase in interest expense ($0.2 million) partially offset these increases. The phrase "usage per account" refers to the average gas consumption per customer account after factoring out any impact that weather may have had on consumption.

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. For 2009, the WNC reduced earnings by approximately $0.2 million, as the weather was colder than normal. For 2008, the WNC preserved earnings of approximately $2.5 million, as the weather was warmer than normal.

2008 Compared with 2007

The Utility segment's earnings in 2008 were $61.5 million, an increase of $10.6 million when compared with earnings of $50.9 million in 2007.

In the New York jurisdiction, earnings increased by $6.9 million. This was primarily due to a $3.6 million overall decrease in operating expenses (mostly other post-retirement benefits and bad debt expense), higher non-cash interest income on a pension-related regulatory asset ($2.6 million), a decrease in property, franchise, and other taxes ($0.9 million), a decrease in depreciation expense ($0.8 million), lower income tax expense ($0.7 million), lower interest expense ($0.2 million), and increased usage per account ($0.5 million). The impact of these items more than offset lower base rates due to the rate design change described above ($0.9 million), and routine regulatory adjustments that reduced earnings by $1.8 million.

In the Pennsylvania jurisdiction, earnings increased by $3.7 million. This was primarily due to a base rate increase ($2.6 million) that became effective January 2007, an increase in normalized usage ($1.3 million), a decrease in bad debt expense ($1.1 million), and a decrease in property, franchise, and other taxes ($0.3 million). Warmer weather ($1.6 million) partially offset these increases.

The impact of weather on the Utility segment's New York rate jurisdiction is tempered by a 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 2008 and 2007, the WNC preserved earnings of approximately $2.5 million and $2.3 million, respectively, as the weather was warmer than normal.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
Firm Transportation	$139,034	$122,321	$118,771
Interruptible Transportation	3,175	4,330	4,161
	142,209	126,651	122,932
Firm Storage Service	66,711	67,020	66,966
Interruptible Storage Service	20	14	169
	66,731	67,034	67,135
Other	10,333	22,871	21,899
	$219,273	$216,556	$211,966

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30		
	2009	2008	2007
Firm Transportation	356,771	353,173	351,113
Interruptible Transportation	4,070	5,197	4,975
	360,841	358,370	356,088

2009 Compared with 2008

Operating revenues for the Pipeline and Storage segment increased $2.7 million in 2009 as compared with 2008. The increase was primarily due to a $15.6 million increase in transportation revenue primarily due to higher revenues from the Empire Connector and new contracts for transportation service. Partially offsetting this increase, efficiency gas revenues decreased $11.5 million (reported as a part of other revenue in the table above). The majority of this decrease was due to significantly lower gas prices in 2009 as compared to 2008. Under Supply Corporation's tariff with suppliers, Supply Corporation is allowed to retain a set percentage of shipper-supplied gas to cover compressor fuel costs and other operational purposes. To the extent that Supply Corporation does not need all of the gas to cover such operational needs, it is allowed to keep the excess gas as inventory. That inventory is later sold to customers. The excess gas that is retained as inventory represents efficiency gas revenue to Supply Corporation.

2008 Compared with 2007

Operating revenues for the Pipeline and Storage segment increased $4.6 million in 2008 as compared with 2007. The majority of the increase was the result of increased transportation revenues ($3.7 million) due to the fact that the Pipeline and Storage segment was able to renew existing contracts at higher rates due to favorable market conditions for transportation service associated with storage. In addition, there were increased efficiency gas revenues ($0.8 million) primarily due to higher gas prices in the current year.

Earnings

2009 Compared with 2008

The Pipeline and Storage segment's earnings in 2009 were $47.4 million, a decrease of $6.7 million when compared with earnings of $54.1 million in 2008. The decrease was primarily due to the earnings impact associated with a decrease in efficiency gas revenues ($7.5 million), as discussed above. In addition, higher interest expense ($5.1 million), higher depreciation expense ($1.5 million), and a decrease in the allowance for funds used during construction ($2.0 million) also contributed to the decrease in earnings. The increase in interest expense can be attributed to higher debt balances and a higher average interest rate on borrowings. The increase in the average interest rate stems from the borrowing of a portion of the Company's April 2009 debt issuance. The increase in depreciation expense can be attributed primarily to a revision of accumulated depreciation combined with the increased depreciation associated with placing the Empire Connector in service in December 2008. The decease in the allowance for funds used during construction was due to completion of the Empire Connector project in December 2008. Whereas the allowance for funds used during construction related to the Empire Connector project was recorded throughout 2008, it was only recorded for three months in 2009. These earnings decreases were partially offset by the earnings impact associated with higher transportation revenues ($9.7 million), as discussed above.

2008 Compared with 2007

The Pipeline and Storage segment's earnings in 2008 were $54.1 million, a decrease of $2.2 million when compared with earnings of $56.4 million in 2007. The main factors contributing to this decrease were higher operation and maintenance expenses ($6.1 million), primarily caused by the non-recurrence in 2008 of a reversal of a reserve for preliminary survey costs related to the Empire Connector project during 2007 ($4.8 million). In addition, there was a $1.9 million positive earnings impact during 2007 associated with the discontinuance of hedge accounting for Empire's interest rate collar that did not recur during 2008, and the Pipeline and Storage segment experienced higher interest costs ($1.5 million). These earnings decreases were offset by the earnings impact associated with higher transportation revenues ($2.4 million), an increase in the allowance for funds used during construction ($4.2 million) and the earnings impact associated with higher efficiency gas revenues ($0.5 million).

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
Gas (after Hedging) from Continuing Operations	$154,582	$202,153	$143,785
Oil (after Hedging) from Continuing Operations	219,046	250,965	167,627
Gas Processing Plant from Continuing Operations	24,686	49,090	37,528
Other from Continuing Operations	432	(944)	1,147
Intrasegment Elimination from Continuing Operations(1)	(15,988)	(34,504)	(26,050)
Operating Revenues from Continuing Operations	$382,758	$466,760	$324,037
Operating Revenues from Canada — Discontinued Operations	$ —	$ —	$ 50,495

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

Production

	Year Ended September 30		
	2009	2008	2007
Gas Production *(MMcf)*			
Gulf Coast	9,886	11,033	10,356
West Coast	4,063	4,039	3,929
Appalachia	8,335	7,269	5,555
Total Production from Continuing Operations	22,284	22,341	19,840
Canada — Discontinued Operations	—	—	6,426
Total Production	22,284	22,341	26,266
Oil Production *(Mbbl)*			
Gulf Coast	640	505	717
West Coast	2,674	2,460	2,403
Appalachia	59	105	124
Total Production from Continuing Operations	3,373	3,070	3,244
Canada — Discontinued Operations	—	—	206
Total Production	3,373	3,070	3,450

Average Prices

	Year Ended September 30		
	2009	2008	2007
Average Gas Price/Mcf			
Gulf Coast	$ 4.54	$ 10.03	$ 6.58
West Coast	$ 3.91	$ 8.71	$ 6.54
Appalachia	$ 5.52	$ 9.73	$ 7.48
Weighted Average for Continuing Operations	$ 4.79	$ 9.70	$ 6.82
Weighted Average After Hedging for Continuing Operations(1)	$ 6.94	$ 9.05	$ 7.25
Canada — Discontinued Operations	$ —	$ —	$ 6.09
Average Oil Price/Barrel (bbl)			
Gulf Coast	$54.58	$107.27	$63.04
West Coast(2)	$50.90	$ 98.17	$56.86
Appalachia	$56.15	$ 97.40	$62.26
Weighted Average for Continuing Operations	$51.69	$ 99.64	$58.43
Weighted Average After Hedging for Continuing Operations(1)	$64.94	$ 81.75	$51.68
Canada — Discontinued Operations	$ —	$ —	$50.06

(1) Refer to further discussion of hedging activities below under "Market Risk Sensitive Instruments" and in Note G — Financial Instruments in Item 8 of this report.

(2) Includes low gravity oil which generally sells for a lower price.

2009 Compared with 2008

Operating revenues from continuing operations for the Exploration and Production segment decreased $84.0 million in 2009 as compared with 2008. Gas production revenue after hedging from continuing operations decreased $47.6 million primarily due to a $2.11 per Mcf decrease in weighted average prices after hedging. Gas production from continuing operations was virtually flat with the prior year as production decreases in the Gulf Coast region were substantially offset by production increases in the Appalachian region. The decrease in gas production from continuing operations that occurred in the Gulf Coast region (1,147 MMcf) was a result of lingering shut-ins caused by Hurricanes Edouard, Gustav and Ike in September 2008. While Seneca's properties sustained only superficial damage from the hurricanes, two significant producing properties were shut-in for a significant portion of the current fiscal year due to repair work on third party pipelines and onshore processing facilities. One of the properties was back on line by March 31, 2009 and the other property was back on line by the end of April 2009. The increase in gas production from continuing operations in the Appalachian region of 1,066 MMcf resulted from additional wells drilled throughout fiscal 2008 that came on line in 2009. Oil production revenue after hedging from continuing operations decreased \$31.9 million due to a \$16.81 per barrel decrease in weighted average prices after hedging, which more than offset an increase in oil production from continuing operations of 303,000 barrels (primarily from the West Coast and Gulf Coast regions). In addition, there was a \$5.9 million decrease in gross processing plant revenues from continuing operations (net of eliminations) due to a reduction in the commodity prices of residual gas and liquids sold at Seneca's processing plants in the West Coast and Appalachian regions.

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.

2008 Compared with 2007

Operating revenues from continuing operations for the Exploration and Production segment increased \$142.7 million in 2008 as compared with 2007. Oil production revenue after hedging from continuing operations increased \$83.3 million due primarily to a \$30.07 per barrel increase in weighted average prices after hedging, which more than offset a decrease in oil production of 174,000 barrels. Gas production revenue after hedging from continuing operations increased \$58.4 million due to a \$1.80 per Mcf increase in weighted average prices after hedging and a 2,501 MMcf increase in production from continuing operations. The increase in gas production from continuing operations occurred primarily in the Appalachian region (1,714 MMcf), consistent with increased drilling activity in the region. The Gulf Coast region also contributed significantly to the increase in natural gas production from continuing operations (677 MMcf). Production from new fields in 2008 (primarily in the High Island area) outpaced declines in production from some existing fields, period to period. Production in this region would have been higher if not for the hurricane activity during the month of September 2008. As a result of hurricanes Edouard, Gustav and Ike, production was shut in for much of the month of September, resulting in estimated lost production of approximately 804 MMcf of natural gas and 45 Mbbl of oil.

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.

Earnings

2009 Compared with 2008

The Exploration and Production segment's loss from continuing operations for 2009 was \$10.2 million, compared with earnings from continuing operations of \$146.6 million for 2008, a decrease of \$156.8 million. The decrease in earnings is primarily the result of an impairment charge of \$108.2 million, as discussed above. In addition, lower crude oil prices, lower natural gas prices, and lower natural gas production decreased earnings by \$36.9 million, \$30.6 million, and \$0.3 million, respectively, while higher crude oil production increased earnings by \$16.1 million. Lower interest income (\$5.5 million) and higher operating expenses (\$1.7 million) further reduced earnings. In addition, there was a \$3.8 million decrease in earnings caused by a reduction in the commodity prices of residual gas and liquids sold at Seneca's processing plants in the West Coast and Appalachian regions. The decrease in interest income is due to lower interest rates and lower temporary cash investment balances. The increase in operating expenses is due to an increase in bad debt expense as a result of a customer's bankruptcy filing, and higher personnel costs in the Appalachian region. These earnings decreases were partially offset by lower interest expense (\$5.4 million), lower lease operating costs (\$2.6 million), lower depletion expense (\$0.9 million), and lower income tax expense (\$4.2 million). The decline in interest expense is primarily due to a lower average amount of debt outstanding. The reduction in lease operating expenses is primarily due to a reduction in steam fuel costs in the West Coast region and lower production taxes in the Gulf Coast region. The decrease in depletion is primarily due to a lower full cost pool balance after the impairment charge taken during the quarter ended December 31, 2008.

2008 Compared with 2007

The Exploration and Production segment's earnings from continuing operations for 2008 were $146.6 million, an increase of $71.7 million when compared with earnings from continuing operations of $74.9 million for 2007. Higher crude oil prices, higher natural gas prices and higher natural gas production increased earnings by $60.0 million, $26.2 million and $11.8 million, respectively, while lower crude oil production decreased earnings by $5.8 million. Higher lease operating costs ($11.9 million), higher depletion expense ($9.1 million), higher income tax expense ($1.1 million) and higher general and administrative and other operating expenses ($6.2 million) also negatively impacted earnings. Lower interest expense and higher interest income of $6.6 million and $0.7 million, respectively, partially offset these decreases to earnings. The increase in lease operating costs resulted from the start-up of production at the High Island 24L field in October 2007, higher steaming costs in California, and an increase in costs associated with a higher number of producing properties in Appalachia. The increase in depletion expense was caused by higher production and an increase in the depletable base. The increase in general and administrative and other operating expenses resulted from an increase in staffing and associated costs for the growing Appalachia division combined with the recognition of actual plugging costs in excess of previously accrued amounts.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
Natural Gas (after Hedging)	$398,205	$551,243	$413,405
Other	116	(11)	207
	$398,321	$551,232	$413,612

Energy Marketing Volume

	Year Ended September 30		
	2009	2008	2007
Natural Gas — (MMcf)	60,858	56,120	50,775

2009 Compared with 2008

Operating revenues for the Energy Marketing segment decreased $152.9 million in 2009 as compared with 2008. The decrease is primarily due to lower gas sales revenue, due to a lower average price of natural gas that was recovered through revenues. This decline was somewhat offset by an increase in volume sold. The increase in sales volume is largely attributable to colder weather as well as an increase in sales transactions undertaken at the Niagara pipeline delivery point to offset certain basis risks that the Energy Marketing segment was exposed to under certain fixed basis commodity purchase contracts for Appalachian production. Such offsetting transactions had the effect of increasing revenue and volume sold with minimal impact to earnings.

2008 Compared with 2007

Operating revenues for the Energy Marketing segment increased $137.6 million in 2008 as compared with 2007. The increase is primarily due to higher gas sales revenue, as a result of an increase in the price of natural gas that was recovered through revenues, coupled with an increase in volume sold. The increase in volume is primarily attributable to an increase in volume sold to low-margin wholesale customers, as well as an increase in the number of commercial and industrial customers served by the Energy Marketing segment. The increase in volume also reflects certain sales transactions undertaken at the Niagara pipeline delivery point to offset certain basis risks that the Energy Marketing segment was exposed to under certain fixed basis commodity purchase contracts for Appalachian production. Such offsetting transactions had the effect of increasing revenue and volume sold with minimal impact to earnings.

Earnings

2009 Compared with 2008

The Energy Marketing segment's earnings in 2009 were $7.2 million, an increase of $1.3 million when compared with earnings of $5.9 million in 2008. Higher margin of $1.5 million combined with lower operating costs of $0.4 million (primarily due to a decline in bad debt expense) are responsible for the increase in earnings. These increases were partially offset by higher income tax expense of $0.4 million in 2009 as compared to 2008. The increase in margin was primarily driven by lower pipeline transportation fuel costs due to lower natural gas commodity prices, an unfavorable pipeline imbalance resolution in fiscal 2008 that did not recur in fiscal 2009, and improved average margins per Mcf, partially offset by higher pipeline reservation charges related to additional storage capacity.

2008 Compared with 2007

The Energy Marketing segment's earnings in 2008 were $5.9 million, a decrease of $1.8 million when compared with earnings of $7.7 million in 2007. Higher operating costs of $1.1 million (primarily due to an increase in bad debt expense) coupled with lower margin of $1.1 million are primarily responsible for the decrease in earnings. A major factor in the margin decrease is the non-recurrence of a purchased gas expense adjustment recorded during the quarter ended March 31, 2007. During that quarter, the Energy Marketing segment reversed an accrual for $2.3 million of purchased gas expense due to a resolution of a contingency. The increase in volume noted above, the profitable sale of certain gas held as inventory, and the marketing flexibility that the Energy Marketing segment derives from its contracts for significant storage capacity partially offset the margin decrease associated with the purchased gas adjustment.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate operations primarily includes the operations of Highland, Seneca's Northeast Division, Midstream Corporation, Horizon LFG, Horizon Power, former International segment activity and corporate operations. Highland and Seneca's Northeast Division market timber from their New York and Pennsylvania land holdings, own two sawmill operations in northwestern Pennsylvania and process timber consisting primarily of high quality hardwoods. Midstream Corporation is a Pennsylvania corporation formed to build, own and operate natural gas processing and pipeline gathering facilities in the Appalachian region. Horizon LFG owns and operates short-distance landfill gas pipeline companies. Horizon Power's activity primarily consists of equity method investments in Seneca Energy, Model City and ESNE. Horizon Power has a 50% ownership interest in each of these entities. The income from these equity method investments is reported as Income from Unconsolidated Subsidiaries on the Consolidated Statements of Income. 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.

Earnings

2009 Compared with 2008

All Other and Corporate operations had a loss of $2.2 million in 2009, a decrease of $2.8 million compared with earnings of $0.6 million for 2008. The decrease in earnings was largely attributable to lower margins from lumber, log and timber rights sales ($2.5 million), lower margins from Horizon LFG ($1.6 million), lower interest income ($0.6 million), lower income from Horizon Power's investments in unconsolidated subsidiaries

($2.0 million), and higher interest expense ($3.1 million). The decrease in margins from lumber, log and timber rights sales is a result of a decline in revenues due to unfavorable market conditions. The decrease in margins from Horizon LFG is due to the decrease in the price of gas and lower volumes due to the poor economy. The increase in interest expense was primarily the result of higher borrowings at a higher interest rate (mostly due to the $250 million of 8.75% notes that were issued in April 2009). In addition, during 2009, ESNE, an unconsolidated subsidiary of Horizon Power, recorded an impairment charge of $3.6 million. Horizon Power's 50% share of the impairment was $1.8 million ($1.1 million on an after tax basis). In 2009, Horizon LFG recorded an impairment charge of $4.6 million on its landfill gas assets ($2.8 million on an after-tax basis). Also, Horizon Power recognized a gain on the sale of a turbine ($0.6 million) during 2008 that did not recur in 2009. These earnings decreases were partially offset by lower operating costs ($4.9 million). In 2008, the proxy contest with New Mountain Vantage GP, L.L.C. led to an increase in operating costs, which did not recur in 2009. In addition, lower income tax expense ($4.3 million) and a gain on life insurance policies held by the Company ($2.3 million) further offset the earnings decrease.

The impairment charge of $4.6 million recorded by Horizon LFG during 2009 (as discussed above) was comprised of a $2.6 million reduction in intangible assets related to long-term gas purchase contracts and a $2.0 million reduction in property, plant and equipment. The impairment was recorded due to the loss of the primary customer at a landfill gas site and the anticipated shut-down of the site. This impairment charge reduced the recorded value of intangible assets and property, plant and equipment associated with this site to zero at September 30, 2009.

The impairment charge of $3.6 million recorded by ESNE during 2009 (as discussed above) was driven by a significant decrease in "run time" for the plant given the economic downturn and the resulting decrease in demand for electric power.

2008 Compared with 2007

All Other and Corporate operations had earnings of $0.6 million in 2008, a decrease of $11.3 million compared with earnings of $11.9 million for 2007. The positive earnings impact of higher income from unconsolidated subsidiaries ($0.9 million) and a gain on the sale of a turbine by Horizon Power ($0.6 million) were more than offset by higher operating costs ($5.9 million), higher income tax expense ($0.9 million), lower interest income ($1.5 million) and lower margins from lumber, log and timber rights sales ($4.2 million). The increase in operating costs is primarily the result of the proxy contest with New Mountain Vantage GP, L.L.C. The decrease in margins from lumber, log and timber rights sales is a result of a decline in revenues due to unfavorable market conditions and wet weather conditions that hampered harvesting. In addition, in 2007, Seneca's Northeast Division sold 3.1 million board feet of timber rights and recorded a gain of $1.6 million in other revenues, which did not recur in 2008.

INTEREST INCOME

Interest income was $5.0 million lower in 2009 as compared to 2008. Lower cash investment balances in the Exploration and Production segment and lower interest rates on such investments were the primary factors contributing to this decrease.

Interest income was $9.3 million higher in 2008 as compared to 2007. The main reason for this increase was a $4.0 million increase in interest income on a pension-related regulatory asset in the Utility segment's New York jurisdiction. The Exploration and Production segment also contributed $3.8 million to this increase as a result of the investment of cash proceeds from the sale of SECI in August 2007.

OTHER INCOME

Other income was $0.8 million lower in 2009 as compared to 2008. This decrease is attributed to a $1.7 million decrease in the allowance for funds used during construction in the Pipeline and Storage segment associated with the Empire Connector project. Horizon Power recognized a $0.9 million pre-tax gain on the sale of a turbine during 2008 that did not recur in 2009. These decreases were partially offset by a death benefit gain on life insurance policies of $2.3 million recognized in the Corporate category during 2009.

Other income was $2.4 million higher in 2008 as compared to 2007. This increase is primarily attributed to a $4.2 million increase in the allowance for funds used during construction in the Pipeline and Storage segment associated with the Empire Connector project. It also reflects a $0.9 million pre-tax gain on the sale of a turbine during 2008. These increases were partially offset by the non-recurrence of a death benefit gain on life insurance proceeds of $1.9 million recognized in the Corporate category in 2007.

INTEREST CHARGES

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

Interest on long-term debt increased $9.3 million in 2009 as compared to 2008. The increase in 2009 was primarily the result of a higher average amount of long-term debt outstanding combined with higher average interest rates. In April 2009, the Company issued $250 million of 8.75% senior, unsecured notes due in May 2019. This increase was partially offset by the repayment of $100 million of 6% medium-term notes that matured in March 2009.

Interest on long-term debt increased $1.7 million in 2008 as compared to 2007. The increase in 2008 was primarily the result of a higher average amount of long-term debt outstanding. In April 2008, the Company issued $300 million of 6.5% senior, unsecured notes due in April 2018. This increase was partially offset by the repayment of $200 million of 6.303% medium-term notes that matured on May 27, 2008.

Other interest charges increased $3.6 million in 2009 compared to 2008. The increase in 2009 was primarily caused by a $2.3 million increase in interest expense on regulatory deferrals (primarily deferred gas costs) in the Utility segment's New York jurisdiction combined with a $0.7 million decrease in the allowance for borrowed funds used during construction related to the Empire Connector project.

Other interest charges decreased $2.2 million in 2008 compared to 2007. The decrease in 2008 was primarily caused by a $1.7 million increase in the allowance for borrowed funds used during construction related to the Empire Connector project.

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		
	2009	2008	2007
		(Millions)	
Provided by Operating Activities	$ 609.4	$ 482.8	$ 394.2
Capital Expenditures	(309.9)	(397.7)	(276.7)
Investment in Subsidiary, Net of Cash Acquired	(34.9)	—	—
Investment in Partnerships	(1.3)	—	(3.3)
Net Proceeds from Sale of Foreign Subsidiaries	—	—	232.1
Cash Held in Escrow	(2.0)	58.4	(58.2)
Net Proceeds from Sale of Oil and Gas Producing Properties	3.6	5.9	5.1
Other Investing Activities	(2.8)	4.4	(0.8)
Reduction of Long-Term Debt	(100.0)	(200.0)	(119.6)
Net Proceeds from Issuance of Long-Term Debt	247.8	296.6	—
Net Proceeds from Issuance of Common Stock	28.2	17.4	17.5
Dividends Paid on Common Stock	(104.2)	(103.7)	(100.6)
Excess Tax Benefits Associated with Stock- Based Compensation Awards	5.9	16.3	13.7
Shares Repurchased under Repurchase Plan	—	(237.0)	(48.1)
Effect of Exchange Rates on Cash	—	—	(0.1)
Net Increase (Decrease) in Cash and Temporary Cash Investments	$ 339.8	$ (56.6)	$ 55.2

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, impairment of investment in partnership, deferred income taxes, income or loss from unconsolidated subsidiaries net of cash distributions and gain on sale of discontinued operations.

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 may 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 the straight fixed-variable rate design used by Supply Corporation and Empire.

