RGC RESOURCES INC
Form ARS
December 20, 2006

Exhibit 13

Total operating revenue for RGC Resources, Inc. increased $7,721,083, or 8%, for 2006, with the average per unit cost of natural gas increasing by 17% for regulated operations.

FINANCIAL HIGHLIGHTS

Year Ended September 30,	**2006**	**2005**	**2004**
Operating Revenue - Natural Gas	**$ 106,912,988**	$ 99,196,587	$ 83,703,964
Other Revenue	**$ 884,762**	$ 880,080	$ 621,005
Net Income - Continuing Operations	**$ 3,274,594**	$ 3,147,640	$ 1,905,388
Net Income - Discontinued Operations	**$ 236,937**	$ 359,266	$ 11,028,625
Basic Earnings Per Share - Continuing Operations	**$ 1.55**	$ 1.52	$ 0.94
Basic Earnings Per Share - Discontinued Operations	**0.11**	0.17	5.44*
Regular Dividend Per Share - Cash	**$ 1.20**	$ 1.18	$ 1.17
Number of Customers - Natural Gas	**59,305**	58,946	58,081
Total Natural Gas Deliveries - DTH	**10,482,865**	11,452,388	11,903,920
Total Additions to plant	**$ 7,867,336**	$ 7,427,304	$ 7,925,948

* Reflects $4.69 gain on sales of assets.

NUMBER OF CUSTOMERS

NATURAL GAS

(in thousands)

DIVIDEND PER SHARE

(in dollars,

excluding special dividend)

THE DISCOVERY OF A NEW DISH DOES MORE FOR THE HAPPINESS OF THE HUMAN RACE

THAN THE DISCOVERY OF A STAR.

JEAN ANTHELME BRILLAT-SAVARIN

I am pleased to report company earnings of $3.5 million or $1.65 per average diluted share outstanding on total company operations and $3.3 million or $1.54 on continuing operations for the fiscal year.

TO OUR SHAREHOLDERS:

I am pleased to report company earnings of $3.5 million or $1.65 per average diluted share outstanding on total company operations and $3.3 million or $1.54 on continuing operations for the fiscal year. The $1.54 on continuing operations represents a $0.03 per share improvement over 2005 and a $0.61 per share improvement over 2004. Given that the 2006 fiscal year had 12% fewer heating degree days than the 30-year normal used for rate design and that a spike in natural gas prices led to customer conservation measures, I believe the Company performed well under adverse conditions. I am also pleased to report that our Board of Directors elected to increase the annualized dividend rate to $1.22 per share effective with the February 1, 2007 quarterly dividend for shareholders of record on January 12, 2007. The February 1, 2007 dividend will reflect our ninth annual dividend increase since 1995 and continues 62 years of consecutive quarterly dividend payments to shareholders.

Total natural gas delivered volumes decreased by almost 1 million decatherms, or 8%, compared to 2005, on 2% fewer heating degree days, reflecting the impact of warmer winter weather as well as customer conservation and fuel switching. Natural gas prices, which already reflected the