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

Net cash provided by operating activities totaled $609.4 million in 2009, an increase of $126.6 million compared with the $482.8 million provided by operating activities in 2008. The increase is primarily due to the timing of gas cost recovery in the Utility segment. As gas prices decreased significantly during 2009, the Company's Utility segment experienced an over-recovery of gas costs that is reflected in Amounts Payable to Customers on the Company's Consolidated Balance Sheet at September 30, 2009. At September 30, 2008, the

Company's Utility segment was in an under-recovery position. It is expected that the over-recovery at September 30, 2009 will be passed back to customers in 2010.

Net cash provided by operating activities totaled $482.8 million in 2008, an increase of $88.6 million compared with the $394.2 million provided by operating activities in 2007. In the Utility segment, lower cash payments for gas costs offset partially by lower cash receipts for retail and transportation services resulted in higher cash provided by operations. In the Exploration and Production segment, cash provided by operations increased due to higher cash receipts from the sale of oil and gas production, largely a result of higher commodity prices. This increase in the Exploration and Production segment was partially offset by a decrease in cash provided by operations that resulted from the sale of SECI, a discontinued operation, in August 2007. Cash provided by operating activities from SECI was $0.3 million in 2007. Partially offsetting these increases, the Energy Marketing segment experienced a decrease in cash provided by operations due to the timing of gas cost recovery.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company's expenditures from continuing operations for long-lived assets totaled $339.2 million, $414.5 million and $250.9 million in 2009, 2008 and 2007, respectively. The table below presents these expenditures:

	Year Ended September 30		
	2009	2008	2007
		(Millions)	
Utility:			
Capital Expenditures	$ 56.2	$ 57.5	$ 54.2
Pipeline and Storage:			
Capital Expenditures	50.1(1)	165.5(1)	43.2
Exploration and Production:			
Capital Expenditures	188.3(2)	192.2	146.7
Investment in Subsidiary	34.9(3)	—	—
All Other and Corporate:			
Capital Expenditures	8.7(4)	1.7	3.5
Investment in Partnerships	1.3	—	3.3
Eliminations	(0.3)(5)	(2.4)(6)	—
Total Expenditures from Continuing Operations	$339.2	$414.5	$250.9(7)

(1) Amount for 2009 excludes $16.8 million of accrued capital expenditures related to the Empire Connector project accrued at September 30, 2008 and paid during the year ended September 30, 2009. This amount was included in 2008 capital expenditures shown in the table above, but was excluded from the Consolidated Statement of Cash Flows at September 30, 2008 since it represented a non-cash investing activity at that date. The amount has been included in the Consolidated Statement of Cash Flows at September 30, 2009.

(2) Amount for 2009 includes $9.1 million of accrued capital expenditures, the majority of which was in the Appalachian region. This amount has been excluded from the Consolidated Statement of Cash Flows at September 30, 2009 since it represents a non-cash investing activity at that date.

(3) Investment amount is net of $4.3 million of cash acquired.

(4) Amount for 2009 includes $0.7 million of accrued capital expenditures related to the construction of the Midstream Covington Gathering System. This amount has been excluded from the Consolidated Statement of Cash Flows at September 30, 2009 since it represents a non-cash investing activity at that date.

(5) Represents $0.3 million of capital expenditures in the Pipeline and Storage segment for the purchase of pipeline facilities from the Appalachian region of the Exploration and Production segment during the quarter ended December 31, 2008.

(6) Represents $2.4 million of capital expenditures included in the Appalachian region of the Exploration and Production segment for the purchase of storage facilities, buildings, and base gas from Supply Corporation during the quarter ended March 31, 2008.

(7) Excludes expenditures for long-lived assets associated with discontinued operations of $29.1 million.

Utility

The majority of the Utility capital expenditures for 2009, 2008 and 2007 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 for 2009 and 2008 were related to the Empire Connector project, which was placed into service on December 10, 2008, as well as for additions, improvements, and replacements to this segment's transmission and gas storage systems. The majority of the Pipeline and Storage segment's capital expenditures for 2007 were made for additions, improvements, and replacements to this segment's transmission and gas storage systems. The Empire Connector project was completed for a cost of approximately $192 million. The Company capitalized Empire Connector project costs of $27.3 million, $149.2 million and $15.5 million for the years ended September 30, 2009, 2008 and 2007, respectively.

Exploration and Production

In 2009, the Exploration and Production segment's capital expenditures were primarily well drilling and completion expenditures and included approximately $18.3 million for the Gulf Coast region, substantially all of which was for the off-shore program in the shallow waters of the Gulf of Mexico, $31.4 million for the West Coast region and $138.6 million for the Appalachian region. These amounts included approximately $24.2 million spent to develop proved undeveloped reserves.

In July 2009, the Company's wholly-owned subsidiary in the Exploration and Production segment, Seneca, purchased Ivanhoe Energy's United States oil and gas operations for approximately $39.2 million in cash (including cash acquired of $4.3 million). The cash acquired at acquisition includes $2.0 million held in escrow at September 30, 2009. Seneca placed this amount in escrow as part of the purchase price, and in accordance with the purchase agreement, this amount will remain in escrow for one year from the closing of the transaction provided there are no pending disputes or actions regarding obligations and liabilities required to be satisfied or discharged by Ivanhoe Energy. This purchase complements the segment's existing oil producing assets in the Midway Sunset Field in California. This acquisition was funded with cash on hand.

In 2008, the Exploration and Production segment's capital expenditures were primarily well drilling and completion expenditures and included approximately $63.6 million for the Gulf Coast region, substantially all of which was for the off-shore program in the shallow waters of the Gulf of Mexico, $62.8 million for the West Coast region and $65.8 million for the Appalachian region. These amounts included approximately $25.4 million spent to develop proved undeveloped reserves. The Appalachian region capital expenditures include $2.4 million for the purchase of storage facilities, buildings, and base gas from Supply Corporation, as shown in the table above.

In 2007, the Exploration and Production segment's capital expenditures were primarily well drilling and completion expenditures and included approximately $66.2 million for the Gulf Coast region, substantially all of which was for the off-shore program in the Gulf of Mexico, $41.4 million for the West Coast region and $39.1 million for the Appalachian region. These amounts included approximately $30.3 million spent to develop proved undeveloped reserves.

All Other and Corporate

In 2009, the majority of the All Other and Corporate category's expenditures for long-lived assets were for the construction of Midstream Corporation's Covington Gathering System, as discussed below. Expenditures for long-lived assets for 2009 also included a $1.3 million capital contribution made by NFG Midstream Processing, LLC in the Whitetail Processing plant, as discussed below.

In 2008, the majority of the All Other and Corporate category's expenditures for long-lived assets were for construction of a lumber sorter for Highland's sawmill operations that was placed into service in October 2007, as well as for purchases of equipment for Highland's sawmill and kiln operations. Additionally, Horizon Power sold a gas-powered turbine in March 2008 that it had planned to use in the development of a co-generation plant. Horizon Power received proceeds of $5.3 million and recorded a pre-tax gain of $0.9 million associated with the sale.

In 2007, the All Other and Corporate category expenditures for long-lived assets included a $3.3 million capital contribution to Seneca Energy by Horizon Power. Seneca Energy generates and sells electricity using methane gas obtained from landfills owned by outside parties. Horizon Power funded its capital contributions with short-term borrowings. Additionally, the All Other and Corporate category expenditures for long-lived assets also were for the construction of two new kilns that were placed into service during the quarter ended June 30, 2007, as well as construction of a lumber sorter for Highland's sawmill operations.

Estimated Capital Expenditures

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

	Year Ended September 30		
	2010	2011	2012
		(Millions)	
Utility	$ 60.0	$ 58.0	$ 58.0
Pipeline and Storage	51.0	227.0	240.0
Exploration and Production(1)	255.0	417.0	497.0
All Other	47.0	21.0	21.0
	$413.0	$723.0	$816.0

(1) Includes estimated expenditures for the years ended September 30, 2010, 2011 and 2012 of approximately $42 million, $56 million and $28 million, respectively, to develop proved undeveloped reserves.

Utility

Estimated capital expenditures for the Utility segment in 2010 will be concentrated in the areas of main and service line improvements and replacements and, to a lesser extent, the purchase of new equipment.

Pipeline and Storage

Estimated capital expenditures for the Pipeline and Storage segment in 2010 will be concentrated on the replacement of transmission and storage lines, the reconditioning of storage wells and improvements of compressor stations.

In light of the growing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia — specifically in the Marcellus Shale producing area — Supply Corporation and Empire are actively pursuing several expansion projects. Supply Corporation is moving forward with two strategic compressor horsepower expansions, both supported by signed precedent agreements with Appalachian producers, designed to move anticipated Marcellus production gas to markets beyond Supply Corporation's pipeline system.

The first strategic horsepower expansion project involves new compression along Supply Corporation's Line N, increasing that line's capacity into Texas Eastern's Holbrook Station in southwestern Pennsylvania

("Line N Expansion Project"). This project is designed and contracted for 150,000 Dth/day of firm transportation, and will allow anticipated Marcellus production located in the vicinity of Line N to flow south and access markets off Texas Eastern's system, with a projected in-service date of November 2011. Supply Corporation is in the process of preparing an NGA Section 7(c) application to the FERC for approval of the Line N Expansion Project. The preliminary cost estimate for the Line N Expansion Project is $23 million. The forecasted expenditures for this project over the next three years are as follows: $0.9 million in 2010, $18.5 million in 2011, and $3.6 million in 2012. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. As of September 30, 2009, less than $0.1 million has been spent to study the Line N Expansion Project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2009.

The second strategic horsepower expansion project involves the addition of compression at Supply Corporation's existing interconnect with Tennessee Gas Pipeline at Lamont, Pennsylvania, with a projected in-service date of May 2010 ("Lamont Project"). The Lamont Project is designed and contracted for 40,000 Dth/day of firm transportation and will afford shippers a transportation path from their anticipated Marcellus production located in Elk and Cameron Counties, Pennsylvania to markets attached to Tennessee Gas Pipeline's 300 Line. The Lamont Project will not require an NGA Section 7(c) application, and will instead be constructed under Supply Corporation's existing blanket construction certificate authority from the FERC. The preliminary cost estimate for the Lamont Project is $6 million, all of which is forecasted to occur in 2010. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. As of September 30, 2009, less than $0.1 million has been spent to study the Lamont Project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2009.

In addition, Supply Corporation continues to actively pursue its largest planned expansion, the West-to-East/Appalachian Lateral pipeline project. The Appalachian Lateral project is routed through areas in Pennsylvania where producers are actively drilling and are seeking market access for their newly discovered reserves. The Appalachian Lateral will complement Supply Corporation's original West to East ("W2E") project, which was designed to transport Rockies gas supply from Clarington, Ohio to the Ellisburg/Leidy/Corning area. The Appalachian Lateral will transport gas supply from Pennsylvania's producing area to the Overbeck area of Supply Corporation's existing system, from which some of the facilities associated with the W2E project will move the gas to eastern market points, including Leidy, Pennsylvania, and to interconnections with Millennium and Empire at Corning, New York. Preliminary engineering routing analysis, project cost estimate and rate design have been completed, and prospective shippers have been offered precedent agreements for their consideration. This project will require an NGA Section 7(c) application, which Supply Corporation has not filed. The capital cost of all phases of the Appalachian Lateral/W2E transportation projects is estimated to be in the range of $750 million to $1 billion. As of September 30, 2009, approximately $0.6 million has been spent to study the Appalachian Lateral/W2E transportation projects, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2009.

Supply Corporation anticipates the development of the W2E/Appalachian Lateral project will occur in phases, and based on requests from the Marcellus producing community for transportation service commencing as early as 2011, Supply Corporation began a binding Open Season on August 26, 2009. This Open Season offered transportation capacity on two initial phases ("Phase I" and "Phase II") of the W2E pipeline project. The capital cost of these two phases is estimated to be $257 million. Phase I is designed to transport approximately 200,000 Dth/day from the Marcellus producing area through a new 32-mile pipeline to be constructed through Elk, Cameron, and Clinton Counties to the Leidy Hub, with an anticipated in-service date of late 2011. Phase II, with a late 2012 projected in-service date, consists of an additional 50 miles of new pipeline and compression extending through Clearfield and Jefferson Counties to Supply Corporation's Line K system and would provide additional transportation capacity of at least 300,000 Dth/day. The forecasted expenditures for Phase I and Phase II of this project over the next three years are as follows: $6.0 million in 2010, $108.0 million in 2011, and $143.0 million in 2012. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above.

This binding Open Season concluded on October 8, 2009 with significant participation by Marcellus producers. Supply Corporation received binding requests for 175,000 Dth/day of firm transportation capacity and expects to execute the signed precedent agreements submitted by those Marcellus producers. Supply Corporation is pursuing post-Open Season capacity requests for the remaining Phase I and Phase II capacity and expects to continue marketing efforts for all sections of the W2E and Appalachian Lateral projects. The timeline associated with the W2E and Appalachian Lateral projects will depend on market development.

In conjunction with the Appalachian Lateral and W2E transportation projects, Supply Corporation plans to develop new storage capacity by expanding certain of its existing storage facilities. The expansion of these fields could provide incremental storage capacity of approximately 8.5 MMDth and incremental withdrawal deliverability of up to 121 MDth of natural gas per day, with service commencing in early 2013. Supply Corporation expects that the availability of this incremental storage capacity will complement the Appalachian Lateral/W2E pipeline transportation projects and help balance the increasing flow of Appalachian and Rockies gas supply through the western Pennsylvania area, and the growing demand for gas on the east coast. This storage expansion project will require an NGA Section 7(c) application, which Supply Corporation has not yet filed. Preliminary cost estimates for the storage expansion project is $78 million. The forecasted expenditures for this project over the next three years are as follows: $0.4 million in 2010, $0.2 million in 2011, and $67.1 million in 2012. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. As of September 30, 2009, approximately $1.0 million has been spent to study the storage expansion project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2009. The timeline associated with the W2E and Appalachian Lateral projects and any related storage development will depend on market development.

On October 1, 2009, Empire posted an Open Season for an expansion project that will provide at least 200,000 Dth/day of incremental firm transportation capacity from anticipated Marcellus production at new and existing interconnection(s) along its recently completed Empire Connector line and along a proposed 16-mile 24" pipeline extension into Tioga County, Pennsylvania. Empire's preliminary cost estimate for the Tioga County Extension Project is approximately $43 million. This project would enable Marcellus producers to deliver their gas at existing Empire interconnections with Millennium Pipeline at Corning, New York, with TransCanada Pipeline at Chippawa, and with utility and power generation markets along its path, as well as to a planned new interconnection with Tennessee Gas Pipeline's 200 Line (Zone 5) in Ontario County, New York. Empire completed a non-binding Open Season on October 23, 2009 for capacity in the Tioga County Extension Project, and is in the process of negotiating binding precedent agreements with shippers who participated in the Open Season, representing more than adequate capacity to support the project facilities. Following successful negotiations, Empire will file an NGA Section 7(c) application with the FERC for approval of this project, and anticipates that these facilities will be placed in-service on or after September 1, 2011. The forecasted expenditures for this project over the next two years are as follows: $2.0 million in 2010 and $41.0 million in 2011. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. As of September 30, 2009, no preliminary survey and investigation charges had been expended on this project, but those activities began in October of 2009 and will be fully reserved in the periods they occur. The timeline associated with the Tioga County Extension Project will depend on the completion of shipper precedent agreements.

The Company anticipates financing the Line N Expansion Project, the Lamont Project, Phase I and Phase II of the W2E/Appalachian Lateral project, the storage expansion project, and the Tioga County Extension Project, all of which are discussed above, with a combination of cash from operations, short-term debt, and long-term debt.

Exploration and Production

Estimated capital expenditures in 2010 for the Exploration and Production segment include approximately $14.0 million for the Gulf Coast region, substantially all of which is for the off-shore program in the Gulf of Mexico, $17.0 million for the West Coast region and $224.0 million for the Appalachian region. The Company anticipates drilling 55 to 75 gross wells in the Marcellus Shale during 2010.

Estimated capital expenditures in 2011 for the Exploration and Production segment include approximately $5.0 million for the Gulf Coast region, substantially all of which is for the off-shore program in the Gulf of

Mexico, $27.0 million for the West Coast region and $385.0 million for the Appalachian region. The Company anticipates drilling 100 to 130 gross wells in the Marcellus Shale during 2011.

Estimated capital expenditures in 2012 for the Exploration and Production segment include approximately $12.0 million for the Gulf Coast region, substantially all of which is for the off-shore program in the Gulf of Mexico, $41.0 million for the West Coast region and $444.0 million for the Appalachian region. The Company anticipates drilling 120 to 150 gross wells in the Marcellus Shale during 2012.

All Other and Corporate

Estimated capital expenditures in 2010 for the All Other and Corporate category will primarily be for the construction of anticipated gathering systems, including the construction of Midstream Corporation's Covington Gathering System, as discussed below.

NFG Midstream Covington, LLC, a wholly owned subsidiary of Midstream Corporation, is constructing a gathering system in Tioga County, Pennsylvania. The project, called the Covington Gathering System, is to be constructed in two phases. The first phase was completed and placed in service in November 2009. The second phase is anticipated to be placed in service in 2010. When completed, the system will consist of approximately 15 miles of gathering system at a cost of $15 million to $18 million. As of September 30, 2009, the Company has spent approximately $8.1 million in costs related to this project.

NFG Midstream Processing, LLC, another wholly owned subsidiary of Midstream Corporation, has a 35% ownership in the Whitetail Processing Plant. The plant is currently under construction with completion expected in the fall of 2009. The total project cost is estimated at $4 million. Once completed, the plant will extract natural gas liquids from local production. As of September 30, 2009, the Company invested $1.3 million related to the construction of the plant.

The Company anticipates funding the Midstream Corporation projects with cash from operations and/or short-term borrowings.

The Company continuously evaluates capital expenditures and investments in corporations, partnerships, and other business entities. 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

The Company did not have any outstanding short-term notes payable to banks or commercial paper at September 30, 2009. However, 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, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $420.0 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, or replaced by similar lines. The total amount available to be issued under the Company's commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million that extends through September 30, 2010.

Under the Company's committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through September 30, 2010. At September 30, 2009, the Company's debt to capitalization ratio (as calculated under the facility) was .44. The constraints specified in the committed credit facility would permit an additional $1.7 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio would exceed .65. 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 credit facility, uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations. At September 30, 2009, the Company's long-term debt ratings were: BBB (S&P), Baa1 (Moody's Investor Service), and A- (Fitch Ratings Service). At September 30, 2009, the Company's commercial paper ratings were: A-2 (S&P), P-2 (Moody's Investor Service), and F2 (Fitch Ratings Service).

Under the Company's existing indenture covenants, at September 30, 2009, the Company would have been permitted to issue up to a maximum of $435.0 million in additional long-term unsecured indebtedness at then current market interest rates 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. However, if the Company were to experience another impairment of oil and gas properties in the future, it is possible that these indenture covenants would restrict the Company's ability to issue additional long-term unsecured indebtedness. This would not preclude the Company from issuing new indebtedness to replace maturing debt.

The Company's 1974 indenture, pursuant to which $99.0 million (or 7.9%) of the Company's long-term debt (as of September 30, 2009) 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 $300.0 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 fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more, or (ii) an event occurs that causes, or would permit the holders of 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, 2009, the Company had no debt outstanding under the committed credit facility.

The Company's embedded cost of long-term debt was 6.95% at September 30, 2009 and 6.5% at September 30, 2008. Refer to "Interest Rate Risk" in this Item for a more detailed breakdown of the Company's embedded cost of long-term debt.

In April 2008, the Company issued $300.0 million of 6.50% senior, unsecured notes in a private placement exempt from registration under the Securities Act of 1933. In February 2009, the Company exchanged the notes for economically identical notes registered under the Securities Act of 1933. The notes have a term of 10 years, with a maturity date in April 2018. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. The Company used $200.0 million of the proceeds of the issuance to refund $200.0 million of 6.303% medium-term notes that matured on May 27, 2008.

In April 2009, the Company issued $250.0 million of 8.75% notes due in March 2019. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $247.8 million. These notes were registered under the Securities Act of 1933. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including to replenish cash that was used to pay the $100 million due at the maturity of the Company's 6.0% medium-term notes on March 1, 2009. After this debt issuance, the Company's embedded cost of long-term debt increased from 6.5% to 6.95%. If the Company were to issue long-term debt today, its borrowing costs might be expected to be in the range of 6.0% to 7.0% depending on their maturity date.

On December 8, 2005, the Company's Board of Directors authorized the Company to implement a share repurchase program, whereby the Company could repurchase outstanding shares of common stock, up to an aggregate amount of eight million shares in the open market or through privately negotiated transactions. The Company completed the repurchase of the eight million shares during 2008 for a total program cost of $324.2 million (of which 4,165,122 shares were repurchased during the year ended September 30, 2008 for $191.0 million). In September 2008, the Company's Board of Directors authorized the repurchase of an additional eight million shares of the Company's common stock. Under this new authorization, the Company repurchased 1,028,981 shares for $46.0 million through September 17, 2008. The Company, however, stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. Such repurchases may resume in the future. The share repurchases mentioned above were funded with cash provided by operating activities and/or through the use of the Company's lines of credit.

The Company may issue debt or equity securities in a public offering or a private placement from time to time. 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 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 $27.8 million. These leases have been entered into for the use of buildings, vehicles, construction tools, meters and other items and are accounted for as operating leases.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2009, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2010	2011	2012	2013	2014	Thereafter	Total
				(Millions)			
Long-Term Debt, including interest expense(1)	$ 86.9	$274.0	$213.2	$304.2	$48.7	$888.5	$1,815.5
Operating Lease Obligations	$ 5.4	$ 3.9	$ 3.3	$ 2.4	$ 2.3	$ 10.5	$ 27.8
Purchase Obligations:							
Gas Purchase Contracts(2)	$478.0	$ 63.0	$ 29.2	$ 6.7	$ 6.7	$ 49.3	$ 632.9
Transportation and Storage Contracts	$ 42.2	$ 38.8	$ 37.4	$ 33.5	$33.1	$ 27.0	$ 212.0
Other	$ 25.1	$ 9.0	$ 4.1	$ 3.4	$ 3.3	$ 12.0	$ 56.9

(1) Refer to Note E — Capitalization and Short-Term Borrowings, as well as the table under Interest Rate Risk in the Market Risk Sensitive Instruments section below, for the amounts excluding interest expense.

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

The Company has other long-term obligations recorded on its Consolidated Balance Sheets that are not reflected in the table above. Such long-term obligations include pension and other post-retirement liabilities, asset retirement obligations, deferred income tax liabilities, various regulatory liabilities, derivative financial instrument liabilities and other deferred credits (the majority of which consist of liabilities for a non-qualified benefit plan, deferred compensation liabilities, environmental liabilities, workers compensation liabilities and liabilities for income tax uncertainties).

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 Sheets in accordance with the authoritative guidance (see Item 7, MD&A under the heading "Critical Accounting Estimates — 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 Sheets as a current liability; and (iii) other obligations which are reflected on the Consolidated Balance Sheets. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them in the table above.

OTHER MATTERS

In addition to the environmental and other matters discussed in this Item 7 and in Item 8 at Note I — Commitments and Contingencies, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to 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 a majority of the Company's employees. 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 2009, the Company contributed $16.0 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2010 will be in the range of $20.0 million to $30.0 million. It is likely that the Company will have to fund larger amounts to the Retirement Plan subsequent to 2010 in order to be in compliance with the Pension Protection Act of 2006. The Company expects that all subsidiaries having 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 (other post-retirement benefits) for a majority of its retired employees. The Company has established VEBA trusts and 401(h) accounts for its other post-retirement benefits. The Company has been making contributions to its VEBA trusts and 401(h) accounts over the last several years and anticipates that it will continue making contributions to the VEBA trusts and 401(h) accounts. During 2009, the Company contributed $25.5 million to its VEBA trusts and 401(h) accounts. The Company anticipates that the annual contribution to its VEBA trusts and 401(h) accounts in 2010 will be in the range of $25.0 million to $30.0 million. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.

As of September 30, 2009, the Company recorded a deferred tax asset relating to a federal net operating loss carryover of $25.1 million. This carryover, which is available as a result of an acquisition, expires in varying amounts between 2023 and 2029. Although this loss carryover is subject to certain annual limitations, no valuation allowance was recorded because of management's determination that the amount will be fully utilized during the carryforward period.

MARKET RISK SENSITIVE INSTRUMENTS

Energy Commodity Price Risk

The Company, in its Exploration and Production segment, Energy Marketing segment and Pipeline and Storage segment, uses various derivative financial instruments (derivatives), including price swap agreements 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, 2009 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.

Beginning in fiscal 2009, the Company adopted the authoritative guidance for fair value measurements. In accordance with the adoption of this guidance, the Company has identified certain inputs used to recognize fair value as Level 3 (unobservable inputs). The Level 3 derivative assets relate to oil swap agreements used to hedge forecasted sales at a specific location (southern California). The Company's internal model that is used to calculate fair value applies a historical basis differential (between the sales locations and NYMEX) to a forward NYMEX curve because there is not a forward curve specific to this sales location. Given the high level of historical correlation between NYMEX prices and prices at this sales location, the Company does not believe that the fair value recorded by the Company would be significantly different from what it expects to receive upon settlement. The fair value of the Level 3 derivative assets was reduced by $0.7 million based upon the Company's assessment of counterparty credit risk. The Company applied default probabilities to the anticipated cash flows that it was expecting from its counterparties to calculate the credit reserve.

The Level 3 assets amount to $27.0 million at September 30, 2009 and represent 60.2% of the Derivative Financial Instruments Assets or 5.9% of the Total Assets as shown in Item 8 at Note F — Fair Value Measurements at September 30, 2009.

During fiscal 2009, the Company transferred $8.1 million of derivative assets from Level 3 assets to Level 2 assets. The majority of these assets related to natural gas swaps on southern California natural gas production. The Company also transferred $0.8 million of derivative liabilities from Level 3 liabilities to Level 2 liabilities. These liabilities related to certain natural gas swaps on Gulf of Mexico natural gas production. These transfers occurred because the Company was able to obtain and utilize forward-looking, observable basis differential information for the hedges at these locations.

The Company uses the crude oil swaps classified as Level 3 to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative assets (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of the existing guidance for derivative instruments and hedging activities.

The increase in the net fair value of the Level 3 positions from October 1, 2008 to September 30, 2009, as shown in Item 8 at Note F, was attributable to a significant decrease in the commodity price of crude oil during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at September 30, 2009.

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 various national natural gas publications or on the NYMEX. 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, 2009. At September 30, 2009, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2012.

Natural Gas Price Swap Agreements

	Expected Maturity Dates			
	2010	2011	2012	Total
Notional Quantities (Equivalent Bcf)	16.3	12.9	8.8	38.0
Weighted Average Fixed Rate (per Mcf)	$6.91	$7.22	$7.48	$7.15
Weighted Average Variable Rate (per Mcf)	$6.15	$7.34	$7.56	$6.88

Of the total Bcf above, 0.6 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $8.08 per Mcf. The remaining 37.4 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $7.13 per Mcf.

Crude Oil Price Swap Agreements

	Expected Maturity Dates			
	2010	2011	2012	Total
Notional Quantities (Equivalent bbls)	1,692,000	648,000	348,000	2,688,000
Weighted Average Fixed Rate (per bbl)	$ 74.59	$ 66.54	$ 62.95	$ 71.14
Weighted Average Variable Rate (per bbl)	$ 59.38	$ 62.63	$ 64.30	$ 60.80

At September 30, 2009, the Company would have received from its respective counterparties an aggregate of approximately $10.4 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have received from its respective counterparties an aggregate of approximately $27.0 million to terminate the crude oil price swap agreements outstanding at September 30, 2009.

At September 30, 2008, the Company had natural gas price swap agreements covering 15.1 Bcf at a weighted average fixed rate of $9.69 per Mcf. The Company also had crude oil price swap agreements covering 1,920,000 bbls at a weighted average fixed rate of $90.50 per bbl.

The following table discloses the net contract volume 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, 2009, the Company held no futures contracts with maturity dates extending beyond 2012.

Futures Contracts

	Expected Maturity Dates			
	2010	2011	2012	Total
Net Contract Volume Purchased (Sold) (Equivalent Bcf)	3.9	1.0	—(1)	4.9
Weighted Average Contract Price (per Mcf)	$6.72	$7.02	$8.15	$6.74
Weighted Average Settlement Price (per Mcf)	$6.42	$6.84	$8.77	$6.45

(1) The Energy Marketing segment has purchased 11 futures contracts (1 contract = 2,500 Dth) for 2012.

At September 30, 2009, the Company had long (purchased) futures contracts covering 11.6 Bcf of gas extending through 2012 at a weighted average contract price of $6.37 per Mcf and a weighted average settlement price of $6.07 per Mcf. They are accounted for as fair value hedges and are used by the Company's Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed to due to the fixed price gas sales commitments that it enters into with residential, commercial and industrial customers. The Company would have had to pay $3.5 million to terminate these futures contracts at September 30, 2009.

At September 30, 2009, the Company had short (sold) futures contracts covering 6.7 Bcf of gas extending through 2011 at a weighted average contract price of $7.37 per Mcf and a weighted average settlement price of $6.07 per Mcf. Of this amount, 5.8 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Energy Marketing segment. The remaining 0.9 Bcf is accounted for as fair value hedges used to hedge against falling prices, a risk to which the Energy Marketing segment is exposed to due to the fixed price gas purchase commitments that it enters into with its natural gas suppliers. The Company would have received $8.7 million to terminate these futures contracts at September 30, 2009.

At September 30, 2008, the Company had futures contracts covering 2.4 Bcf (net long position) at a weighted average contract price of $9.99 per Mcf.

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. 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 a quarterly basis monitors counterparty credit exposure. The majority of the Company's counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with ten counterparties. At September 30, 2009, the Company had derivative financial instruments that were in gain positions with eight of the counterparties. The Company had derivative financial instruments that were in loss positions with the other two counterparties. The Company had $26.6 million of credit exposure with one counterparty (which is rated A1 (Moody's Investor Service), A (S&P), and A+ (Fitch Ratings Service) as of September 30, 2009). On average for those financial instruments that were in a gain position, the Company had $1.8 million of credit exposure per counterparty with the other seven counterparties that were in a gain position. The Company had not received any collateral from the counterparties at September 30, 2009 since the Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral.

As of September 30, 2009, eight of the ten counterparties to the Company's outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk-related contingency feature. In the event the Company's credit rating increases or falls below a certain threshold (the lower of the S&P or Moody's Debt Rating), the available credit extended to the Company would either increase or decrease. A decline in the Company's credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company's outstanding derivative instrument contracts were in a liability position and the Company's credit rating declined, then additional hedging collateral deposits would be required. At September 30, 2009, these credit-risk related contingency features were not triggered since the Company had assets of $37.9 million related to derivative financial instruments with the eight counterparties.

For its exchange traded futures contracts, which are in an asset position, the Company had paid $0.8 million in hedging collateral as of September 30, 2009. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions (i.e. those positions that have been settled for cash) and margin requirements. (This is discussed in Note A under Hedging Collateral Deposits.)

Interest Rate Risk

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, 2009:

	Principal Amounts by Expected Maturity Dates						
	2010	2011	2012	2013	2014	Thereafter	Total
	(Dollars in millions)						
Long-Term Fixed Rate Debt	$—	$200.0	$150.0	$250.0	$—	$649.0	$1,249.0
Weighted Average Interest Rate Paid	—	7.5%	6.7%	5.3%	—	7.5%	7.0%
Fair Value of Long-Term Fixed Rate Debt = $1,347.4							

RATE AND REGULATORY 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

Customer delivery rates charged by Distribution Corporation's New York division were established in a rate order issued on December 21, 2007 by the NYPSC. The rate order approved a revenue increase of $1.8 million annually, together with a surcharge that would collect up to $10.8 million to recover expenses for implementation of an efficiency and conservation incentive program. The rate order further provided for a return on equity of 9.1%. In connection with the efficiency and conservation program, the rate order also adopted Distribution Corporation's proposed revenue decoupling mechanism. The revenue decoupling mechanism, like others, "decouples" revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized usage per customer. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation. The Company surcharges or credits any difference from the average weather normalized usage per customer account. The surcharge or credit is calculated to recover total margin for the most recent twelve-month period ending December 31, and is applied to customer bills annually, beginning March 1st.

On April 18, 2008, Distribution Corporation filed an appeal with Supreme Court, Albany County, seeking review of the rate order. The appeal contends that portions of the rate order should be invalidated because they fail to meet the applicable legal standard for agency decisions. Among the issues challenged by the Company are the reasonableness of the NYPSC's disallowance of expense items and the methodology used for calculating rate of return, which the appeal contends understated the Company's cost of equity. Briefs were filed and oral argument was held on October 14, 2009. The Company cannot predict the outcome of the appeal at this time.

On April 7, 2009, the Governor of the State of New York signed into law an amendment to the Public Service Law increasing the allowed utility assessment from the current rate of one-third of one percent to one percent of a utility's in-state gross operating revenue, together with a temporary surcharge equal, as applied, to an additional one percent of the utility's gross operating revenue. As a result of this amendment, Distribution Corporation's New York Division paid a total assessment of $26.2 million during fiscal 2009, of which $22.9 million was labeled as the temporary surcharge. The NYPSC, in a generic proceeding initiated for the purpose of implementing the amended law, has authorized the recovery, through rates, of the full cost of the increased assessment. The assessment is currently being applied to customer bills.

Pennsylvania Jurisdiction

Distribution Corporation currently does not have a rate case on file with the PaPUC. Distribution Corporation's current tariff in its Pennsylvania jurisdiction was last approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007.

Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. The rate settlement approved by the FERC on February 9, 2007 requires Supply Corporation to make a general rate filing to be effective December 1, 2011, and bars Supply Corporation from making a general rate filing before then, with some exceptions specified in the settlement.

Empire's new facilities (the Empire Connector project) were placed into service on December 10, 2008. As of that date, Empire became an interstate pipeline subject to FERC regulation, performing services under a FERC-approved tariff and at FERC-approved rates. The December 21, 2006 FERC order issuing Empire its Certificate of Public Convenience and Necessity requires Empire to file a cost and revenue study at the FERC, within three years after the in-service date, in conjunction with which Empire will either justify Empire's existing recourse rates or propose alternative rates.

ENVIRONMENTAL MATTERS

The Company is subject to various federal, state and local laws and regulations 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. 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. At September 30, 2009, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $18.7 million to $22.9 million. The minimum estimated liability of $18.7 million has been recorded on the Consolidated Balance Sheet at September 30, 2009. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet. Other than discussed in Note I (referred to below), the Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental regulations, new information or other factors could adversely impact the Company.

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

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussions. If enacted or adopted, legislation or regulation that restricts carbon emissions could increase the Company's cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. Proposed measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

NEW AUTHORITATIVE ACCOUNTING AND FINANCIAL REPORTING GUIDANCE

In September 2006, the FASB issued authoritative guidance for using fair value to measure assets and liabilities. This guidance serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. This guidance is to be applied whenever assets or liabilities are to be measured at fair value. On October 1, 2008, the Company adopted this guidance for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis. This guidance delays the effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value on a recurring basis, until the Company's first quarter of fiscal 2010. For further discussion of the impact of the adoption of the authoritative guidance for financial assets and financial liabilities, refer to Item 8 at Note F — Fair Value Measurements. The Company is currently evaluating the impact that the adoption of the authoritative guidance for nonfinancial assets and nonfinancial liabilities will have on its consolidated financial statements. The Company has identified Goodwill as being the major nonfinancial asset that may be impacted by the adoption of this guidance. The Company does not believe there are any nonfinancial liabilities that will be impacted by the adoption of this guidance.

In September 2006, the FASB issued authoritative guidance which requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. This guidance requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. This guidance also specifies that a plan's assets and obligations that determine its funded status be measured as of the end of the Company's fiscal year, with limited exceptions. In accordance with this authoritative guidance, the Company has recognized the funded status of its benefit plans and implemented the related disclosure requirements at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company's fiscal year-end date was fully adopted by the Company as of September 30, 2009. The Company has historically measured its plan assets and benefit obligations using a June 30th measurement date. As a result of the change to a September 30th measurement date, the Company recorded fifteen months of pension and other post-retirement benefit costs during fiscal 2009. Such costs were calculated using June 30, 2008 measurement date data. Three of those months pertain to the period of July 1, 2008 to September 30, 2008. The pension and other post-retirement benefit costs for that period amounted to

$5.1 million and were recorded by the Company during the quarter ended December 31, 2008 as a $3.8 million increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a $1.3 million ($0.8 million after tax) adjustment to earnings reinvested in the business. Refer to Item 8 at Note H — Retirement Plan and Other Post-Retirement Benefits for further disclosures regarding the impact of this authoritative guidance on the Company's consolidated financial statements.

In December 2007, the FASB revised authoritative guidance that significantly changes the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under this guidance, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. This guidance is effective as of the Company's first quarter of fiscal 2010.

In December 2007, the FASB issued authoritative guidance that changes the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. This authoritative guidance is effective as of the Company's first quarter of fiscal 2010. The Company currently does not have any NCI.

In March 2008, the FASB issued authoritative guidance that requires entities to provide enhanced disclosures related to an entity's derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity's financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under authoritative guidance for derivative instruments and hedging activities, and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. The Company adopted the disclosure provisions of this authoritative guidance during the Company's second quarter of fiscal 2009. Refer to Item 8 at Note G — Financial Instruments for these disclosures.

In June 2008, the FASB issued authoritative guidance concerning whether certain instruments granted in share-based payment transactions are participating securities. This guidance specified that unvested share-based payment awards that contain nonforfeitable rights to dividends are participating securities and shall be included in the computation of earnings per share pursuant to the "two-class" method. The "two-class" method allocates undistributed earnings between common shares and participating securities. This authoritative guidance is effective as of the Company's first quarter of fiscal 2010. The Company does not believe this guidance will have a material impact on its earnings per share calculation.

On December 31, 2008, the SEC issued a final rule on Modernization of Oil and Gas Reporting. The final rule modifies the SEC's reporting and disclosure rules for oil and gas reserves and aligns the full cost accounting rules with the revised disclosures. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements are effective for the Company's Form 10-K for the period ended September 30, 2010. Early adoption is not permitted. The Company is currently evaluating the impact that adoption of these rules will have on its consolidated financial statements and MD&A disclosures.

In March 2009, the FASB issued authoritative guidance that expands the disclosures required in an employer's financial statements about pension and other post-retirement benefit plan assets. The additional disclosures include more details on how investment allocation decisions are made, the plan's investment policies and strategies, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period, and disclosure regarding significant concentrations of risk within plan assets. The additional disclosure requirements are required for the Company's Form 10-K for the period ended

September 30, 2010. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statement disclosures.

Effective with the June 30, 2009 Form 10-Q, the Company adopted the FASB authoritative guidance for subsequent events that establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Refer to Item 8 at Note R — Subsequent Events for disclosures made as a result of the adoption of this guidance.

In June 2009, the FASB issued authoritative guidance that establishes the FASB Accounting Standards Codification™ (the Codification) as the source of authoritative GAAP recognized by the FASB to be applied by all nongovernmental entities in the preparation of financial statements in conformity with GAAP. Rules and interpretive releases of the SEC under authority of federal securities law are also sources of authoritative GAAP for SEC registrants. All other nongrandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. The Codification was effective for interim and annual periods ending after September 15, 2009. Effective with this September 30, 2009 Form 10-K, the Company has updated its disclosures to conform to the Codification. There has been no impact on the Company's consolidated financial statements as the Codification does not change or alter existing GAAP.

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, statements regarding future prospects, plans, objectives, goals, projections, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may," 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. Financial and economic conditions, including the availability of credit, and their effect on the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments;

2. Occurrences affecting the Company's ability to obtain financing under credit lines or other credit facilities or through the issuance of commercial paper, other short-term notes or debt or equity securities, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions;

3. Changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers' ability to pay for, the Company's products and services;

4. The creditworthiness or performance of the Company's key suppliers, customers and counterparties;

5. Economic disruptions or uninsured losses resulting from terrorist activities, acts of war, major accidents, fires, hurricanes, other severe weather, pest infestation or other natural disasters;

6. Changes in actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;

7. Changes in demographic patterns and weather conditions;

8. Changes in the availability and/or price of natural gas or oil and the effect of such changes on the accounting treatment of derivative financial instruments or the valuation of the Company's natural gas and oil reserves;

9. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;

10. Uncertainty of oil and gas reserve estimates;

11. Factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, and the need to obtain governmental approvals and permits and comply with environmental laws and regulations;

12. Significant differences between the Company's projected and actual production levels for natural gas or oil;

13. Changes in the availability and/or price of derivative financial instruments;

14. Changes in the price differentials between oil having different quality and/or different geographic locations, or changes in the price differentials between natural gas having different heating values and/or different geographic locations;

15. Inability to obtain new customers or retain existing ones;

16. Significant changes in competitive factors affecting the Company;

17. Changes in laws and regulations to which the Company is subject, including tax, environmental, safety and employment laws and regulations;

18. Governmental/regulatory actions, initiatives and proceedings, including those involving acquisitions, financings, rate cases (which address, among other things, allowed rates of return, rate design and retained natural gas), affiliate relationships, industry structure, franchise renewal, and environmental/safety requirements;

19. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;

20. Significant differences between the Company's projected and actual capital expenditures and operating expenses, and unanticipated project delays or changes in project costs or plans;

21. The nature and projected profitability of pending and potential projects and other investments, and the ability to obtain necessary governmental approvals and permits;

22. Ability to successfully identify and finance acquisitions or other investments and ability to operate and integrate existing and any subsequently acquired business or properties;

23. Significant changes in tax rates or policies or in rates of inflation or interest;

24. 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;

25. Changes in accounting principles or the application of such principles to the Company;

26. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;

27. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or

28. 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 O — Quarterly Financial Data (unaudited) and Note Q — Supplementary Information for Oil and Gas Producing Activities (unaudited), 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2009 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Buffalo, New York
November 25, 2009

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

	2009	2008	2007
	Year Ended September 30 (Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$ 2,057,852	$ 2,400,361	$ 2,039,566
Operating Expenses			
Purchased Gas	1,001,782	1,235,157	1,018,081
Operation and Maintenance	402,856	432,871	396,408
Property, Franchise and Other Taxes	72,163	75,585	70,660
Depreciation, Depletion and Amortization	173,410	170,623	157,919
Impairment of Oil and Gas Producing Properties	182,811	—	—
	1,833,022	1,914,236	1,643,068
Operating Income	224,830	486,125	396,498
Other Income (Expense):			
Income from Unconsolidated Subsidiaries	3,366	6,303	4,979
Impairment of Investment in Partnership	(1,804)	—	—
Other Income	6,576	7,376	4,936
Interest Income	5,776	10,815	1,550
Interest Expense on Long-Term Debt	(79,419)	(70,099)	(68,446)
Other Interest Expense	(7,497)	(3,870)	(6,029)
Income from Continuing Operations Before Income Taxes	151,828	436,650	333,488
Income Tax Expense	51,120	167,922	131,813
Income from Continuing Operations	100,708	268,728	201,675
Discontinued Operations:			
Income from Operations, Net of Tax	—	—	15,479
Gain on Disposal, Net of Tax	—	—	120,301
Income from Discontinued Operations, Net of Tax	—	—	135,780
Net Income Available for Common Stock	100,708	268,728	337,455
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	953,799	983,776	786,013
	1,054,507	1,252,504	1,123,468
Share Repurchases	—	(194,776)	(38,196)
Cumulative Effect of Adoption of Authoritative Guidance for Income Taxes	—	(406)	—
Adoption of Authoritative Guidance for Defined Benefit Pension and Other Post-Retirement Plans	(804)	—	—
Dividends on Common Stock	(105,410)	(103,523)	(101,496)
Balance at End of Year	$ 948,293	$ 953,799	$ 983,776
Earnings Per Common Share:			
Basic:			
Income from Continuing Operations	$ 1.26	$ 3.27	$ 2.43
Income from Discontinued Operations	—	—	1.63
Net Income Available for Common Stock	$ 1.26	$ 3.27	$ 4.06
Diluted:			
Income from Continuing Operations	$ 1.25	$ 3.18	$ 2.37
Income from Discontinued Operations	—	—	1.59
Net Income Available for Common Stock	$ 1.25	$ 3.18	$ 3.96
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	79,649,965	82,304,335	83,141,640
Used in Diluted Calculation	80,628,685	84,474,839	85,301,361

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30 2009	At September 30 2008
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$5,183,527	$4,873,969
Less — Accumulated Depreciation, Depletion and Amortization	2,051,482	1,719,869
	3,132,045	3,154,100
Current Assets		
Cash and Temporary Cash Investments	408,053	68,239
Cash Held in Escrow	2,000	—
Hedging Collateral Deposits	848	1
Receivables — Net of Allowance for Uncollectible Accounts of $38,334 and $33,117, Respectively	144,466	185,397
Unbilled Utility Revenue	18,884	24,364
Gas Stored Underground	55,862	87,294
Materials and Supplies — at average cost	24,520	31,317
Unrecovered Purchased Gas Costs	—	37,708
Other Current Assets	68,474	65,158
Deferred Income Taxes	53,863	—
	776,970	499,478
Other Assets		
Recoverable Future Taxes	138,435	82,506
Unamortized Debt Expense	14,815	13,978
Other Regulatory Assets	530,913	189,587
Deferred Charges	2,737	4,417
Other Investments	78,503	80,640
Investments in Unconsolidated Subsidiaries	16,257	16,279
Goodwill	5,476	5,476
Intangible Assets	21,536	26,174
Prepaid Post-Retirement Benefit Costs	—	21,034
Fair Value of Derivative Financial Instruments	44,817	28,786
Other	6,625	7,732
	860,114	476,609
Total Assets	$4,769,129	$4,130,187
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized — 200,000,000 Shares; Issued and Outstanding — 80,499,915 Shares and 79,120,544 Shares, Respectively	$ 80,500	$ 79,121
Paid In Capital	602,839	567,716
Earnings Reinvested in the Business	948,293	953,799
Total Common Shareholders' Equity Before Items Of Other Comprehensive Income (Loss)	1,631,632	1,600,636
Accumulated Other Comprehensive Income (Loss)	(42,396)	2,963
Total Comprehensive Shareholders' Equity	1,589,236	1,603,599
Long-Term Debt, Net of Current Portion	1,249,000	999,000
Total Capitalization	2,838,236	2,602,599
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	—	100,000
Accounts Payable	90,723	142,520
Amounts Payable to Customers	105,778	2,753
Dividends Payable	26,967	25,714
Interest Payable on Long-Term Debt	32,031	22,114
Customer Advances	24,555	33,017
Customer Security Deposits	17,430	14,047
Other Accruals and Current Liabilities	18,875	31,173
Deferred Income Taxes	—	1,871
Fair Value of Derivative Financial Instruments	2,148	1,362
	318,507	374,571
Deferred Credits		
Deferred Income Taxes	663,876	634,372
Taxes Refundable to Customers	67,046	18,449
Unamortized Investment Tax Credit	3,989	4,691
Cost of Removal Regulatory Liability	105,546	103,100
Other Regulatory Liabilities	120,229	91,933
Pension and Other Post-Retirement Liabilities	415,888	78,909
Asset Retirement Obligations	91,373	93,247
Other Deferred Credits	144,439	128,316
	1,612,386	1,153,017
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$4,769,129	$4,130,187

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2009	2008	2007
	(Thousands of dollars)		
Operating Activities			
Net Income Available for Common Stock	$ 100,708	$ 268,728	$ 337,455
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Gain on Sale of Discontinued Operations	—	—	(159,873)
Impairment of Oil and Gas Producing Properties	182,811	—	—
Depreciation, Depletion and Amortization	173,410	170,623	170,803
Deferred Income Taxes	(2,521)	72,496	52,847
Income from Unconsolidated Subsidiaries, Net of Cash Distributions	(466)	1,977	(3,366)
Impairment of Investment in Partnership	1,804	—	—
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(5,927)	(16,275)	(13,689)
Other	17,443	4,858	16,399
Change in:			
Hedging Collateral Deposits	(847)	4,065	15,610
Receivables and Unbilled Utility Revenue	47,658	(16,815)	5,669
Gas Stored Underground and Materials and Supplies	43,598	(22,116)	(5,714)
Unrecovered Purchased Gas Costs	37,708	(22,939)	(1,799)
Prepayments and Other Current Assets	2,921	(36,376)	18,800
Accounts Payable	(61,149)	32,763	(26,002)
Amounts Payable to Customers	103,025	(7,656)	(13,526)
Customer Advances	(8,462)	10,154	(6,554)
Customer Security Deposits	3,383	609	1,907
Other Accruals and Current Liabilities	13,676	(4,250)	7,043
Other Assets	(35,140)	(11,887)	4,109
Other Liabilities	(4,201)	54,817	(5,922)
Net Cash Provided by Operating Activities	609,432	482,776	394,197
Investing Activities			
Capital Expenditures	(309,930)	(397,734)	(276,728)
Investment in Subsidiary, Net of Cash Acquired	(34,933)	—	—
Investment in Partnerships	(1,317)	—	(3,300)
Net Proceeds from Sale of Foreign Subsidiaries	—	—	232,092
Cash Held in Escrow	(2,000)	58,397	(58,248)
Net Proceeds from Sale of Oil and Gas Producing Properties	3,643	5,969	5,137
Other	(2,806)	4,376	(725)
Net Cash Used in Investing Activities	(347,343)	(328,992)	(101,772)
Financing Activities			
Excess Tax Benefits Associated with Stock-Based Compensation Awards	5,927	16,275	13,689
Shares Repurchased under Repurchase Plan	—	(237,006)	(48,070)
Net Proceeds from Issuance of Long-Term Debt	247,780	296,655	—
Reduction of Long-Term Debt	(100,000)	(200,024)	(119,576)
Net Proceeds from Issuance of Common Stock	28,176	17,432	17,498
Dividends Paid on Common Stock	(104,158)	(103,683)	(100,632)
Net Cash Provided By (Used in) Financing Activities	77,725	(210,351)	(237,091)
Effect of Exchange Rates on Cash	—	—	(139)
Net Increase (Decrease) in Cash and Temporary Cash Investments	339,814	(56,567)	55,195
Cash and Temporary Cash Investments At Beginning of Year	68,239	124,806	69,611
Cash and Temporary Cash Investments At End of Year	$ 408,053	$ 68,239	$ 124,806
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			
Interest	$ 75,640	$ 69,841	$ 75,987
Income Taxes	$ 40,638	$ 103,154	$ 97,961

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2009	2008	2007
	(Thousands of dollars)		
Net Income Available for Common Stock	$ 100,708	$268,728	$337,455
Other Comprehensive Income (Loss), Before Tax:			
Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(71,771)	(13,584)	—
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	1,008	1,924	—
Foreign Currency Translation Adjustment	(33)	12	7,874
Reclassification Adjustment for Realized Foreign Currency Translation Gain in Net Income	—	—	(42,658)
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(6,118)	(4,856)	4,747
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	119,210	(31,490)	8,495
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(114,380)	64,645	5,106
Other Comprehensive Income (Loss), Before Tax	(72,084)	16,651	(16,436)
Income Tax Benefit Related to the Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(27,082)	(5,127)	—
Reclassification Adjustment for Income Tax Benefit Related to the Amortization of the Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	380	726	—
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(2,311)	(1,434)	1,724
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	48,293	(13,228)	3,153
Reclassification Adjustment for Income Tax (Expense) Benefit on Realized (Gains) Losses on Derivative Financial Instruments In Net Income	(46,005)	26,548	2,824
Income Taxes — Net	(26,725)	7,485	7,701
Other Comprehensive Income (Loss)	(45,359)	9,166	(24,137)
Comprehensive Income	$ 55,349	$277,894	$313,318

See Notes to Consolidated Financial Statements

Note A — Summary of Significant Accounting Policies

Principles of Consolidation

The Company consolidates its majority owned entities. The equity method is used to account for minority owned entities. All significant intercompany balances and transactions are eliminated. The Company uses proportionate consolidation when accounting for drilling arrangements related to oil and gas producing properties accounted for under the full cost method of accounting.

The preparation of the consolidated financial statements in conformity with GAAP 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.

Regulation

The Company is subject to regulation by certain state and federal authorities. The Company has accounting policies which conform to GAAP, 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 C — Regulatory Matters for further discussion.

Revenue Recognition

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 Energy Marketing segment records revenue as bills are rendered for service supplied on a calendar month basis.

The Company's Pipeline and Storage segment records revenue for natural gas transportation and storage services. Revenue from reservation charges on firm contracted capacity is recognized through equal monthly charges over the contract period regardless of the amount of gas that is transported or stored. Commodity charges on firm contracted capacity and interruptible contracts are recognized as revenue when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage field. The point of delivery into the pipeline or injection or withdrawal from storage is the point at which ownership and risk of loss transfers to the buyer of such transportation and storage services.

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.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts is the Company's best estimate of the amount of probable credit losses in the existing accounts receivable. The allowance is determined based on historical experience, the age and other specific information about customer accounts. Account balances are charged off against the allowance twelve months after the account is final billed or when it is anticipated that the receivable will not be recovered.

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 C — Regulatory Matters for further discussion.

The impact of weather on revenues in the Utility segment's New York rate jurisdiction is tempered by a 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 warmer than normal results in a surcharge being added to customers' current bills, while weather that is 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.

The impact of weather normalized usage per customer account in the Utility segment's New York rate jurisdiction is tempered by a revenue decoupling mechanism. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation. Weather normalized usage per account that exceeds the average weather normalized usage per customer account results in a refund being credited to customers' bills. Weather normalized usage per account that is below the average weather normalized usage per account results in a surcharge being added to customers' bills. The surcharge or credit is calculated over a twelve-month period ending December 31st, and applied to customer bills annually, beginning March 1st.

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, including return on equity and income taxes, through fixed monthly reservation charges. Because of this rate design, changes in throughput due to weather variations do not have a significant impact on the revenues of Supply Corporation.

Prior to December 10, 2008, the allowed rates that Empire billed its customers were based on a modified fixed-variable rate design, which recovered return on equity and income taxes through variable charges. Because of this rate design, changes in throughput due to weather variations could have had a significant impact on Empire's revenues. On December 10, 2008, Empire became FERC regulated. As a result, Empire now bills its customers based on a straight fixed-variable rate design. Changes in throughput due to weather variations no longer have a significant impact on Empire's revenue.

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.

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 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 does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on 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 cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, 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 tax effects related to the differences between the book and tax basis of the properties. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2009, 2008, and 2007, estimated future net cash flows were increased by $143.3 million, $34.5 million and $2.2 million, respectively. The Company's capitalized costs exceeded the full cost ceiling for the Company's oil and gas properties at December 31, 2008. As such, the Company recognized a pre-tax impairment of $182.8 million at December 31, 2008. Deferred income taxes of $74.6 million were recorded associated with this impairment.

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 unproved oil and gas properties is excluded from this computation. In the All Other category, 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	
	2009	2008
	(Thousands)	
Utility	$1,616,908	$1,580,366
Pipeline and Storage	1,196,937	996,743
Exploration and Production	1,972,353	1,800,422
Energy Marketing	1,241	1,232
All Other and Corporate	154,512	146,005
	$4,941,951	$4,524,768

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2009	2008	2007
Utility	2.6%	2.6%	2.8%
Pipeline and Storage	3.0%	3.2%	3.5%
Exploration and Production, per Mcfe(1)	$2.14	$2.26	$1.94
Energy Marketing	3.4%	3.5%	2.8%
All Other and Corporate	5.2%	4.3%	4.1%

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note Q — Supplementary Information for Oil and Gas Producing Properties, depletion of oil and gas producing properties amounted to $2.10, $2.23 and $1.92 per Mcfe of production in 2009, 2008 and 2007, respectively. Depletion of oil and gas producing properties in the United States amounted to $2.10, $2.23 and $1.97 per Mcfe of production in 2009, 2008 and 2007, respectively. Depletion of oil and gas producing properties in Canada amounted to $1.67 per Mcfe of production in 2007.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2009 and 2008 on its Consolidated Balance Sheets related to the Company's acquisition of Empire in 2003. The Company accounts for goodwill in accordance with the current authoritative guidance, which requires the Company to test goodwill for impairment annually. At September 30, 2009 and 2008, the fair value of Empire was greater than its book value. As such, the goodwill was considered not impaired.

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 G — 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 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. Reference is made to Note F — Fair Value Measurements for further discussion concerning the fair value of derivative financial 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. 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, purchased gas expense or interest expense on the Consolidated Statements of Income. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statements of Income. In December 2006, the Company repaid $22.8 million of Empire's secured debt. The interest costs of this secured debt were hedged by an interest rate collar. Since the hedged transaction was settled and there will be no future cash flows associated with the secured debt, hedge accounting for the interest rate collar was discontinued and the unrealized gain of $1.9 million in accumulated other comprehensive income associated with the interest rate collar was reclassified to the Consolidated Statement of Income. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2009 or 2008.

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 (see Other Current Assets section in this footnote). 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 2009, 2008 or 2007.

Accumulated Other Comprehensive Income (Loss)

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

	Year Ended September 30	
	2009	2008
	(Thousands)	
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$(63,802)	$(19,741)
Cumulative Foreign Currency Translation Adjustment	(104)	(71)
Net Unrealized Gain on Derivative Financial Instruments	18,491	15,949
Net Unrealized Gain on Securities Available for Sale	3,019	6,826
Accumulated Other Comprehensive Income (Loss)	$(42,396)	$ 2,963

At September 30, 2009, it is estimated that of the $18.5 million net unrealized gain on derivative financial instruments shown in the table above, $18.6 million of unrealized gains will be reclassified into the Consolidated Statement of Income during 2010. The remaining unrealized loss on derivative financial instruments of $0.1 million will be reclassified into the Consolidated Statement of Income in subsequent years. The Company's derivative financial instruments extend out to 2012.

The amounts included in accumulated other comprehensive income (loss) related to the funded status of the Company's pension and other post-retirement benefit plans consist of prior service costs and accumulated losses. The total amount for prior service costs was $0.3 million and $0.4 million at September 30, 2009 and September 30, 2008, respectively. The total amount for accumulated losses was $63.5 million and $19.3 million at September 30, 2009 and September 30, 2008, respectively.

Gas Stored Underground — Current

In the Utility segment, gas stored underground — current in the amount of $30.4 million is carried at lower of cost or market, on a LIFO method. Based upon the average price of spot market gas purchased in September 2009, 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 $51.6 million at September 30, 2009. All other gas stored underground — current, which is in the Energy Marketing segment, is carried at lower of cost or market on an average cost method.

Purchased Timber Rights

The Company purchases the right to harvest timber from land owned by other parties. These rights, which extend from several months to several years, are purchased to ensure an adequate supply of timber for the Company's sawmill and kiln operations. The historical value of timber rights expected to be harvested during the following year are included in Materials and Supplies on the Consolidated Balance Sheets while the historical value of timber rights expected to be harvested beyond one year are included in Other Assets on the Consolidated Balance Sheets. The components of the Company's purchased timber rights are as follows:

	Year Ended September 30	
	2009	2008
	(Thousands)	
Materials and Supplies	$ 6,349	$ 9,911
Other Assets	6,343	7,383
	$12,692	$17,294

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). With the sale of SECI on August 31, 2007, the Company eliminated its major foreign operation. While the Company is in the process of winding up or selling certain power development projects in Europe, the investment in such projects is not significant and the Company does not expect to have any significant foreign currency translation adjustments in the future.

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.

Consolidated Statements of Cash Flows

For purposes of the Consolidated Statements of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents.

At September 30, 2009, the Company accrued $9.1 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. The Company also accrued $0.7 million of capital expenditures in the All Other category related to the construction of the Midstream Covington Gathering System at September 30, 2009. These amounts were excluded from the Consolidated Statement of Cash Flows at September 30, 2009 since they represent non-cash investing activities at that date.

At September 30, 2008, the Company accrued $16.8 million of capital expenditures related to the construction of the Empire Connector project. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2008 since it represented a non-cash investing activity at that date. These capital expenditures were paid during the quarter ended December 31, 2008 and have been included in the Consolidated Statement of Cash Flows for the year ended September 30, 2009.

Hedging Collateral Account

This is an account title for cash held in margin accounts funded by the Company to serve as collateral for open hedging positions. At September 30, 2009, the Company had hedging collateral deposits of $0.8 million related to its exchange-traded futures contracts. It is the Company's policy to not offset hedging collateral deposits paid or received against the derivative financial instruments liability or asset balances.

Cash Held in Escrow

On July 20, 2009, the Company's wholly-owned subsidiary in the Exploration and Production segment, Seneca, acquired Ivanhoe Energy's United States oil and gas operations for approximately $39.2 million in cash (including cash acquired of $4.3 million). The cash acquired at acquisition includes $2 million held in escrow at September 30, 2009. Seneca placed this amount in escrow as part of the purchase price, and in accordance with the purchase agreement, this amount will remain in escrow for one year from the closing of the transaction provided there are no pending disputes or actions regarding obligations and liabilities required to be satisfied or discharged by Ivanhoe Energy.

On August 31, 2007, the Company received approximately $232.1 million of proceeds from the sale of SECI, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. The escrow account was a Canadian dollar denominated account. On a U.S. dollar basis, the value of this account was $62.0 million at September 30, 2007. In December 2007, the Canadian government issued the tax clearance certificate, thereby releasing the proceeds from restriction as of December 31, 2007. To hedge against foreign currency exchange risk related to the cash being held in escrow, the Company held a forward contract to sell Canadian dollars. For presentation purposes on the Consolidated Statement of Cash Flows, for the year ended September 30, 2008, the Cash Held in Escrow line item within Investing Activities reflects the net proceeds to the Company (received on January 8, 2008) after adjusting for the impact of the foreign currency hedge.

Other Current Assets

Other Current Assets consist of prepayments in the amounts of $12.2 million and $10.6 million at September 30, 2009 and 2008, respectively, prepaid property and other taxes of $12.0 million and $11.2 million at September 30, 2009 and 2008, respectively, federal income taxes receivable in the amounts of $23.3 million and $27.5 million at September 30, 2009 and 2008, respectively, state income taxes receivable in the amounts of $13.5 million and $5.0 million at September 30, 2009 and 2008, respectively, and fair values of firm commitments in the amounts of $7.5 million and $10.9 million at September 30, 2009 and 2008, respectively.

Customer Advances

The Company's Utility and Energy Marketing segments have balanced billing programs whereby customers pay their estimated annual usage in equal installments over a twelve-month period. Monthly payments under the balanced billing programs are typically higher than current month usage during the summer months. During the winter months, monthly payments under the balanced billing programs are typically lower than current month usage. At September 30, 2009 and 2008, customers in the balanced billing programs had advanced excess funds of $24.6 million and $33.0 million, respectively.

Customer Security Deposits

The Company, in its Utility, Pipeline and Storage, and Energy Marketing segments, often times requires security deposits from marketers, producers, pipeline companies, and commercial and industrial customers before providing services to such customers. At September 30, 2009 and 2008, the Company had received customer security deposits amounting to $17.4 million and $14.0 million, 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. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options and stock-settled SARs. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these stock options and stock-settled SARs as determined using the Treasury Stock Method. Stock options and stock-settled SARs that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2009, there were 365,000 stock-settled SARs and 765,000 stock options excluded as being antidilutive. For 2008, there were 7,344 stock-settled SARs excluded as being antidilutive, and there were no stock options excluded as being antidilutive. For 2007, no stock options or stock-settled SARs were excluded as being antidilutive.

Share Repurchases

The Company considers all shares repurchased as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. The repurchases are accounted for on the date the share repurchase is settled as an adjustment to common stock (at par value) with the excess repurchase price allocated between paid in capital and retained earnings. Refer to Note E — Capitalization and Short-Term Borrowings for further discussion of the share repurchase program.

Stock-Based Compensation

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, stock-settled SARs, restricted stock, performance units or performance shares. Stock options and stock-settled SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no stock option or stock-settled SAR is exercisable less than one year or more than ten years after the date of each grant. Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. 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. Restrictions on restricted stock awards generally lapse ratably over a period of not more than ten years after the date of each grant.

The Company follows authoritative guidance which requires the measurement and recognition of compensation cost at fair value for all share-based payments, including stock options and stock-settled SARs. The Company has chosen the Black-Scholes-Merton closed form model to calculate the compensation expense associated with such share-based payments since it is easier to administer than the Binomial option-pricing model. Furthermore, since the Company does not have complex stock-based compensation awards, it does not believe that compensation expense would be materially different under either model.

The Company did not grant any stock options during the years ended September 30, 2009 and 2008. There were 448,000 stock options granted during the year ended September 30, 2007. The Company granted 610,000 and 321,000 performance based stock-settled SARs during the year ended September 30, 2009 and 2008, respectively, but did not grant any performance based stock-settled SARs during the year ended September 30, 2007. The Company granted 50,000 non-performance based stock-settled SARs during the year ended September 30, 2007, but did not grant any non-performance based stock-settled SARs during the years ended September 30, 2009 and 2008. The accounting treatment for such performance based and non-performance based stock-settled SARs is the same as the accounting for stock options under the current authoritative guidance for stock-based compensation. The performance based stock-settled SARs granted for the year ended

September 30, 2009 vest and become exercisable annually in one-third increments, provided that a performance condition is met. The performance condition for each fiscal year, generally stated, is an increase over the prior fiscal year of at least five percent in certain oil and natural gas production of the Exploration and Production segment. The performance based stock-settled SARs granted for the year ended September 30, 2008 vest and become exercisable annually, in one-third increments, provided that a performance condition for diluted earnings per share is met for the prior fiscal year. The weighted average grant date fair value of the performance based stock-settled SARs granted during 2009 and 2008 was estimated on the date of grant using the same accounting treatment that is applied for stock options, and assumes that the performance conditions specified will be achieved. If such conditions are not met or it is not considered probable that such conditions will be met, no compensation expense is recognized and any previously recognized compensation expense is reversed. During 2009, the Company reversed $0.5 million of previously recognized compensation expense associated with performance based stock-settled SARs. The Company also granted 63,000, 25,000, and 25,000 restricted share awards (non-vested stock as defined by the current accounting literature) during the years ended September 30, 2009, 2008 and 2007, respectively.

Stock-based compensation expense for the years ended September 30, 2009, 2008 and 2007 was approximately $2.1 million (net of the $0.5 million reversal of compensation expense discussed above), $2.3 million, and $3.7 million, respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statement of Income. The total income tax benefit related to stock-based compensation expense during the years ended September 30, 2009, 2008 and 2007 was approximately $0.8 million, $0.9 million and $1.5 million, respectively. There were no capitalized stock-based compensation costs during the years ended September 30, 2009 and 2008.

Stock Options

The total intrinsic value of stock options exercised during the years ended September 30, 2009, 2008 and 2007 totaled approximately $18.7 million, $24.6 million, and $38.7 million, respectively. For 2009, 2008 and 2007, the amount of cash received by the Company from the exercise of such stock options was approximately $29.2 million, $18.5 million, and $26.0 million, respectively.

The Company realizes tax benefits related to the exercise of stock options on a calendar year basis as opposed to a fiscal year basis. As such, for stock options exercised during the quarters ended December 31, 2008, 2007, and 2006, the Company realized a tax benefit of $1.6 million, $4.4 million, and $3.2 million, respectively. For stock options exercised during the period of January 1, 2009 through September 30, 2009, the Company will realize a tax benefit of approximately $5.7 million in the quarter ended December 31, 2009. For stock options exercised during the period of January 1, 2008 through September 30, 2008, the Company realized a tax benefit of approximately $4.3 million in the quarter ended December 31, 2008. For stock options exercised during the period of January 1, 2007 through September 30, 2007, the Company realized a tax benefit of approximately $12.0 million in the quarter ended December 31, 2007. The weighted average grant date fair value of options granted in 2007 is $7.27 per share. As stated above, there were no stock options granted during the years ended September 30, 2009 and 2008. For the years ended September 30, 2009, 2008 and 2007, 27,000, 358,000 and 327,501 stock options became fully vested, respectively. The total fair value of the stock options that became vested during the years ended September 30, 2009, 2008 and 2007 was approximately $0.2 million, $2.6 million and $2.1 million, respectively. As of September 30, 2009, unrecognized compensation expense related to stock options totaled approximately $47,000, which will be recognized over a weighted average period of 3.0 months. For a summary of transactions during 2009 involving option shares for all plans, refer to Note E — Capitalization and Short-Term Borrowings.

The fair value of options at the date of grant was estimated using the Black-Scholes-Merton closed form model. The following weighted average assumptions were used in estimating the fair value of options at the date of grant:

	Year Ended September 30		
	2009	2008	2007
Risk Free Interest Rate	N/A	N/A	4.46%
Expected Life (Years)	N/A	N/A	7.0
Expected Volatility	N/A	N/A	17.73%
Expected Dividend Yield (Quarterly)	N/A	N/A	0.76%

The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the option. The expected life and expected volatility are based on historical experience.

For grants during the year ended September 30, 2007, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

Non-Performance Based Stock-settled SARs

Participants in the stock option and award plans did not exercise any non-performance based stock-settled SARs during the years ended September 30, 2009, 2008 and 2007 since none of the non-performance based stock-settled SARs granted have vested. As stated above, there were 50,000 non-performance based stock-settled SARs granted during 2007. The weighted average grant date fair value of non-performance based stock-settled SARs granted in 2007 is $7.81 per share. The Company did not grant any non-performance based stock-settled SARs during 2009 or 2008. As of September 30, 2009, unrecognized compensation expense related to non-performance based stock-settled SARs totaled approximately $0.1 million, which will be recognized over a weighted average period of 4.3 months. For a summary of transactions during 2009 involving non-performance based stock-settled SARs for all plans, refer to Note E — Capitalization and Short-Term Borrowings.

The fair value of non-performance based stock-settled SARs at the date of grant was estimated using the Black-Scholes-Merton closed form model. The following weighted average assumptions were used in estimating the fair value of options at the date of grant:

	Year Ended September 30		
	2009	2008	2007
Risk Free Interest Rate	N/A	N/A	4.53%
Expected Life (Years)	N/A	N/A	7.0
Expected Volatility	N/A	N/A	17.55%
Expected Dividend Yield (Quarterly)	N/A	N/A	0.73%

The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the non-performance based stock-settled SARs. The expected life and expected volatility are based on historical experience.

For grants during the year ended September 30, 2007, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

Performance Based Stock-settled SARs

Participants in the stock option and award plans did not exercise any performance based stock-settled SARs during the years ended September 30, 2009, 2008 and 2007. As stated above, there were 610,000 and 321,000 performance based stock-settled SARs granted during the years ended September 30, 2009 and 2008, respectively. The weighted average grant date fair value of performance based stock-settled SARs granted in 2009 and 2008 is $4.09 per share and $9.06 per share, respectively. The Company did not grant any performance based stock-settled SARs during 2007. For the year ended September 30, 2009, 96,984 performance based stock-settled SARs became fully vested. Fiscal 2009 was the first year in which performance based stock-settled SARs became vested. The total fair value of the performance based stock-settled SARs that became vested during the year ended September 30, 2009 was approximately $0.8 million. As of September 30, 2009, unrecognized compensation expense related to performance based stock-settled SARs totaled approximately $1.3 million, which will be recognized over a weighted average period of 10.9 months. For a summary of transactions during 2009 involving performance based stock-settled SARs for all plans, refer to Note E — Capitalization and Short-Term Borrowings.

The fair value of performance based stock-settled SARs at the date of grant was estimated using the Black-Scholes-Merton closed form model. The following weighted average assumptions were used in estimating the fair value of options at the date of grant:

	Year Ended September 30		
	2009	2008	2007
Risk Free Interest Rate	2.56%	3.78%	N/A
Expected Life (Years)	7.50	7.25	N/A
Expected Volatility	22.16%	17.69%	N/A
Expected Dividend Yield (Quarterly)	1.09%	0.64%	N/A

The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the performance based stock-settled SARs. The expected life and expected volatility are based on historical experience.

For grants during the years ended September 30, 2009 and 2008, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

Restricted Share Awards

The weighted average fair value of restricted share awards granted in 2009, 2008 and 2007 is $47.46 per share, $48.41 per share and $40.18 per share, respectively. As of September 30, 2009, unrecognized compensation expense related to restricted share awards totaled approximately $3.9 million, which will be recognized over a weighted average period of 4.4 years. For a summary of transactions during 2009 involving restricted share awards, refer to Note E — Capitalization and Short-Term Borrowings.

New Authoritative Accounting and Financial Reporting Guidance

In September 2006, the FASB issued authoritative guidance for using fair value to measure assets and liabilities. This guidance serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. This guidance is to be applied whenever assets or liabilities are to be measured at fair value. On October 1, 2008, the Company adopted this guidance for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis. This guidance delays the effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value on a recurring basis, until the Company's first quarter of fiscal 2010. For further discussion of the impact of the adoption of the authoritative guidance for financial assets and financial liabilities, refer to Note F — Fair Value Measurements. The Company is currently evaluating the impact that the adoption of the authoritative guidance for nonfinancial assets and nonfinancial liabilities will have on its consolidated financial statements. The Company has identified Goodwill as being the major nonfinancial asset that may be impacted by the adoption of this guidance. The Company does not believe there are any nonfinancial liabilities that will be impacted by the adoption of this guidance.

In September 2006, the FASB issued authoritative guidance which requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. This guidance requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. This guidance also specifies that a plan's assets and obligations that determine its funded status be measured as of the end of the Company's fiscal year, with limited exceptions. In accordance with this authoritative guidance, the Company has recognized the funded status of its benefit plans and implemented the related disclosure requirements at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company's fiscal year-end date was fully adopted by the Company as of September 30, 2009. The Company has historically measured its plan assets and benefit obligations using a June 30th measurement date. As a result of the change to a September 30th measurement date, the Company recorded fifteen months of pension and other post-retirement benefit costs during fiscal 2009. Such costs were calculated using June 30, 2008 measurement date data. Three of those months pertain to the period of July 1, 2008 to September 30, 2008. The pension and other post-retirement benefit costs for that period amounted to $5.1 million and were recorded by the Company during the quarter ended December 31, 2008 as a $3.8 million increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a $1.3 million ($0.8 million after tax) adjustment to earnings reinvested in the business. Refer to Note H — Retirement Plan and Other Post-Retirement Benefits for further disclosures regarding the impact of this authoritative guidance on the Company's consolidated financial statements.

In December 2007, the FASB revised authoritative guidance that significantly changes the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under this guidance, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. This guidance is effective as of the Company's first quarter of fiscal 2010.

In December 2007, the FASB issued authoritative guidance that changes the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. This authoritative guidance is effective as of the Company's first quarter of fiscal 2010. The Company currently does not have any NCI.

In March 2008, the FASB issued authoritative guidance that requires entities to provide enhanced disclosures related to an entity's derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity's financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under authoritative guidance for derivative instruments and hedging activities, and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. The Company adopted the disclosure provisions of this authoritative guidance during the Company's second quarter of fiscal 2009. Refer to Note G — Financial Instruments for these disclosures.

In June 2008, the FASB issued authoritative guidance concerning whether certain instruments granted in share-based payment transactions are participating securities. This guidance specified that unvested share-based payment awards that contain nonforfeitable rights to dividends are participating securities and shall be included in the computation of earnings per share pursuant to the "two-class" method. The "two-class" method allocates undistributed earnings between common shares and participating securities. This authoritative guidance is effective as of the Company's first quarter of fiscal 2010. The Company does not believe this guidance will have a material impact on its earnings per share calculation.

On December 31, 2008, the SEC issued a final rule on Modernization of Oil and Gas Reporting. The final rule modifies the SEC's reporting and disclosure rules for oil and gas reserves and aligns the full cost accounting rules with the revised disclosures. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements are effective for the Company's Form 10-K for the period ended September 30, 2010. Early adoption is not permitted. The Company is currently evaluating the impact that adoption of these rules will have on its consolidated financial statements and MD&A disclosures.

In March 2009, the FASB issued authoritative guidance that expands the disclosures required in an employer's financial statements about pension and other post-retirement benefit plan assets. The additional disclosures include more details on how investment allocation decisions are made, the plan's investment policies and strategies, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period, and disclosure regarding significant concentrations of risk within plan assets. The additional disclosure requirements are required for the Company's Form 10-K for the period ended September 30, 2010. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statement disclosures.

Effective with the June 30, 2009 Form 10-Q, the Company adopted the FASB authoritative guidance for subsequent events that establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Refer to Note R — Subsequent Events for disclosures made as a result of the adoption of this guidance.

In June 2009, the FASB issued authoritative guidance that establishes the FASB Accounting Standards Codification™ (the Codification) as the source of authoritative GAAP recognized by the FASB to be applied by all nongovernmental entities in the preparation of financial statements in conformity with GAAP. Rules and interpretive releases of the SEC under authority of federal securities law are also sources of authoritative GAAP for SEC registrants. All other nongrandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. The Codification was effective for interim and annual periods ending after September 15, 2009. Effective with this September 30, 2009 Form 10-K, the Company has updated its disclosures to conform to the Codification. There has been no impact on the Company's consolidated financial statements as the Codification does not change or alter existing GAAP.

Note B — Asset Retirement Obligations

The Company accounts for asset retirement obligations in accordance with the authoritative guidance that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. An asset retirement obligation is defined as a legal obligation associated with the retirement of a tangible long-lived asset in which the timing and/or method of settlement may or may not be conditional on a future event that may or may not be within the control of the Company. 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.

As previously disclosed, the Company follows the full cost method of accounting for its exploration and production costs. In accordance with the current authoritative guidance for asset retirement obligations, the Company has recorded an asset retirement obligation representing plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and has capitalized such costs in property, plant and equipment (i.e. the full cost pool). Under the current authoritative guidance for asset retirement obligations, since plugging and abandonment costs are already included in the full cost pool, the units-of-production depletion calculation excludes from the depletion base any estimate of future plugging and abandonment costs that are already recorded in the full cost pool.

The full cost method of accounting provides a limit to the amount of costs that can be capitalized in the full cost pool. This limit is referred to as the full cost ceiling. In accordance with current authoritative guidance, since the full cost pool includes an amount associated with plugging and abandoning the wells, as discussed in the preceding paragraph, the calculation of the full cost ceiling no longer reduces the future net cash flows from proved oil and gas reserves by an estimate of plugging and abandonment costs.

In addition to the asset retirement obligation recorded in the Exploration and Production segment, the Company has recorded future asset retirement obligations associated with the plugging and abandonment of natural gas storage wells in the Pipeline and Storage segment and the removal of asbestos and asbestos-containing material in various facilities in the Utility and Pipeline and Storage segments. The Company has also recorded asset retirement obligations for certain costs connected with the retirement of distribution mains and services pipeline systems in the Utility segment and with the transmission mains and other components in the pipeline systems in the Pipeline and Storage segment. These retirement costs within the distribution and transmission systems are primarily for the capping and purging of pipe, which are generally abandoned in place when retired, as well as for the clean-up of PCB contamination associated with the removal of certain pipe.

A reconciliation of the Company's asset retirement obligation is shown below:

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
Balance at Beginning of Year	$ 93,247	$75,939	$77,392
Liabilities Incurred and Revisions of Estimates	4,492	18,739	(932)
Liabilities Settled	(13,155)	(6,871)	(6,108)
Accretion Expense	6,789	5,440	5,394
Exchange Rate Impact	—	—	193
Balance at End of Year	$ 91,373	$93,247	$75,939

Note C — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30 2009	At September 30 2008
	(Thousands)	
Regulatory Assets(1):		
Pension and Other Post-Retirement Benefit Costs(2) (Note H)	$461,352	$147,909
Recoverable Future Taxes (Note D)	138,435	82,506
NYPSC Assessment(2)	24,445	—
Environmental Site Remediation Costs(2) (Note I)	21,456	22,530
Asset Retirement Obligations(2) (Note B)	7,884	8,155
Unamortized Debt Expense (Note A)	6,610	7,524
Unrecovered Purchased Gas Costs (See Regulatory Mechanisms in Note A)	—	37,708
Other(2)	15,776	10,993
Total Regulatory Assets	675,958	317,325
Regulatory Liabilities:		
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	105,778	2,753
Cost of Removal Regulatory Liability	105,546	103,100
Taxes Refundable to Customers (Note D)	67,046	18,449
Pension and Other Post-Retirement Benefit Costs(3) (Note H)	61,003	42,994
Tax Benefit on Medicare Part D Subsidy(3)	28,817	23,502
Off-System Sales and Capacity Release Credits(3)	8,340	8,977
Deferred Insurance Proceeds(3)	3,804	3,933
Other(3)	18,265	12,527
Total Regulatory Liabilities	398,599	216,235
Net Regulatory Position	$277,359	$101,090

(1) The Company recovers the cost of its regulatory assets but generally does not earn a return on them. There are a few exceptions to this rule. For example, the Company does earn a return on Unrecovered Purchased Gas Costs and, in the New York jurisdiction of its Utility segment, earns a return, within certain parameters, on the excess of cumulative funding to the pension plan over the cumulative amount collected in rates.

(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 Consolidated Balance Sheets 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.

Cost of Removal Regulatory Liability

In the Company's Utility and Pipeline and Storage segments, costs of removing assets (i.e. asset retirement costs) are collected from customers through depreciation expense. These amounts are not a legal retirement obligation as discussed in Note B — Asset Retirement Obligations. Rather, they are classified as a regulatory liability in recognition of the fact that the Company has collected dollars from the customer that will be used in the future to fund asset retirement costs.

Tax Benefit on Medicare Part D Subsidy

The Company has established a regulatory liability for the tax benefit it will receive under the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act). The Act provides 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 the Company's Utility and Pipeline and Storage segments, the customer funds the Company's post-retirement benefit plans. As such, any tax benefit received under the Act must be flowed-through to the customer. Refer to Note H — Retirement Plan and Other Post-Retirement Benefits for further discussion of the Act and its impact on the Company.

Deferred Insurance Proceeds

The Company, in its Pipeline and Storage segment, has deferred environmental insurance settlement proceeds amounting to $3.8 million and $3.9 million at September 30, 2009 and 2008, respectively. Such proceeds have been deferred as a regulatory liability to be applied against any future environmental claims that may be incurred. The proceeds have been classified as a regulatory liability in recognition of the fact that customers funded the premiums on the former insurance policies.

NYPSC Assessment

On April 7, 2009, the Governor of the State of New York signed into law an amendment to the Public Service Law increasing the allowed utility assessment from the current rate of one-third of one percent to one percent of a utility's in-state gross operating revenue, together with a temporary surcharge equal, as applied, to an additional one percent of the utility's gross operating revenue. The NYPSC, in a generic proceeding initiated for the purpose of implementing the amended law, has authorized the recovery, through rates, of the full cost of the increased assessment. The assessment is currently being applied to customer bills in the Utility segment's New York jurisdiction.

Off-System Sales and Capacity Release Credits

The Company, in its Utility segment, has entered into off-system sales and capacity release transactions. Most of the margins on such transactions are returned to the customer with only a small percentage being retained by the Company. The amount owed to the customer has been deferred as a regulatory liability.

Note D — Income Taxes

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

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
Current Income Taxes —			
Federal	$43,300	$ 75,079	$ 99,608
State	10,341	20,257	21,700
Foreign	—	90	22
Deferred Income Taxes —			
Federal	(4,940)	56,668	39,340
State	2,419	15,828	10,751
Foreign	—	—	2,756
	51,120	167,922	174,177
Deferred Investment Tax Credit	(697)	(697)	(697)
Total Income Taxes	$50,423	$167,225	$173,480
Presented as Follows:			
Other Income	$ (697)	$ (697)	$ (697)
Income Tax Expense — Continuing Operations	51,120	167,922	131,813
Discontinued Operations —			
Income From Operations	—	—	2,792
Gain on Disposal	—	—	39,572
Total Income Taxes	$50,423	$167,225	$173,480

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

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
U.S.	$151,160	$435,982	$496,074
Foreign	(29)	(29)	14,861
	$151,131	$435,953	$510,935

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		
	2009	2008	2007
		(Thousands)	
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$ 52,896	$152,584	$178,827
Increase (Reduction) in Taxes Resulting from:			
State Income Taxes	8,294	23,455	21,093
Foreign Tax Differential	10	69	(20,980)
Miscellaneous	(10,777)	(8,883)	(5,460)
Total Income Taxes	$ 50,423	$167,225	$173,480

The foreign tax differential amount shown above for 2007 includes tax effects relating to the gain on disposition of a foreign subsidiary.

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

	At September 30	
	2009	2008
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 733,581	$ 673,313
Pension and Other Post-Retirement Benefit Costs	164,120	43,340
Other	69,297	55,391
Total Deferred Tax Liabilities	966,998	772,044
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(202,627)	(55,309)
Other	(154,358)	(80,492)
Total Deferred Tax Assets	(356,985)	(135,801)
Total Net Deferred Income Taxes	$ 610,013	$ 636,243
Presented as Follows:		
Net Deferred Tax Liability/(Asset) — Current	$ (53,863)	$ 1,871
Net Deferred Tax Liability — Non-Current	663,876	634,372
Total Net Deferred Income Taxes	$ 610,013	$ 636,243

As of September 30, 2009, the Company recorded a deferred tax asset relating to a federal net operating loss carryover of $25.1 million. This carryover, which is available as a result of an acquisition, expires in varying amounts between 2023 and 2029. Although this loss carryover is subject to certain annual limitations, no valuation allowance was recorded because of management's determination that the amount will be fully utilized during the carryforward period.

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 $67.0 million and $18.4 million at September 30, 2009 and 2008, 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 $138.4 million and $82.5 million at September 30, 2009 and 2008, respectively.

During fiscal 2009, consent was received from the Internal Revenue Service (IRS) National Office approving the Company's application to change its tax method of accounting for certain capitalized costs relating to its utility property. Included in the regulatory liabilities and assets as of September 30, 2009 noted above are liabilities of $47.3 million and assets of $51.1 million associated with this tax accounting method change.

The Company adopted the FASB authoritative guidance for income tax uncertainties on October 1, 2007. As of the date of adoption, a cumulative effect adjustment was recorded that resulted in a decrease to retained earnings of $0.4 million. Upon adoption, the unrecognized tax benefits were $1.7 million.

A reconciliation of the change in unrecognized tax benefits for the year ended September 30, 2009 and 2008 is as follows:

	Year Ended September 30	
	2009	2008
	(Thousands)	
Balance at Beginning of Year	$ 1,700	$1,700
Additions for Tax Positions Related to Current Year	8,721	—
Additions for Tax Positions of Prior Years	—	—
Reductions for Tax Positions of Prior Years	—	—
Settlements with Taxing Authorities	(1,700)	—
Lapse of Statute of Limitations	—	—
Balance at End of Year	$ 8,721	$1,700

The balance of $8.7 million as of September 30, 2009 relates to tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Due to the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not materially affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The Company anticipates that the unrecognized tax benefits will not significantly change within the next twelve months.

The Company recognizes interest relating to income taxes in Other Interest Expense and penalties relating to income taxes in Other Income. The Company did not recognize any interest expense related to income taxes during fiscal 2009. The Company recognized interest expense related to income taxes of $0.5 million during fiscal 2008. The Company has not accrued any penalties during fiscal 2009 and 2008.

The Company files U.S. federal and various state income tax returns. The IRS is currently conducting an examination of the Company for fiscal 2009 in accordance with the Compliance Assurance Process ("CAP"). The CAP audit employs a real time review of the Company's books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. While the federal statute of limitations remains open for fiscal 2006 and later years, IRS examinations for fiscal 2008 and prior years have been completed and the Company believes such years are effectively settled.

The Company is also subject to various routine state income tax examinations. The Company's operating subsidiaries mainly operate in four states which have statutes of limitations that generally expire between three to four years from the date of filing of the income tax return.

Note E — Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock		Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
	Shares	Amount			
	(Thousands, except per share amounts)				
Balance at September 30, 2006	83,403	$83,403	$543,730	$ 786,013	$ 30,416
Net Income Available for Common Stock				337,455	
Dividends Declared on Common Stock ($1.22 Per Share)				(101,496)	
Other Comprehensive Loss, Net of Tax					(24,137)
Adjustment to Recognize the Funded Position of the Pension and Other Post-Retirement Benefit Plans					(12,482)
Share-Based Payment Expense(2)			3,727		
Common Stock Issued Under Stock and Benefit Plans(1)	1,367	1,367	30,193		
Share Repurchases	(1,309)	(1,309)	(8,565)	(38,196)	
Balance at September 30, 2007	83,461	83,461	569,085	983,776	(6,203)
Net Income Available for Common Stock				268,728	
Dividends Declared on Common Stock ($1.27 Per Share)				(103,523)	
Cumulative Effect of the Adoption of Authoritative Guidance for Income Taxes				(406)	
Other Comprehensive Income, Net of Tax					9,166
Share-Based Payment Expense(2)			2,332		
Common Stock Issued Under Stock and Benefit Plans(1)	854	854	33,335		
Share Repurchases	(5,194)	(5,194)	(37,036)	(194,776)	
Balance at September 30, 2008	79,121	79,121	567,716	953,799	2,963
Net Income Available for Common Stock				100,708	
Dividends Declared on Common Stock ($1.32 Per Share)				(105,410)	
Adoption of Authoritative Guidance for Defined Benefit Pension and Other Post-Retirement Plans				(804)	
Other Comprehensive Loss, Net of Tax					(45,359)
Share-Based Payment Expense(2)			2,055		
Common Stock Issued Under Stock and Benefit Plans(1)	1,379	1,379	33,068		
Balance at September 30, 2009	80,500	$80,500	$602,839	$ 948,293(3)	$(42,396)

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(1) Paid in Capital includes tax benefits of $5.9 million, $16.3 million and $13.7 million for September 30, 2009, 2008 and 2007, respectively, associated with the exercise of stock options.

(2) Paid in Capital includes compensation costs associated with stock option, stock-settled SARs and/or restricted stock awards. The expense is included within Net Income Available For Common Stock, net of tax benefits.

(3) 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, 2009, $804.1 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.

During 2009, the Company issued 1,609,597 original issue shares of common stock as a result of stock option exercises and 63,000 original issue shares for restricted stock awards (non-vested stock as defined in existing guidance). Holders of stock options or restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During 2009, 303,091 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

The Company also has a director stock program under which it issues shares of Company common stock to the eight non-employee directors of the Company who receive compensation under the Company's Retainer Policy for Non-Employee Directors, as partial consideration for the directors' services. Under this program, the Company issued 9,865 original issue shares of common stock during 2009.

In December 2005, the Company's Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may repurchase outstanding shares of common stock, up to an aggregate amount of eight million shares in the open market or through privately negotiated transactions. The Company completed the repurchase of the eight million shares during 2008 for a total program cost of $324.2 million (of which 4,165,122 shares were repurchased during the year ended September 30, 2008 for $191.0 million). In September 2008, the Company's Board of Directors authorized the repurchase of an additional eight million shares. Under this new authorization, the Company repurchased 1,028,981 shares for $46.0 million through September 17, 2008. The Company, however, stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. Such repurchases may be made in the future. The share repurchases mentioned above were funded with cash provided by operating activities and/or through the use of the Company's lines of credit.

Shareholder Rights Plan

In 1996, the Company's Board of Directors adopted a shareholder rights plan (Plan). The Plan has been amended several times since it was adopted and is now embodied in an Amended and Restated Rights

Agreement effective December 4, 2008, a copy of which was included as an exhibit to the Form 8-K filed by the Company on December 4, 2008.

Pursuant to the Plan, the holders of the Company's common stock have one right (Right) for each of their shares. Each Right is initially evidenced by the Company's common stock certificates representing the outstanding shares of common stock.

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

The Rights become exercisable upon the occurrence of a Distribution Date as described below, but after a Distribution Date Rights that are owned by an Acquiring Person will be null and void. At any time following a Distribution Date, each holder of a Right may exercise its right to receive, upon payment of an amount calculated under the Rights Agreement, common stock of the Company (or, under certain circumstances, other securities or assets of the Company) having a value equal to two times the amount paid to exercise the Right. 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 (including Synthetic Long Positions as defined in the Plan) 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, upon exercise of the right, common stock of the acquiring company having a value equal to two times the amount paid to exercise the right. 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 Distribution Date, 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 Distribution Date, 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.

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, 2018, unless earlier than that date, they are exchanged or redeemed or the Plan is amended to extend the expiration date.

Stock Option and Stock Award Plans

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, stock-settled SARs, restricted stock, performance units or performance shares. Stock options and stock-settled SARs 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 or stock-settled SAR 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	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2008	6,464,697	$26.17		
Granted in 2009	—	$ —		
Exercised in 2009	(1,609,597)	$23.15		
Forfeited in 2009	—	$ —		
Outstanding at September 30, 2009	4,855,100	$27.18	2.80	$90,463
Option shares exercisable at September 30, 2009	4,755,100	$26.92	2.71	$89,832
Option shares available for future grant at September 30, 2009(1)	72,797			

(1) Including shares available for stock-settled SARs and restricted stock grants.

Transactions involving non-performance based stock-settled SARs for all plans are summarized as follows:

	Number of Shares Subject To Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2008	50,000	$41.20		
Granted in 2009	—	$ —		
Exercised in 2009	—	$ —		
Forfeited in 2009	—	$ —		
Outstanding at September 30, 2009	50,000	$41.20	7.45	$231
Stock-settled SARs exercisable at September 30, 2009	—	—	—	$ —

Transactions involving performance based stock-settled SARs for all plans are summarized as follows:

	Number of Shares Subject To Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2008	315,000	$48.26		
Granted in 2009	610,000	$29.88		
Exercised in 2009	—	$ —		
Forfeited in 2009	—	$ —		
Outstanding at September 30, 2009	925,000	$36.14	8.96	$8,947
Stock-settled SARs exercisable at September 30, 2009	96,984	$47.37	8.40	$ —

Restricted Share Awards

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 vesting period. 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.

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

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Restricted Share Awards Outstanding at September 30, 2008	58,828	$42.65
Granted in 2009	63,000	$47.46
Vested in 2009	(3,828)	$31.30
Forfeited in 2009	—	$ —
Restricted Share Awards Outstanding at September 30, 2009	118,000	$46.59

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2009 will lapse as follows: 2010 — 27,500 shares; 2011 — 2,500 shares; 2012 — 5,000 shares; 2013 — 5,000 shares; 2014 — 5,000 shares; 2015 — 13,000 shares; 2016 — 5,000 shares; 2018 — 35,000 shares; and 2021 — 20,000 shares.

Redeemable Preferred Stock

As of September 30, 2009, 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 2009	At September 30 2008
	(Thousands)	
Medium-Term Notes(1):		
6.7% to 7.50% due November 2010 to June 2025	$ 449,000	$ 549,000
Notes(1):		
5.25% to 8.75% due March 2013 to May 2019	800,000	550,000
Total Long-Term Debt	1,249,000	1,099,000
Less Current Portion	—	100,000
	$1,249,000	$ 999,000

(1) The Medium-Term Notes and Notes are unsecured.

In April 2009, the Company issued $250.0 million of 8.75% notes due in May 2019. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $247.8 million. These notes were registered under the Securities Act of 1933. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including to replenish cash that was used to pay the $100 million due at the maturity of the Company's 6.0% medium-term notes on March 1, 2009.

In April 2008, the Company issued $300.0 million of 6.50% senior, unsecured notes in a private placement exempt from registration under the Securities Act of 1933. In February 2009, the Company exchanged the notes for economically identical notes registered under the Securities Act of 1933. The notes have a term of 10 years, with a maturity date in April 2018. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. The Company used $200.0 million of the proceeds of the issuance to refund $200.0 million of 6.303% medium-term notes that matured on May 27, 2008.

As of September 30, 2009, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: zero in 2010, $200.0 million in 2011, $150.0 million in 2012, $250.0 million in 2013, zero in 2014, and $649.0 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 uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $420.0 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, or replaced by similar lines. The total amount available to be issued under the Company's commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million that extends through September 30, 2010.

At September 30, 2009 and 2008, the Company had no outstanding short-term notes payable to banks or commercial paper.

Debt Restrictions

Under the Company's committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through September 30, 2010. At September 30, 2009, the Company's debt to capitalization ratio (as calculated under the facility) was .44. The constraints specified in the committed credit facility would permit an additional $1.7 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio would exceed .65. 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 credit facility, 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, 2009, the Company would have been permitted to issue up to a maximum of $435.0 million in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. If the Company were to experience another impairment of oil and gas properties in the future, it is possible that these indenture covenants would restrict the Company's ability to issue additional long-term unsecured indebtedness. This would not preclude the Company from issuing new indebtedness to replace maturing debt.

The Company's 1974 indenture pursuant to which $99.0 million (or 7.9%) of the Company's long-term debt (as of September 30, 2009) 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 $300.0 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 fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more, or (ii) an event occurs that causes, or would permit the holders of 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, 2009, the Company had no debt outstanding under the committed credit facility.

Note F — Fair Value Measurements

Beginning in fiscal 2009, the Company adopted the FASB authoritative guidance regarding fair value measurements which establishes a fair-value hierarchy and prioritizes the inputs used in valuation techniques that measure fair value. Those inputs are prioritized into three levels. Level 1 inputs are unadjusted quoted prices in active markets for assets or liabilities that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly at the measurement date. Level 3 inputs are unobservable inputs for the asset or liability at the measurement date. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The adoption of this authoritative guidance regarding fair value measurements has not had a significant impact on the consolidated financial statements.

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Recurring Fair Value Measures	At fair Value as of September 30, 2009			
	Level 1	Level 2	Level 3	Total
		(Dollars in thousands)		
Assets:				
Cash Equivalents	$390,462	$ —	$ —	$390,462
Derivative Financial Instruments	5,312	12,536	26,969	44,817
Other Investments	24,276	—	—	24,276
Hedging Collateral Deposits	848	—	—	848
Total	$420,898	$12,536	$26,969	$460,403
Liabilities:				
Derivative Financial Instruments	$ —	$ 2,148	$ —	$ 2,148
Total	$ —	$ 2,148	$ —	$ 2,148

Cash Equivalents

The cash equivalents reported in Level 1 consist of SEC registered money market mutual funds.

Derivative Financial Instruments

The derivative financial instruments reported in Level 1 consist of NYMEX futures contracts. The hedging collateral deposits associated with these futures contracts have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 consist of natural gas swap agreements used in the Company's Exploration and Production segment and natural gas swap agreements used in the Energy Marketing segment. The fair value of these natural gas swap agreements is based on an internal model that uses observable inputs. The fair market value of the price swap agreements reported in Level 2 as assets has been reduced by $0.2 million based on an assessment of counterparty credit risk. The derivative financial instruments reported in Level 3 consist of all of the Exploration and Production segment's crude oil swap agreements. The fair value of the crude oil swap agreements is based on an internal model that uses both observable and unobservable inputs. The fair market value of the price swap agreements reported in Level 3 as assets has been reduced by $0.7 million based on an assessment of counterparty credit risk. The fair market value of the price swap agreements reported in Level 2 as liabilities has been reduced by less than $0.1 million based on an assessment of the Company's credit risk. This credit reserve, as well as the credit reserve established for the Level 2 and Level 3 swap agreement assets, was determined by applying default probabilities to the anticipated cash flows that the Company is either expecting from its counterparties or expecting to pay to its counterparties.

Other Investments

The other investments reported in Level 1 consist of publicly traded equity securities and a publicly traded balanced equity mutual fund.

The table listed below provides a reconciliation of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3.

Fair Value Measurements Using Unobservable Inputs (Level 3)

	October 1, 2008	Total Gains/Losses— Realized and Unrealized: Included in Earnings	Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2009
			(Dollars in thousands)		
Assets:					
Derivative Financial Instruments	$7,110	$(47,076)(1)	$75,077	$(8,142)(2)	$26,969
Total	$7,110	$(47,076)	$75,077	$(8,142)	$26,969
Liabilities:					
Derivative Financial Instruments	$ (777)	$(12,104)(1)	$12,070	$ 811(2)	$ —
Total	$ (777)	$(12,104)	$12,070	$ 811	$ —

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2009.

(2) These transfers occurred because the Company was able to obtain and utilize forward-looking, observable basis differential information for its hedges on southern California natural gas production.

Note G — Financial Instruments

Long-Term Debt

At September 30, 2009, the fair market value of the Company's debt, as presented in the table below, was determined using a discounted cash flow model, which incorporates the Company's credit risk in determining the yield, and subsequently, the fair market value of the debt. At September 30, 2008, the fair market value of the Company's long-term debt was determined 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: 2009 Carrying Amount	2009 Fair Value	2008 Carrying Amount	2008 Fair Value
		(Thousands)		
Long-Term Debt	$1,249,000	$1,347,368	$1,099,000	$1,027,098

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay. Carrying amounts for other financial instruments recorded on the Company's Consolidated Balance Sheets approximate fair value.

Other Investments

Investments in life insurance are stated at their cash surrender values or net present value 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 include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity securities. The values of the insurance contracts amounted to $54.2 million and $53.6 million at September 30, 2009 and 2008, respectively. The fair value of the equity mutual fund was $15.8 million and $12.4 million at September 30, 2009 and 2008, respectively. The gross unrealized loss on this equity mutual fund was $1.0 million at September 30, 2009 and September 30, 2008. Although this investment has been in an unrealized loss position for over twelve months, management has the intent and ability to hold the investment for a sufficient period of time for the asset to recover in value. As such, management does not consider this investment to be other than temporarily impaired. The fair value of the stock of an insurance company was $8.3 million and $14.5 million at September 30, 2009 and 2008, respectively. The gross unrealized gain on this stock was $5.9 million and $12.1 million at September 30, 2009 and 2008, 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 is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is commodity price risk in the Exploration and Production and Energy Marketing segments. The Company enters into futures contracts and over-the-counter swap agreements for natural gas and crude oil to manage the price risk associated with forecasted sales of gas and oil. The Company also enters into futures contracts and swaps to manage the risk associated with forecasted gas purchases, storage of gas, and withdrawal of gas from storage to meet customer demand. The duration of the Company's hedges do not typically exceed 3 years and the majority of the positions settle within one year.

The Company has presented its net derivative assets and liabilities on its Consolidated Balance Sheet at September 30, 2009 as shown in the table below.

Fair Values of Derivative Instruments (Dollar Amounts in Thousands)

Derivatives Designated as Hedging Instruments	Asset Derivatives September 30, 2009		Liability Derivatives September 30, 2009	
	Consolidated Balance Sheet Location	Fair Value	Consolidated Balance Sheet Location	Fair Value
Commodity Contracts	Fair Value of Derivative Financial Instruments	$44,817	Fair Value of Derivative Financial Instruments	$2,148

The following table discloses the fair value of derivative contracts on a gross-contract basis as opposed to the net-contract basis presentation on the Consolidated Balance Sheet at September 30, 2009.

Fair Values of Derivative Instruments (Dollar Amounts in Thousands)

Derivatives Designated as Hedging Instruments	Gross Asset Derivatives September 30, 2009	Gross Liability Derivatives September 30, 2009
	Fair Value	Fair Value
Commodity Contracts	$63,601	$20,932

Cash Flow Hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

As of September 30, 2009, the Company's Exploration and Production segment had the following commodity derivative contracts (swaps) outstanding to hedge forecasted sales (where the Company uses short positions (i.e. positions that pay-off in the event of commodity price decline) to mitigate the risk of decreasing revenues and earnings):

Commodity	Units
Natural Gas	36.9 Bcf (all short positions)
Crude Oil	2,688,000 Bbls (all short positions)

As of September 30, 2009, the Company's Energy Marketing segment had the following commodity derivative contracts (futures contracts and swaps) outstanding to hedge forecasted sales (where the Company uses short positions to mitigate the risk associated with natural gas price decreases and its impact on decreasing revenues and earnings) and purchases (where the Company uses long positions (i.e. positions that pay-off in the event of commodity price increases) to mitigate the risk of increasing natural gas prices, which would lead to increased purchased gas expense and decreased earnings):

Commodity	Units
Natural Gas	6.4 Bcf (6.2 Bcf short positions (forecasted storage withdrawals) and 0.2 Bcf long positions (forecasted storage injections))

As of September 30, 2009, the Company's Exploration and Production segment had $36.2 million ($21.3 million after tax) of gains included in the accumulated other comprehensive income balance. It is expected that $36.4 million ($21.4 million after tax) of these gains will be reclassified into income within the next 12 months as the sales of the underlying commodities are expected to occur. See Note A, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain on Derivative Financial Instruments in Note A includes both the Exploration and Production and Energy Marketing segments).

As of September 30, 2009, the Company's Energy Marketing segment had $4.7 million ($2.8 million after tax) of losses included in the accumulated other comprehensive income (loss) balance. It is expected that $4.7 million ($2.8 million after tax) of these losses will be reclassified into income within the next 12 months as the sales and purchases of the underlying commodities occur. See Note A, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain on Derivative Financial Instruments in Note A includes both the Exploration and Production and Energy Marketing segments).

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Year Ended September 30, 2009 (Dollar Amounts in Thousands)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Effective Portion) for the Year Ended September 30, 2009	Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Year Ended September 30, 2009	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Year Ended September 30, 2009
Commodity Contracts — Exploration & Production segment	$110,883	Operating Revenue	$ 91,808	Operating Revenue	$ —
Commodity Contracts — Energy Marketing segment	$ 7,492	Purchased Gas	$ 21,301	Operating Revenue	$ —
Commodity Contracts — Pipeline & Storage segment(1)	$ 652	Operating Revenue	$ 1,952	Operating Revenue	$ —
Commodity Contracts — All Other(1)	$ 183	Purchased Gas	$ (681)	Purchased Gas	$ —
Total	$119,210		$114,380		$ —

(1) There were no open hedging positions at September 30, 2009. As such there is no mention of these positions in the preceding sections of this footnote.

Fair value hedges

The Company's Energy Marketing segment utilizes fair value hedges to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and commitments related to the injection and withdrawal of storage gas. In order to hedge fixed price sales commitments, the Company enters into long positions to mitigate the risk that after the Company enters into fixed price sales agreements with its customers, the price of natural gas increases (thereby passing up the opportunity for higher operating revenue). With fixed price purchase commitments, the Company enters into short positions to mitigate the risk that after the Company locks into fixed price purchase deals with its suppliers, the price of natural gas decreases (thereby passing up the opportunity for lower purchased gas expense). Fair value hedges related to the injection and withdrawal of storage gas impact purchased gas expense. As of September 30, 2009, the Company's Energy Marketing segment had fair value hedges covering approximately 13.0 Bcf (11.7 Bcf of fixed price sales commitments (all long positions), 0.9 Bcf of fixed price purchase commitments (all short positions), and 0.4 Bcf of commitments related to the withdrawal of storage gas (all short positions)). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Consolidated Statement of Income	Gain/(Loss) on Derivative	Gain/(Loss) on Commitment
Operating Revenues	$ 5,242,000	$(5,242,000)
Purchased Gas	$(8,252,000)	$ 8,252,000

Derivatives in Fair Value Hedging Relationships	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income	Amount of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income for the Year Ended September 30, 2009
		(In thousands)
Commodity Contracts — Energy Marketing segment(1)	Operating Revenues	$ 5,242
Commodity Contracts — Energy Marketing segment(2)	Purchased Gas	$ 11
Commodity Contracts — Energy Marketing segment(3)	Purchased Gas	$ (8,263)
		$(3,010)

(1) Represents hedging of fixed price sales commitments of natural gas.

(2) Represents hedging of fixed price purchase commitments of natural gas.

(3) Represents hedging of storage withdrawal commitments of natural gas.

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. 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 a quarterly basis monitors counterparty credit exposure. The majority of the Company's counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with ten counterparties. At September 30, 2009, the Company had derivative financial instruments that were in gain positions with eight of the counterparties. The Company had derivative financial instruments that were in loss positions with the other two counterparties. The Company had $26.6 million of credit exposure with one counterparty (which is rated A1 (Moody's Investor Service), A (S&P), and A+ (Fitch Ratings Service) as of September 30, 2009). On average for those financial instruments that were in a gain position, the Company had $1.8 million of credit exposure per counterparty with the other seven counterparties that were in a gain position. The Company had not received any collateral from the counterparties at September 30, 2009 since the Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral.

As of September 30, 2009, eight of the ten counterparties to the Company's outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk-related contingency feature. In the event the Company's credit rating increases or falls below a certain threshold (the lower of the S&P or Moody's Debt Rating), the available credit extended to the Company would either increase or decrease. A decline in the Company's credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company's outstanding derivative instrument contracts were in a liability position and the Company's credit rating declined, then additional hedging collateral deposits would be required. At September 30, 2009, these credit-risk related contingency features were not triggered since the Company had assets of $37.9 million related to derivative financial instruments with the eight counterparties.

For its exchange traded futures contracts, which are in an asset position, the Company had paid $0.8 million in hedging collateral as of September 30, 2009. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions (i.e. those positions that have been settled for cash) and margin requirements. (This is discussed in Note A under Hedging Collateral Deposits.)

Note H — Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan) that covers a majority of the full-time employees of the Company. The Retirement Plan covers certain non-collectively bargained employees hired before July 1, 2003 and certain collectively bargained employees hired before November 1, 2003. Employees hired after June 30, 2003 are eligible for a Retirement Savings Account benefit provided under the Company's defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account were $0.4 million, $0.2 million and $0.2 million for the years ended September 30, 2009, 2008 and 2007, respectively. Costs associated with the Company's contributions to the Tax-Deferred Savings Plans were $4.1 million, $4.0 million, and $4.1 million for the years ended September 30, 2009, 2008 and 2007, respectively.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The other post-retirement benefits cover certain non-collectively bargained employees hired before January 1, 2003 and certain collectively bargained employees hired before October 31, 2003.

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 VEBA trusts for its other post-retirement benefits. 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' other post-retirement benefits, as well as benefits as they are paid to current retirees. In addition, the Company has established 401(h) accounts for its other post-retirement benefits. They are separate accounts within the Retirement Plan trust used to pay retiree medical benefits for the associated participants in the Retirement Plan. Although these accounts are in the Retirement Plan trust, for funding status purposes as shown below, the 401(h) accounts are included in Fair Value of Assets under Other Post-Retirement Benefits. Contributions are tax-deductible when made, subject to limitations contained in the Internal Revenue Code and regulations. Retirement Plan, VEBA trust and 401(h) account assets primarily consist of equity and fixed income investments or units in commingled funds or money market funds.

The expected return on plan assets, a component of net periodic benefit cost shown in the tables below, is applied to the market-related value of plan assets. The market-related value of plan assets is equal to market value as of the measurement date.

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 other post-retirement benefits are shown in the tables below. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is September 30, 2009, June 30, 2008 and June 30, 2007, for fiscal year 2009, 2008 and 2007, respectively.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2009	2008	2007	2009	2008	2007
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 719,059	$742,519	$732,207	$ 411,545	$444,545	$445,931
Service Cost	10,913	12,597	12,898	3,801	5,104	5,614
Interest Cost	46,836	44,949	44,350	27,499	27,081	27,198
Plan Participants' Contributions	—	—	—	2,185	1,990	1,566
Retiree Drug Subsidy Receipts	—	—	—	1,427	1,532	1,325
Amendments(1)	—	—	—	(10,765)	(31,874)	—
Actuarial (Gain) Loss	102,430	(34,189)	(2,986)	55,776	(14,390)	(14,450)
Adjustment for Change in Measurement Date	14,438	—	—	7,825	—	—
Benefits Paid	(62,180)	(46,817)	(43,950)	(31,998)	(22,443)	(22,639)
Benefit Obligation at End of Period	$ 831,496	$719,059	$742,519	$ 467,295	$411,545	$444,545
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 695,089	$765,144	$664,521	$ 377,640	$412,371	$325,624
Actual Return on Plan Assets	(99,511)	(39,206)	119,662	(62,368)	(43,478)	65,552
Employer Contributions	15,993	3,817	16,488	25,659	29,200	42,268
Employer Contributions During Period from Measurement Date to Fiscal Year End	N/A	12,151	8,423	N/A	—	—
Plan Participants' Contributions	—	—	—	2,185	1,990	1,566
Adjustment for Change in Measurement Date	14,490	—	—	7,904	—	—
Benefits Paid	(62,180)	(46,817)	(43,950)	(31,998)	(22,443)	(22,639)
Fair Value of Assets at End of Period	$ 563,881	$695,089	$765,144	$ 319,022	$377,640	$412,371
Net Amount Recognized at End of Period (Funded Status)	$(267,615)	$ (23,970)	$ 22,625	$(148,273)	$ (33,905)	$ (32,174)
Amounts Recognized in the Balance Sheets Consist of:						
Accrued Benefit Liability	$(267,615)	$ (23,970)	$ —	$(148,273)	$ (54,939)	$ (70,555)
Prepaid Benefit Cost	—	—	22,625	—	21,034	38,381
Net Amount Recognized at End of Period	$(267,615)	$ (23,970)	$ 22,625	$(148,273)	$ (33,905)	$ (32,174)
Accumulated Benefit Obligation	$ 758,658	$659,004	$672,340	N/A	N/A	N/A

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2009	2008	2007	2009	2008	2007
	(Thousands)					
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	5.50%	6.75%	6.25%	5.50%	6.75%	6.25%
Expected Return on Plan Assets	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Rate of Compensation Increase	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Components of Net Periodic Benefit Cost						
Service Cost	$ 10,913	$ 12,597	$ 12,898	$ 3,801	$ 5,104	$ 5,614
Interest Cost	46,836	44,949	44,350	27,499	27,081	27,198
Expected Return on Plan Assets	(57,958)	(55,000)	(51,235)	(31,615)	(33,715)	(26,960)
Amortization of Prior Service Cost	732	808	882	(1,074)	4	4
Amortization of Transition Amount	—	—	—	2,265	7,127	7,127
Recognition of Actuarial Loss(2)	5,676	11,064	13,528	9,271	2,927	8,214
Net Amortization and Deferral for Regulatory Purposes	12,817	6,008	1,211	18,037	22,264	16,220
Net Periodic Benefit Cost	$ 19,016	$ 20,426	$ 21,634	$ 28,184	$ 30,792	$ 37,417
Accumulated Other Comprehensive Loss (Pre-Tax) Attributable to Recognition of Funded Status of Benefit Plans	N/A	N/A	$ 11,256	N/A	N/A	$ 778
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Discount Rate	6.75%	6.25%	6.25%	6.75%	6.25%	6.25%
Expected Return on Plan Assets	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Rate of Compensation Increase	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%

(1) In fiscal 2008 and 2009, the Company passed amendments, for most of the subsidiaries, which increased the participant contributions for active employees at the time of the amendment. This decreased the benefit obligation.

(2) Distribution Corporation's New York jurisdiction calculates the amortization of the actuarial loss on a vintage year basis over 10 years, as mandated by the NYPSC. All the other subsidiaries of the Company utilize the corridor approach.

The Net Periodic Benefit Cost in the table above includes the effects of regulation. The Company recovers pension and other post-retirement benefit costs in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorizations. Certain of those commission authorizations established tracking mechanisms which allow the Company to record the difference between the amount of pension and other post-retirement benefit costs recoverable in rates and the amounts of such costs as determined under the existing authoritative guidance as either a regulatory asset or liability, as appropriate. Any activity under the tracking mechanisms (including the amortization of pension and other post-retirement regulatory assets and liabilities) is reflected in the Net Amortization and Deferral for Regulatory Purposes line item above.

As note above, through 2008, the Company used June 30th as the measurement date for financial reporting purposes. In 2009, in accordance with the current authoritative guidance for defined benefit pension and other postretirement plans, the Company began measuring the Plan's assets and liabilities for its pension and other post-retirement benefit plans as of September 30th, its fiscal year end. In making this change and as permitted by the current authoritative guidance, the Company recorded fifteen months of pension and post-retirement benefits expense (for the period from July 1, 2008 through September 30, 2009) during the fiscal year ended September 30, 2009. The pension and other post-retirement benefit costs for the period of July 1, 2008 to September 30, 2008 amounted to \$3.8 million and were recorded by the Company during the year ended September 30, 2009 as a \$3.4 million increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a \$0.4 million (\$0.2 million after tax) adjustment to earnings reinvested in the business. In addition, for the Company's non-qualified benefit plan, benefit costs of \$1.3 million were recorded by the Company during the year ended September 30, 2009 as a \$0.4 million increase to Other Regulatory Assets in the Company's Utility segment and a \$0.9 million (\$0.6 million after tax) adjustment to earnings reinvested in the business.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2009, the changes in such amounts during 2009, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2010 are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits	Non-Qualified Benefit Plan
		(Thousands)	
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Loss	\$(324,615)	\$(191,360)	\$(24,690)
Transition Obligation	—	(2,027)	—
Prior Service (Cost) Credit	(4,581)	10,517	—
Net Amount Recognized	\$(329,196)	\$(182,870)	\$(24,690)
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2009(1)			
Increase in Net Actuarial Loss	\$(252,978)	\$(138,252)	\$(11,160)
Reduction in Transition Obligation	—	9,299	—
Prior Service (Cost) Credit	914	2,956	11
Net Change	\$(252,064)	\$(125,997)	\$(11,149)
Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)			
Net Actuarial Loss	\$ (21,641)	\$ (25,882)	\$ (2,623)
Transition Obligation	—	(541)	—
Prior Service (Cost) Credit	(655)	1,710	—
Net Amount Expected to be Recognized	\$ (22,296)	\$ (24,713)	\$ (2,623)

(1) Amounts presented are shown before recognizing deferred taxes.

In order to adjust the funded status of its pension and other post-retirement benefit plans at September 30, 2009, the Company recorded a \$318.4 million increase to Other Regulatory Assets in the Company's Utility and

Pipeline and Storage segments and a $70.8 million (pre-tax) increase to Accumulated Other Comprehensive Loss.

The effect of the discount rate change for the Retirement Plan in 2009 was to increase the projected benefit obligation of the Retirement Plan by $102.6 million. The effect of the discount rate change for the Retirement Plan in 2008 was to decrease the projected benefit obligation of the Retirement Plan by $38.6 million. In 2007, there was no change to the discount rate used to estimate the projected benefit obligation for the Retirement Plan.

The Company made cash contributions totaling $16.0 million to the Retirement Plan during the year ended September 30, 2009. The Company expects that the annual contribution to the Retirement Plan in 2010 will be in the range of $20.0 million to $30.0 million. It is likely that the Company will have to fund larger amounts to the Retirement Plan subsequent to 2010 in order to be in compliance with the Pension Protection Act of 2006.

The following benefit payments, which reflect expected future service, are expected to be paid during the next five years and the five years thereafter: $51.8 million in 2010; $52.2 million in 2011; $52.6 million in 2012; $53.3 million in 2013; $54.4 million in 2014; and $294.3 million in the five years thereafter.

In addition to the Retirement Plan discussed above, the Company also has a Non-Qualified benefit plan that covers a group of management employees designated by the Chief Executive Officer of the Company. This plan provides for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit cost associated with this plan was $5.2 million, $5.0 million and $5.5 million in 2009, 2008 and 2007, respectively. At September 30, 2007, an $8.0 million (pre-tax) loss was recognized in accumulated other comprehensive income (loss) on the Consolidated Balance Sheet upon adoption of the FASB revised authoritative guidance for defined benefit pension and other postretirement plans. The accumulated benefit obligation for this plan was $35.8 million and $31.8 million at September 30, 2009 and 2008, respectively. The projected benefit obligation for the plan was $60.3 million and $47.5 million at September 30, 2009 and 2008, respectively. The actuarial valuations for this plan were determined based on a discount rate of 5.25%, 6.75% and 6.25% as of September 30, 2009, 2008 and 2007, respectively; a rate of compensation increase of 10.0% as of September 30, 2009, 2008 and 2007; and an expected long-term rate of return on plan assets of 8.25% at September 30, 2009, 2008 and 2007.

The effect of the discount rate change in 2009 was to increase the other post-retirement benefit obligation by $60.9 million. Effective October 1, 2009, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to increase the other post-retirement benefit obligation by $27.0 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2009 by $32.1 million.

The effect of the discount rate change in 2008 was to decrease the other post-retirement benefit obligation by $26.3 million. Effective July 1, 2008, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to increase the other post-retirement benefit obligation by $20.0 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2008 by $8.1 million.

There was no change to the discount rate used to estimate the other post-retirement benefit obligation during 2007. Effective July 1, 2007, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to increase the other post-retirement benefit obligation by $8.6 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2007 by $23.0 million.

On December 8, 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. This Act introduced 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. 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 estimated gross other post-retirement benefit payments and gross amount of Medicare Part D prescription drug subsidy receipts are as follows:

	Benefit Payments	Subsidy Receipts
2010	$ 26,827,000	$ (1,933,000)
2011	$ 28,592,000	$ (2,156,000)
2012	$ 29,970,000	$ (2,444,000)
2013	$ 31,299,000	$ (2,758,000)
2014	$ 32,743,000	$ (3,066,000)
2015 through 2019	$185,348,000	$(20,026,000)

	2009	2008	2007
Rate of Increase for Pre Age 65 Participants	8.0%(1)	9.0%(2)	8.0%(3)
Rate of Increase for Post Age 65 Participants	7.0%(1)	7.0%(2)	6.67%(3)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	9.0%(1)	10.0%(2)	10.0%(3)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	7.0%(1)	7.0%(2)	7.0%(4)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy	7.9%(1)	10.0%(2)	10.0%(3)

(1) It was assumed that this rate would gradually decline to 4.5% by 2028.

(2) It was assumed that this rate would gradually decline to 5.0% by 2018.

(3) It was assumed that this rate would gradually decline to 5.0% by 2014.

(4) It was assumed that this rate would gradually decline to 5.0% by 2016.

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 other post-retirement benefit obligation as of October 1, 2009 would increase by $54.5 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 2009 by $3.9 million. If the health care cost trend rates were decreased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2009 would decrease by $46.2 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 2009 by $3.3 million.

The Company made cash contributions totaling $25.5 million to the VEBA trusts and 401(h) accounts during the year ended September 30, 2009. In addition, the Company made direct payments of $0.2 million to retirees not covered by the VEBA trusts and 401(h) accounts during the year ended September 30, 2009. The Company expects that the annual contribution to the VEBA trusts and 401(h) accounts in 2010 will be in the range of $25.0 million to $30.0 million.

The Company's Retirement Plan weighted average asset allocations (excluding the 401(h) accounts) at September 30, 2009, 2008 and 2007 by asset category are as follows:

Asset Category	Target Allocation 2010	Percentage of Plan Assets at September 30 2009	2008	2007
Equity Securities	60-75%	66%	67%	70%
Fixed Income Securities	20-35%	21%	23%	18%
Other	0-15%	13%	10%	12%
Total		100%	100%	100%

The Company's weighted average asset allocations for its VEBA trusts and 401(h) accounts at September 30, 2009, 2008 and 2007 by asset category are as follows:

Asset Category	Target Allocation 2010	Percentage of Plan Assets at September 30 2009	2008	2007
Equity Securities	85-100%	93%	93%	95%
Fixed Income Securities	0-15%	2%	1%	1%
Other	0-15%	5%	6%	4%
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 Retirement Plan trust, the VEBA trusts and the 401(h) accounts 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.

The discount rate which is used to present value the future benefit payment obligations of the Retirement Plan and the Company's other post-retirement benefits is 5.50% as of September 30, 2009. The discount rate which is used to present value the future benefit payment obligations of the Non-Qualified benefit plan is 5.25% as of September 30, 2009. The Company utilizes a yield curve model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments.

Note I — Commitments and Contingencies

Environmental Matters

The Company is subject to various federal, state and local laws and regulations 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. At September 30, 2009, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $18.7 million to $22.9 million. The minimum estimated liability of $18.7 million has been recorded on the Consolidated Balance Sheet at September 30, 2009. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet (refer to Note C — Regulatory Matters for further discussion of the insurance proceeds). Other than as discussed below, the Company is currently not aware of any material exposure to environmental liabilities. However, changes in environmental regulations, new information or other factors could adversely impact the Company.

(i) Former Manufactured Gas Plant Sites

The Company has incurred investigation and/or clean-up costs at several former manufactured gas plant sites in New York and Pennsylvania. The Company continues to be responsible for future ongoing monitoring and long-term maintenance at two sites.

The Company has agreed with the NYDEC to remediate another former manufactured gas plant site located in New York. The Company has received approval from the NYDEC of a Remedial Design work plan for this site and has recorded an estimated minimum liability for remediation of this site of $15.7 million.

(ii) Other

In June 2007, the NYDEC notified the Company, as well as a number of other companies, of their potential liability with respect to a remedial action at a waste disposal site in New York. The notification identified the Company as one of approximately 500 other companies considered to be PRPs related to this site and requested that the remedy the NYDEC proposed in a Record of Decision issued in March 2006 be performed. The estimated clean-up costs under the remedy selected by the NYDEC are estimated to be approximately $13.0 million if implemented. The Company participates in an organized group with other PRPs who are addressing this site.

Other

The Company, in its Utility segment, Energy Marketing segment, and All Other category, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. Substantially all of these contracts expire within the next five years. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $520.2 million in 2010, $101.8 million in 2011, $66.6 million in 2012, $40.2 million in 2013, $39.8 million in 2014, and $76.3 million thereafter. Gas prices within the gas purchase contracts are variable based on NYMEX prices adjusted for basis. In the Utility segment, these costs are 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 has entered into leases for the use of buildings, vehicles, construction tools, meters, computer equipment and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $5.4 million in 2010, $3.9 million in 2011, $3.3 million in 2012, $2.4 million in 2013, $2.3 million in 2014, and $10.5 million thereafter.

The Company is involved in other litigation arising in the normal course of business. In addition to the regulatory matters discussed in Note C — Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business. These other litigation and regulatory matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

Note J — Discontinued Operations

On August 31, 2007, the Company, in its Exploration and Production segment, completed the sale of SECI, Seneca's wholly owned subsidiary that operated in Canada. The Company received approximately $232.1 million of proceeds from the sale, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. In December 2007, the Canadian government issued the tax clearance certificate, thereby releasing the proceeds from restriction as of December 31, 2007. The sale resulted in the recognition of a gain of approximately $120.3 million, net of tax, during the fourth quarter of 2007. SECI engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in the provinces of Alberta, Saskatchewan and British Columbia in Canada. The decision to sell was based on lower than expected returns from the Canadian oil and gas properties combined with difficulty in finding significant new reserves. Seneca will continue its exploration and development activities in the United States, primarily in Appalachia and California. As a result of the decision to sell SECI, the Company began presenting all SECI operations as discontinued operations during the fourth quarter of 2007.

The following is selected financial information of the discontinued operations for SECI:

	Year Ended September 30, 2007
	(Thousands)
Operating Revenues	$ 50,495
Operating Expenses	33,306
Operating Income	17,189
Interest Income	1,082
Income before Income Taxes	18,271
Income Tax Expense	2,792
Income from Discontinued Operations	15,479
Gain on Disposal, Net of Taxes of $39,572	120,301
Income from Discontinued Operations	$135,780

Note K — Business Segment Information

The Company has four reportable segments: Utility, Pipeline and Storage, Exploration and Production, and Energy Marketing. The division of the Company's operations into 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 by the FERC for both Supply Corporation and Empire. 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's new facilities (the Empire Connector project), which consists of a compressor station and a pipeline extension from near Rochester, New York to an interconnection near Corning, New York with the unaffiliated Millennium Pipeline, were placed into service on December 10, 2008. Empire transports gas to major industrial companies, utilities (including Distribution Corporation) and power producers.

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, and in the Gulf Coast region of Texas and Louisiana. Seneca's production is, for the most part, sold to purchasers located in the vicinity of its wells. As disclosed in Note J — Discontinued Operations, on August 31, 2007, Seneca completed the sale of SECI, its wholly owned subsidiary operating in Canada, for a gain of approximately $120.3 million, net of tax, during the fourth quarter of 2007. As a result of the sale, SECI's operations have been reported as discontinued operations. As disclosed in Note M — Acquisition, on July 20, 2009, Seneca acquired Ivanhoe Energy's United States oil and gas operations for approximately $39.2 million (including cash acquired). Ivanhoe Energy's United States oil and gas operations were incorporated into the Company's consolidated financial statements for the period subsequent to the completion of the acquisition on July 20, 2009.

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

The data presented in the tables below reflect financial information for the 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. 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.

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	Year Ended September 30, 2009 (Thousands)							
Revenue from External Customers	$1,097,550	$ 137,478	$ 382,758	$397,763	$2,015,549	$ 41,409	$ 894	$2,057,852
Intersegment Revenues	$ 15,474	$ 81,795	$ —	$ 558	$ 97,827	$ 3,890	$(101,717)	$ —
Interest Income	$ 2,486	$ 995	$ 2,430	$ 79	$ 5,990	$ 583	$ (797)	$ 5,776
Interest Expense	$ 32,417	$ 21,580	$ 33,368	$ 215	$ 87,580	$ 2,471	$ (3,135)	$ 86,916
Depreciation, Depletion and Amortization	$ 39,675	$ 35,115	$ 90,816	$ 42	$ 165,648	$ 7,066	$ 696	$ 173,410
Income Tax Expense (Benefit)	$ 37,097	$ 30,579	$ (14,616)	$ 4,470	$ 57,530	$ (5,221)	$ (1,189)	$ 51,120
Income from Unconsolidated Subsidiaries	$ —	$ —	$ —	$ —	$ —	$ 3,366	$ —	$ 3,366
Significant Non-Cash Item: Impairment of Oil and Gas Producing Properties	$ —	$ —	$ 182,811	$ —	$ 182,811	$ —	$ —	$ 182,811
Significant Non-Cash Item: Impairment of Investment in Partnership	$ —	$ —	$ —	$ —	$ —	$ 1,804(1)	$ —	$ 1,804
Significant Non-Cash Item: Impairment of Landfill Gas Assets	$ —	$ —	$ —	$ —	$ —	$ 4,568(2)	$ —	$ 4,568
Segment Profit: Net Income (Loss)	$ 58,664	$ 47,358	$ (10,238)	$ 7,166	$ 102,950	$ (2,071)	$ (171)	$ 100,708
Expenditures for Additions to Long-Lived Assets	$ 56,178	$ 50,118	$ 223,223(3)	$ 25	$ 329,544	$ 9,723(4)	$ (47)	$ 339,220
	At September 30, 2009 (Thousands)							
Segment Assets	$2,132,610	$1,046,372	$1,265,678	$ 52,469	$4,497,129	$210,809	$ 61,191	$4,769,129

(1) Amount represents the impairment in the value of the Company's 50% investment in ESNE, a partnership that owns an 80-megawatt, combined cycle, natural gas-fired power plant in the town of North East, Pennsylvania.

(2) Amount represents the impairment in the value of certain long-lived landfill gas site assets due to the loss of a primary customer at the site and the anticipated shut-down of the site. The impairment includes a $2.6 million reduction in intangible assets related to long-term gas purchase contracts and a $2.0 million reduction in property, plant and equipment.

(3) Amount includes the acquisition of Ivanhoe Energy's United States oil and gas operation for $34.9 million, net of cash acquired, and is discussed in Note M — Acquisition.

(4) Amount includes a $1.3 million capital contribution made by NFG Midstream Processing, LLC in the Whitetail Processing Plant.

	Year Ended September 30, 2008							
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers	$1,194,657	$135,052	$ 466,760	$549,932	$2,346,401	$ 53,265	$ 695	$2,400,361
Intersegment Revenues	$ 15,612	$ 81,504	$ —	$ 1,300	$ 98,416	$ 14,115	$(112,531)	$ —
Interest Income	$ 1,836	$ 843	$ 10,921	$ 323	$ 13,923	$ 1,232	$ (4,340)	$ 10,815
Interest Expense	$ 27,683	$ 13,783	$ 41,645	$ 175	$ 83,286	$ 3,782	$ (13,099)	$ 73,969
Depreciation, Depletion and Amortization	$ 39,113	$ 32,871	$ 92,221	$ 42	$ 164,247	$ 5,687	$ 689	$ 170,623
Income Tax Expense (Benefit)	$ 36,303	$ 34,008	$ 92,686	$ 3,180	$ 166,177	$ 2,186	$ (441)	$ 167,922
Income from Unconsolidated Subsidiaries	$ —	$ —	$ —	$ —	$ —	$ 6,303	$ —	$ 6,303
Segment Profit: Net Income (Loss)	$ 61,472	$ 54,148	$ 146,612	$ 5,889	$ 268,121	$ 5,779	$ (5,172)	$ 268,728
Expenditures for Additions to Long-Lived Assets	$ 57,457	$165,520	$ 192,187	$ 39	$ 415,203	$ 1,485	$ (2,186)	$ 414,502

	At September 30, 2008 (Thousands)							
Segment Assets	$1,643,665	$948,984	$1,416,120	$ 89,527	$4,098,296	$217,874	$(185,983)	$4,130,187

	Year Ended September 30, 2007							
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers	$1,106,453	$130,410	$ 324,037	$413,612	$1,974,512	$ 64,282	$ 772	$2,039,566
Intersegment Revenues	$ 14,271	$ 81,556	$ —	$ —	$ 95,827	$ 8,726	$(104,553)	$ —
Interest Income	$ (2,345)	$ 357	$ 9,905	$ 682	$ 8,599	$ 1,265	$ (8,314)	$ 1,550
Interest Expense	$ 28,190	$ 9,623	$ 51,743	$ 263	$ 89,819	$ 5,952	$ (21,296)	$ 74,475
Depreciation, Depletion and Amortization	$ 40,541	$ 32,985	$ 78,174	$ 33	$ 151,733	$ 5,494	$ 692	$ 157,919
Income Tax Expense	$ 31,642	$ 35,740	$ 52,421	$ 5,654	$ 125,457	$ 4,465	$ 1,891	$ 131,813
Income from Unconsolidated Subsidiaries	$ —	$ —	$ —	$ —	$ —	$ 4,979	$ —	$ 4,979
Segment Profit: Income from Continuing Operations	$ 50,886	$ 56,386	$ 74,889	$ 7,663	$ 189,824	$ 6,292	$ 5,559	$ 201,675
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 54,185	$ 43,226	$ 146,687	$ 76	$ 244,174	$ 7,044(1)	$ (319)	$ 250,899

	At September 30, 2007 (Thousands)							
Segment Assets	$1,565,593	$810,957	$1,326,073	$ 59,802	$3,762,425	$231,755	$(105,768)	$3,888,412

(1) Amount includes a $3.3 million capital contribution to Seneca Energy by Horizon Power.

Geographic Information	For The Year Ended September 30 2009	2008	2007
		(Thousands)	
Revenues from External Customers(1):			
United States	$2,057,852	$2,400,361	$2,039,566

	At September 30		
	2009	2008	2007
		(Thousands)	
Long-Lived Assets:			
United States	$3,992,159	$3,630,709	$3,334,274

(1) Revenue is based upon the country in which the sale originates. This table excludes revenues from Canadian discontinued operations of $50,495 for September 30, 2007.

Note L — Investments in Unconsolidated Subsidiaries

The Company's unconsolidated subsidiaries consist of equity method investments in Seneca Energy, Model City, ESNE and Whitetail Processing Plant. The Company has 50% interests in each of the first three entities and a 35% ownership interest in the Whitetail Processing Plant. 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. Whitetail Processing Plant is currently under construction with completion expected in the fall of 2009. Once completed, the plant will extract natural gas liquids from local production in Pennsylvania.

During the quarter ended December 31, 2008, the Company recorded a pre-tax impairment of $1.8 million ($1.1 million on an after-tax basis) of its equity investment in ESNE due to a decline in the fair market value of ESNE. The impairment was driven by a significant decrease in "run time" for the plant given the economic downturn and the resulting decrease in demand for electric power.

A summary of the Company's investments in unconsolidated subsidiaries at September 30, 2009 and 2008 is as follows:

	At September 30	
	2009	2008
	(Thousands)	
Seneca Energy	$10,924	$10,589
Model City	2,136	1,732
ESNE	1,880	3,958
Whitetail Processing Plant	1,317	—
	$16,257	$16,279

Note M — Acquisition

On July 20, 2009, the Company's wholly-owned subsidiary in the Exploration and Production segment, Seneca, acquired all of the shares of Ivanhoe Energy's United States oil and gas operations for approximately $39.2 million in cash (including cash acquired), of which $2.0 million was held in escrow at September 30, 2009. In accordance with the purchase agreement, this amount will remain in escrow for one year from the closing of the transaction provided there are no pending disputes or actions regarding obligations and liabilities required to be satisfied or discharged by Ivanhoe Energy. Ivanhoe Energy's United States oil and gas operations were incorporated into the Company's consolidated financial statements for the period subsequent to the completion of the acquisition on July 20, 2009. As of the acquisition date, these assets produced approximately 645 (595 net) barrels per day of oil in California and Texas. The purchase also included certain exploration acreage in California. This acquisition adds to the Company's existing oil producing assets in the Midway Sunset Field in California. The acquisition consisted of approximately $37.1 million in property, plant and equipment,

$6.2 million of current assets (including $2.0 million of cash held in escrow), $0.3 million of current liabilities and $3.8 million of deferred credits. Details of the acquisition are as follows (all figures in thousands):

Assets Acquired	$43,282
Liabilities Assumed	(4,082)
Cash Acquired at Acquisition	(4,267)
Cash Paid, Net of Cash Acquired	$34,933

Note N — Intangible Assets

As a result of the Empire and Toro acquisitions in 2003, the Company acquired certain intangible assets. 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 (in thousands):

	At September 30, 2009			At September 30, 2008
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Net Carrying Amount
Intangible Assets Subject to Amortization:				
Long-Term Transportation Contracts	$ 4,701	$ (2,630)	$ 2,071	$ 2,522
Long-Term Gas Purchase Contracts	31,864	(12,399)	19,465	23,652
	$36,565	$(15,029)	$21,536	$26,174
Aggregate Amortization Expense:				
For the Year Ended September 30, 2009	$ 4,638			
For the Year Ended September 30, 2008	$ 2,662			
For the Year Ended September 30, 2007	$ 2,662			

In September 2009, the Company recorded a pre-tax impairment of $4.6 million in the value of certain long-lived assets in the All Other category due to the loss of the primary customer at one of Toro's landfill gas sites and the anticipated shut-down of the site. The impairment was comprised of a $2.6 million reduction in intangible assets related to long-term gas purchase contracts and a $2.0 million reduction in property, plant and equipment. The $2.6 million intangible assets impairment was recorded to Purchased Gas expense and the $2.0 million property, plant and equipment impairment was recorded to Depreciation, Depletion and Amortization expense on the Consolidated Statement of Income. The $2.6 million impairment of the intangible asset is included in amortization expense for the year ended September 30, 2009 in the table shown above.

In October 2008, the Company completed the amortization of intangible assets related to two long-term transportation contracts. As such, the gross carrying amount of intangible assets subject to amortization was reduced from $8.6 million at September 30, 2008 to $4.7 million at September 30, 2009. Accumulated amortization was reduced by the same amount. Aside from this change, the only activity with regard to intangible assets subject to amortization was amortization expense as shown in the table above. Amortization expense for the long-term transportation contracts is estimated to be $0.4 million annually for 2010, 2011, 2012, 2013 and 2014. Amortization expense for the long-term gas purchase contracts is estimated to be $1.4 million annually for 2010, 2011, 2012, 2013 and 2014.

Note O — 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 Statements of Income. Those per common share amounts are based on the weighted average number of shares outstanding for the entire fiscal year. Because of the seasonal nature of the Company's heating business, there are substantial variations in operations reported on a quarterly basis.

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) Available for Common Stock	Earnings per Common Share Basic	Earnings per Common Share Diluted
	(Thousands, except per common share amounts)				
2009					
9/30/2009	$278,933	$ 64,922	$ 26,998(1)	$ 0.34	$ 0.33
6/30/2009	$367,111	$ 88,086	$ 42,904	$ 0.54	$ 0.53
3/31/2009	$804,645	$138,642	$ 73,484	$ 0.92	$ 0.92
12/31/2008	$607,163	$ (66,820)	$(42,678)(2)	$(0.54)	$(0.53)
2008					
9/30/2008	$397,858	$ 79,149	$ 43,266	$ 0.54	$ 0.52
6/30/2008	$548,382	$110,947	$ 59,855	$ 0.74	$ 0.72
3/31/2008	$885,853	$170,020	$ 95,003(3)	$ 1.14	$ 1.11
12/31/2007	$568,268	$126,009	$ 70,604	$ 0.84	$ 0.82

(1) Includes a non-cash $4.6 million impairment charge ($2.8 million after tax) associated with landfill gas assets in the All Other category.

(2) Includes a non-cash $182.8 million impairment charge ($108.2 million after tax) associated with the Exploration and Production segment's oil and gas producing properties; a non-cash $1.8 million impairment charge ($1.1 million after tax) associated with an equity investment in the All Other category and a $2.3 million gain realized on life insurance policies in the Corporate category.

(3) Includes a $0.6 million gain on the sale of a turbine.

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

At September 30, 2009, there were 16,098 registered shareholders 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 E — 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, 2009 and 2008, are shown below:

Quarter Ended	Price Range High	Price Range Low	Dividends Declared
2009			
9/30/2009	$48.30	$33.77	$.335
6/30/2009	$37.61	$29.83	$.335
3/31/2009	$34.34	$26.67	$.325
12/31/2008	$41.99	$26.83	$.325
2008			
9/30/2008	$60.36	$39.16	$.325
6/30/2008	$63.71	$47.00	$.325
3/31/2008	$48.78	$38.04	$ .31
12/31/2007	$50.29	$45.20	$ .31

Note Q — Supplementary Information for Oil and Gas Producing Activities (unaudited)

The following supplementary information is presented in accordance with the authoritative guidance regarding 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 2009	At September 30 2008
	(Thousands)	
Proved Properties(1)	$1,953,720	$1,783,276
Unproved Properties	70,061	23,285
	2,023,781	1,806,561
Less — Accumulated Depreciation, Depletion and Amortization	990,284	718,166
	$1,033,497	$1,088,395

(1) Includes asset retirement costs of $65.9 million and $60.9 million at September 30, 2009 and 2008, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Following is a summary of costs excluded from amortization at September 30, 2009:

	Total as of September 30, 2009	Year Costs Incurred 2009	2008	2007	Prior
		(Thousands)			
Acquisition Costs	$63,708	$44,728	$6,342	$2,361	$10,277
Development Costs	6,353	6,353	—	—	—
	$70,061(1)	$51,081	$6,342	$2,361	$10,277

(1) Costs related to unproved properties excluded from amortization includes $52.3 million related to onshore properties and $17.8 million related to offshore properties at September 30, 2009.

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

	Year Ended September 30 2009	2008	2007
		(Thousands)	
United States			
Property Acquisition Costs:			
Proved	$ 35,803	$ 16,474	$ 2,621
Unproved	44,528	8,449	3,210
Exploration Costs	11,724	56,274	26,891
Development Costs	125,109	106,975	113,206
Asset Retirement Costs	2,877	20,048	2,139
	220,041	208,220	148,067
Canada — Discontinued Operations			
Property Acquisition Costs:			
Proved	—	—	(1,404)
Unproved	—	—	(1,142)
Exploration Costs	—	—	20,134
Development Costs	—	—	11,414
Asset Retirement Costs	—	—	167
	—	—	29,169
Total			
Property Acquisition Costs:			
Proved	35,803	16,474	1,217
Unproved	44,528	8,449	2,068
Exploration Costs	11,724	56,274	47,025
Development Costs	125,109	106,975	124,620
Asset Retirement Costs	2,877	20,048	2,306
	$220,041	$208,220	$177,236

For the years ended September 30, 2009, 2008 and 2007, the Company spent $24.2 million, $25.4 million and $30.3 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2009	2008	2007
	(Thousands, except per Mcfe amounts)		
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $239, $443 and $325, respectively)	$106,815	$216,623	$135,399
Oil, Condensate and Other Liquids	174,356	305,887	189,539
Total Operating Revenues(1)	281,171	522,510	324,938
Production/Lifting Costs	62,614	66,685	48,410
Accretion Expense	5,437	4,056	3,704
Depreciation, Depletion and Amortization ($2.10, $2.23 and $1.97 per Mcfe of production)	89,307	91,093	77,452
Impairment of Oil and Gas Producing Properties(2)	182,811	—	—
Income Tax Expense (Benefit)	(27,055)	144,922	78,928
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	(31,943)	215,754	116,444
Canada — Discontinued Operations			
Operating Revenues:			
Natural Gas	—	—	39,114
Oil, Condensate and Other Liquids	—	—	10,313
Total Operating Revenues(1)	—	—	49,427
Production/Lifting Costs	—	—	14,846
Accretion Expense	—	—	249
Depreciation, Depletion and Amortization ($1.67 per Mcfe of production for 2007)	—	—	12,787
Income Tax Expense	—	—	3,703
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	—	—	17,842

	Year Ended September 30		
	2009	2008	2007
	(Thousands, except per Mcfe amounts)		
Total			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $239, $443 and $325, respectively)	106,815	216,623	174,513
Oil, Condensate and Other Liquids	174,356	305,887	199,852
Total Operating Revenues(1)	281,171	522,510	374,365
Production/Lifting Costs	62,614	66,685	63,256
Accretion Expense	5,437	4,056	3,953
Depreciation, Depletion and Amortization ($2.10, $2.23 and $1.92 per Mcfe of production)	89,307	91,093	90,239
Impairment of Oil and Gas Producing Properties(2)	182,811	—	—
Income Tax Expense	(27,055)	144,922	82,631
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$ (31,943)	$215,754	$134,286

(1) Exclusive of hedging gains and losses. See further discussion in Note G — Financial Instruments.

(2) See discussion of impairment in Note A — Summary of Significant Accounting Policies.

Reserve Quantity Information

The Company's proved oil and gas reserves are located in the United States. 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 (Discontinued Operations)	Total Company
Proved Developed and Undeveloped Reserves:						
September 30, 2006	41,802	75,866	81,373	199,041	33,534	232,575
Extensions and Discoveries	3,577	—	29,676	33,253	1,333	34,586
Revisions of Previous Estimates	(9,851)	1,238	1,618	(6,995)	11,634	4,639
Production	(10,356)	(3,929)	(5,555)	(19,840)	(6,426)	(26,266)
Sales of Minerals in Place	(36)	—	(34)	(70)	(40,075)	(40,145)
September 30, 2007	25,136	73,175	107,078	205,389	—	205,389
Extensions and Discoveries	8,759	—	31,322	40,081	—	40,081
Revisions of Previous Estimates	2,156	566	(3,460)	(738)	—	(738)
Production	(11,033)	(4,039)	(7,269)	(22,341)	—	(22,341)
Purchases of Minerals in Place	—	4,539	727	5,266	—	5,266
Sales of Minerals in Place	(377)	(1,381)	—	(1,758)	—	(1,758)
September 30, 2008	24,641	72,860	128,398	225,899	—	225,899
Extensions and Discoveries	6,698	3,282	49,249	59,229	—	59,229
Revisions of Previous Estimates	9,407	488	(19,484)	(9,589)	—	(9,589)(1)
Production	(9,886)	(4,063)	(8,335)	(22,284)	—	(22,284)
Purchases of Minerals in Place	—	392	—	392	—	392
Sales of Minerals in Place	(4,693)	—	—	(4,693)	—	(4,693)
September 30, 2009	26,167	72,959	149,828	248,954	—	248,954
Proved Developed Reserves:						
September 30, 2006	32,345	64,196	81,373	177,914	33,534	211,448
September 30, 2007	25,136	66,017	96,674	187,827	—	187,827
September 30, 2008	18,242	68,453	115,824	202,519	—	202,519
September 30, 2009	18,051	67,603	120,579	206,233	—	206,233

(1) During 2009, the Company made a downward revision of its proved developed and undeveloped reserves amounting to 9,589 MMcf. This was primarily attributable to a 19,484 MMcf reduction in the Appalachian

region offset by a 9,407 MMcf increase in the Gulf Coast region. The reduction in the Appalachian region was mainly due to declining natural gas prices, which made certain reserves uneconomical. The improvement in the Gulf Coast region was due to improved performance of Gulf Coast properties.

	Oil Mbbl					
	U. S.					
	Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada (Discontinued Operations)	Total Company
Proved Developed and Undeveloped Reserves:						
September 30, 2006	1,244	54,869	273	56,386	1,632	58,018
Extensions and Discoveries	63	—	281	344	108	452
Revisions of Previous Estimates	851	(6,822)	84	(5,887)	(76)	(5,963)
Production	(717)	(2,403)	(124)	(3,244)	(206)	(3,450)
Sales of Minerals in Place	(6)	—	(7)	(13)	(1,458)	(1,471)
September 30, 2007	1,435	45,644	507	47,586	—	47,586
Extensions and Discoveries	298	471	58	827	—	827
Revisions of Previous Estimates	203	(34)	(64)	105	—	105
Production	(505)	(2,460)	(105)	(3,070)	—	(3,070)
Purchases of Minerals in Place	—	2,084	—	2,084	—	2,084
Sales of Minerals in Place	(73)	(1,261)	—	(1,334)	—	(1,334)
September 30, 2008	1,358	44,444	396	46,198	—	46,198
Extensions and Discoveries	302	896	15	1,213	—	1,213
Revisions of Previous Estimates	447	43	(41)	449	—	449
Production	(640)	(2,674)	(59)	(3,373)	—	(3,373)
Purchases of Minerals in Place	—	2,115	—	2,115	—	2,115
Sales of Minerals in Place	(15)	—	—	(15)	—	(15)
September 30, 2009	1,452	44,824	311	46,587	—	46,587
Proved Developed Reserves:						
September 30, 2006	1,217	42,522	273	44,012	1,632	45,644
September 30, 2007	1,435	36,509	483	38,427	—	38,427
September 30, 2008	1,313	37,224	357	38,894	—	38,894
September 30, 2009	1,194	37,711	285	39,190	—	39,190

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

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		
	2009	2008	2007
		(Thousands)	
United States			
Future Cash Inflows	$3,972,026	$5,845,214	$4,879,496
Less:			
Future Production Costs	1,010,851	1,231,705	872,536
Future Development Costs	312,717	265,515	229,987
Future Income Tax Expense at Applicable Statutory Rate	916,466	1,645,351	1,423,707
Future Net Cash Flows	1,731,992	2,702,643	2,353,266
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	856,015	1,434,799	1,292,804
Standardized Measure of Discounted Future Net Cash Flows	$ 875,977	$1,267,844	$1,060,462

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

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
United States			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	$1,267,844	$1,060,462	$ 861,659
Sales, Net of Production Costs	(218,557)	(455,825)	(276,529)
Net Changes in Prices, Net of Production Costs	(699,217)	509,705	539,895
Purchases of Minerals in Place	38,902	67,768	—
Sales of Minerals in Place	(20,141)	(31,642)	484
Extensions and Discoveries	66,002	143,394	98,751
Changes in Estimated Future Development Costs	(22,392)	(100,684)	(83,199)
Previously Estimated Development Costs Incurred	53,285	65,156	58,710
Net Change in Income Taxes at Applicable Statutory Rate	331,251	(119,585)	(174,920)
Revisions of Previous Quantity Estimates	(27,864)	(3,936)	(140,203)
Accretion of Discount and Other	106,864	133,031	175,814
Standardized Measure of Discounted Future Net Cash Flows at End of Year	875,977	1,267,844	1,060,462

	Year Ended September 30		
	2009	2008	2007
		(Thousands)	
Canada — Discontinued Operations			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	—	—	74,249
Sales, Net of Production Costs	—	—	(34,581)
Net Changes in Prices, Net of Production Costs	—	—	35,628
Sales of Minerals in Place	—	—	(151,236)
Extensions and Discoveries	—	—	6,908
Changes in Estimated Future Development Costs	—	—	5,722
Previously Estimated Development Costs Incurred	—	—	5,798
Net Change in Income Taxes at Applicable Statutory Rate	—	—	(10,075)
Revisions of Previous Quantity Estimates	—	—	34,998
Accretion of Discount and Other	—	—	32,589
Standardized Measure of Discounted Future Net Cash Flows at End of Year	—	—	—
Total			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	1,267,844	1,060,462	935,908
Sales, Net of Production Costs	(218,557)	(455,825)	(311,110)
Net Changes in Prices, Net of Production Costs	(699,217)	509,705	575,523
Purchases of Minerals in Place	38,902	67,768	—
Sales of Minerals in Place	(20,141)	(31,642)	(150,752)
Extensions and Discoveries	66,002	143,394	105,659
Changes in Estimated Future Development Costs	(22,392)	(100,684)	(77,477)
Previously Estimated Development Costs Incurred	53,285	65,156	64,508
Net Change in Income Taxes at Applicable Statutory Rate	331,251	(119,585)	(184,995)
Revisions of Previous Quantity Estimates	(27,864)	(3,936)	(105,205)
Accretion of Discount and Other	106,864	133,031	208,403
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$ 875,977	$1,267,844	$1,060,462

Note R — Subsequent Events

In accordance with the authoritative guidance for subsequent events, the Company has evaluated subsequent events through November 25, 2009, which represents the filing date of this Form 10-K with the SEC, in order to ensure that this Form 10-K includes appropriate disclosure of events both recognized in the financial statements as of September 30, 2009, and events which occurred subsequent to September 30, 2009 but were not recognized in the financial statements. As of November 25, 2009, there were no subsequent events which required recognition or disclosure.

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, 2009					
Allowance for Uncollectible Accounts	$33,117	$31,464	$2,751	$28,998	$38,334
Year Ended September 30, 2008					
Allowance for Uncollectible Accounts	$28,654	$27,274	$2,734	$25,545	$33,117
Year Ended September 30, 2007					
Allowance for Uncollectible Accounts	$31,427	$27,652	$1,414	$31,839	$28,654

(1) Represents the discount on accounts receivable purchased in accordance with the Utility segment's 2005 New York rate agreement.

(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*

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the 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 or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, 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 Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2009.

Management's Annual Report on Internal Control over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2009. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework*. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2009.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2009. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended September 30, 2009 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, Executive Officers and Corporate Governance*

The information required by this item concerning the directors of the Company and corporate governance is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2010

Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2009. The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled "Nominees for Election as Directors for Three-Year Terms to Expire in 2013," "Directors Whose Terms Expire in 2012," "Directors Whose Terms Expire in 2011," and "Section 16(a) Beneficial Ownership Reporting Compliance" and is incorporated herein by reference. The information concerning corporate governance is set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" 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.

The Company intends to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of its code of ethics that applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, and that relates to any element of the code of ethics definition enumerated in paragraph (b) of Item 406 of the SEC's Regulation S-K, by posting such information on its website, www.nationalfuelgas.com.

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 2010 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2009. The information concerning executive compensation will be set forth in the definitive Proxy Statement under the headings "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee," 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 2010 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2009. The equity compensation plan information will be set forth in the definitive Proxy Statement under the heading "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 2010 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2009. The information concerning security ownership of certain beneficial owners will be set forth in the definitive Proxy Statement under the heading "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 2010 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2009. The information concerning security ownership of management will be set forth in the definitive Proxy Statement under the heading "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, and Director Independence*

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 2010 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2009. The information regarding certain relationships and related transactions will be set forth in the definitive Proxy Statement under the headings "Compensation Committee Interlocks and Insider Participation" and "Related Person Transactions" and is incorporated herein by reference. The information regarding director independence is set forth in the definitive Proxy Statement under the heading "Director Independence" 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 2010 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2009. The information concerning principal accountant fees and services will be set forth in the definitive Proxy Statement under the heading "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)
•	Certificate of Amendment of Restated Certificate of Incorporation (Exhibit 3(ii), Form 8-K dated March 14, 2005 in File No. 1-3880)
3(ii)	By-Laws:
•	National Fuel Gas Company By-Laws as amended June 11, 2008 (Exhibit 3.1, Form 8-K dated June 16, 2008 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)
•	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)
•	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)
•	Officer's Certificate establishing 6.50% Notes due 2018, dated April 11, 2008 (Exhibit 4.1, Form 10-Q for the quarterly period ended June 30, 2008 in File No. 1-3880)
•	Officer's Certificate establishing 8.75% Notes due 2019, dated April 6, 2009 (Exhibit 4.4, Form 8-K dated April 6, 2009 in File No. 1-3880)
•	Amended and Restated Rights Agreement, dated as of December 4, 2008, between the Company and The Bank of New York, as rights agent (Exhibit 4.1, Form 8-K dated December 4, 2008 in File No. 1-3880)
10	Material Contracts:
•	Credit Agreement, dated as of August 19, 2005, among the Company, the Lenders Party Thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
•	Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006 in File No. 1-3880)
•	Settlement Agreement dated January 24, 2008 among the Company, New Mountain Vantage GP, L.L.C. ("Vantage") and certain of Vantage's affiliates (Exhibit 10.1, Form 8-K dated January 24, 2008 in File No. 1-3880)
•	Director Services Agreement, dated as of June 1, 2008, between the Company and Philip C. Ackerman (Exhibit 99, Form 8-K dated June 16, 2008 in File No. 1-3880)
•	Agreement to Extend Duration of Director Services Agreement, dated June 1, 2009, between the Company and Philip C. Ackerman (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2009 in File No. 1-3880)
•	Resolutions adopted by the National Fuel Gas Company Board of Directors on February 21, 2008 regarding director stock ownership guidelines (Exhibit 10.5, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880)
	Management Contracts and Compensatory Plans and Arrangements:

Exhibit Number	Description of Exhibits
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and each of Karen M. Camiolo, Carl M. Carlotti, Anna Marie Cellino, Paula M. Ciprich, Donna L. DeCarolis, John R. Pustulka, James D. Ramsdell, David F. Smith and Ronald J. Tanski (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008 in File No. 1-3880)
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, Seneca Resources Corporation and Matthew D. Cabell (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2008 in File No. 1-3880)
•	Letter Agreement between the Company and Matthew D. Cabell, dated November 17, 2006 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
10.1	Description of September 17, 2009 restricted stock award
10.2	Description of post-employment medical and prescription drug benefits
•	National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated March 28, 2005 in File No. 1-3880)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated May 16, 2006 in File No. 1-3880)
•	Form of Restricted Stock Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
•	Form of Stock Option Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2008 in File No. 1-3880)
•	Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
•	Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2008 in File No. 1-3880)
•	Description of performance goals for certain executive officers under the Company's Annual At Risk Compensation Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2007 in File No. 1-3880)
•	Description of performance goals for certain executive officers under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2008 in File No. 1-3880)
•	National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.4, Form 10-K for the fiscal year ended September 30, 2008 in File No. 1-3880)
•	Description of performance goals for an executive officer under the Company's Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2008 in File No. 1-3880)
•	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective February 20, 2008 (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 2008 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)

Exhibit Number	Description of Exhibits

- 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)
- 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)
- 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)
- 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)
- Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
- Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 2005 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)
- Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
- National Fuel Gas Company Tophat Plan, Amended and Restated December 7, 2005 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2005 in File No. 1-3880)
- National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007 in File No. 1-3880)
- Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- 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)
- Life Insurance Premium Agreement, dated September 17, 2009, between the Company and David F. Smith (Exhibit 10.1, Form 8-K dated September 23, 2009 in File No. 1-3880)
- National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880)
- National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)

Exhibit Number	Description of Exhibits

- Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
- Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001, in File No. 1-3880)
- National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of January 1, 2007 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
- National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 20, 2007 (Exhibit 10.4, Form 10-K for the fiscal year ended September 30, 2007 in File No. 1-3880)
- National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008 in File No. 1-3880)
- National Fuel Gas Company and Participating Subsidiaries 1996 Executive Retirement Plan Trust Agreement (II), dated May 10, 1996 (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- National Fuel Gas Company Participating Subsidiaries Executive Retirement Plan 2003 Trust Agreement(I), dated September 1, 2003 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880)
- National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 8-K dated June 3, 2005 in File No. 1-3880)
- Excerpts of Minutes from the National Fuel Gas Company Board of Directors Meeting of March 20, 1997 regarding the Retainer Policy for Non-Employee Directors (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2009 in File No. 1-3880)
- Amended and Restated Retirement Benefit Agreement for David F. Smith, dated September 20, 2007, among the Company, National Fuel Gas Supply Corporation and David F. Smith (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2007 in File No. 1-3880)
- Description of assignment of interests in certain life insurance policies (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880)
- Description of long-term performance incentives under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880)
- Description of long-term performance incentives under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2008 in File No. 1-3880)
- Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880)
- Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2006 in File No. 1-3880)

Exhibit Number	Description of Exhibits
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 2005 through 2009
21	Subsidiaries of the Registrant
23	Consents of Experts:
23.1	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
23.2	Consent of Independent Registered Public Accounting Firm
31	Rule 13a-14(a)/15d-14(a) Certifications:
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
32	Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99	Additional Exhibits:
99.1	Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
99.2	Company Maps
•	Incorporated herein by reference as indicated.
	All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K
••	In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference

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/ D. F. Smith

D. F. Smith
President and Chief Executive Officer

Date: November 25, 2009

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

Signature	Title	
/s/ P. C. Ackerman P. C. Ackerman	Chairman of the Board and Director	Date: November 25, 2009
R. T. Brady	Director	Date:
/s/ R. D. Cash R. D. Cash	Director	Date: November 25, 2009
/s/ S. E. Ewing S. E. Ewing	Director	Date: November 25, 2009
/s/ R. E. Kidder R. E. Kidder	Director	Date: November 25, 2009
/s/ C. G. Matthews C. G. Matthews	Director	Date: November 25, 2009
/s/ G. L. Mazanec G. L. Mazanec	Director	Date: November 25, 2009
/s/ R. G. Reiten R. G. Reiten	Director	Date: November 25, 2009
/s/ F. V. Salerno F. V. Salerno	Director	Date: November 25, 2009
/s/ D. F. Smith D. F. Smith	President, Chief Executive Officer and Director	Date: November 25, 2009

Signature	Title	
/s/ R. J. Tanski R. J. Tanski	Treasurer and Principal Financial Officer	Date: November 25, 2009
/s/ K. M. Camiolo K. M. Camiolo	Controller and Principal Accounting Officer	Date: November 25, 2009

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Principal Officers

National Fuel Gas Company

David F. Smith, President and Chief Executive Officer

Ronald J. Tanski, Treasurer and Principal Financial Officer

Karen M. Camiolo, Controller and Principal Accounting Officer

Paula M. Ciprich, General Counsel and Secretary

Donna L. DeCarolis, Vice President Business Development

Principal Officers of Principal Subsidiaries

Seneca Resources Corporation

David F. Smith, Chairman

Matthew D. Cabell, President

Barry L. McMahan, Senior Vice President and Secretary

John P. McGinnis, Senior Vice President

National Fuel Gas Supply Corporation

David F. Smith, Chairman

Ronald J. Tanski, President

John R. Pustulka, Senior Vice President

David P. Bauer, Treasurer

James R. Peterson, Secretary

Karen M. Camiolo, Controller

Ronald C. Kraemer, Vice President

Empire Pipeline, Inc.

David F. Smith, Chairman

Ronald C. Kraemer, President

David P. Bauer, Treasurer

James R. Peterson, Secretary

Karen M. Camiolo, Controller

National Fuel Gas Distribution Corporation

David F. Smith, Chairman

Anna Marie Cellino, President

James D. Ramsdell, Senior Vice President

Carl M. Carlotti, Senior Vice President

Richard E. Klein, Treasurer

Paula M. Ciprich, Secretary

Karen M. Camiolo, Controller

Bruce D. Heine, Vice President

Jay W. Lesch, Vice President

Steven Wagner, Vice President

National Fuel Resources, Inc.

Joseph N. Del Vecchio, Vice President

Directors

Philip C. Ackerman 3ˆ, 5ˆ – Chairman of the Board of Directors of the Company since January 2002. Former Chief Executive Officer and President of the Company. Chair of the Erie County (NY) Industrial Development Authority. Director of Associated Electric and Gas Insurance Services Limited. Board member since 1994.

Robert T. Brady 2, 3, 4ˆ – Chairman, President and Chief Executive Officer of Moog Inc. Director of Astronics Corporation, M&T Bank Corporation and Seneca Foods Corporation. Director of the Buffalo Niagara Partnership and the Albright-Knox Art Gallery. Board member since 1995.

R. Don Cash 1, 2, 4 – Chairman Emeritus and Director of Questar Corporation. Former Chairman, Chief Executive Officer and President of Questar Corporation. Chairman of TT Foundation. Director of Zions Bancorporation, Associated Electric and Gas Insurance Services Limited, Texas Tech Foundation and Ranching Heritage Association. Board member since 2003.

Stephen E. Ewing 1, 2, 5 – Former Vice Chairman of DTE Energy Corp. Former President and Chief Operating Officer of MCN Energy Group Inc. and Former President and Chief Executive Officer of Michigan Consolidated Gas Company. Director of the Auto Club Group and Auto Club Services, Inc. (AAA) and CMS Energy Corporation. Trustee and Board Chair of the Skillman Foundation. Board member since 2007.

Rolland E. Kidder 1, 4 – Founder, former Chair and President of Kidder Exploration, Inc., and former Trustee of the New York Power Authority. Former Director of two Appalachian-based energy associations: the Independent Oil and Gas Association of New York and the Pennsylvania Natural Gas Associates. Board member since 2002.

Craig G. Matthews 1ˆ, 3, 5 – Former President and Chief Executive Officer of NUI Corporation. Former Vice Chairman and Chief Operating Officer of KeySpan Corporation. Board member of Hess Corp. and Republic Financial Corp. Board member and past Chairman of Board of Trustees of Polytechnic University and National Greater New York and New Jersey Salvation Army. Board member since February 2005.

George L. Mazanec 1, 2ˆ, 3, 5 – Former Vice Chairman of PanEnergy Corporation (now Spectra Energy Corp.). Director of Dynegy Inc. and Associated Electric and Gas Insurance Services Limited. Member of the Board of Trustees of DePauw University. Board member since 1996.

Richard G. Reiten 2, 4 – Former Director, Chairman and Chief Executive Officer of Northwest Natural Gas Company and Former Director, President and Chief Operating Officer of Portland General Electric Company. Also Director of Associated Electric and Gas Insurance Services Limited, IDACORP Inc. and U.S. Bancorp. Board member since 2004.

Frederic V. Salerno 2, 4 – Former Vice Chairman and CFO of Verizon Communications. Director of Akamai Technologies Inc., Intercontinental Exchange, Inc., Popular, Inc., Viacom, Inc. and CBS Corporation. Board member since 2008.

David F. Smith 3 – President and Chief Executive Officer of National Fuel Gas Company since February 2008. Director of The Business Council of New York State, Buffalo Niagara Enterprise (Chairman), American Gas Association (Executive Committee), American Gas Foundation and GTI (Executive Committee). Board member since 2007.

1 Member of Audit Committee
2 Member of Compensation Committee
3 Member of Executive Committee
4 Member of Nominating/ Corporate Governance Committee
5 Member of Financing Committee
ˆ Denotes Committee Chairman

Investor Information

Common Stock Transfer Agent and Registrar
BNY Mellon Shareowner Services
P.O. Box 358015
Pittsburgh, PA 15252-8015
Tel. (800) 648-8166
Website: http://www.bnymellon.com/shareowner/isd
E-mail: shrrelations@bnymellon.com

Change of address notices and inquiries about dividends should be sent to the Transfer Agent at the address listed above.

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 Mellon, the administrator of the Plan, at the address listed above for BNY Mellon Shareowner Services.

Trustee for Debentures
The Bank of New York Mellon
101 Barclay Street
New York, NY 10286

Stock Exchange Listing
New York Stock Exchange (Stock Symbol: NFG)

The Company's Chief Executive Officer filed with the New York Stock Exchange on April 7, 2009, the certification required by Section 303A.12(a) of the NYSE Listed Company Manual. In addition, the most recent certifications by the Company's Chief Executive Officer and Principal Financial Officer pursuant to Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 were filed as exhibits to the Company's Form 10-K for the fiscal year ended September 30, 2009.

Annual Meeting
The Annual Meeting of Stockholders will be held at 10:00 a.m. (local time) on Thursday, March 11, 2010, at The Grand America Hotel, 555 South Main Street, Salt Lake City, UT, 84111. Stockholders of record as of the close of business on January 15, 2010 will receive in the mail formal notice of the meeting, proxy statement and proxy.

Investor Relations
Investors or financial analysts desiring information should contact:

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

James C. Welch, Director, Investor Relations
Tel. (716) 857-6987
E-mail: welchj@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 2009 Annual Report can be obtained without charge by writing to or calling:

Paula M. Ciprich, Corporate Secretary
Tel. (716) 857-7548

James C. Welch, Director, Investor Relations
Tel. (716) 857-6987

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

Independent Accountants
PricewaterhouseCoopers LLP
3600 HSBC Center
Buffalo, NY 14203

National Fuel

National Fuel Gas Company | 6363 Main Street, Williamsville, New York 14221 | (716) 857-7000 | nationalfuelgas.com | NYSE: NFG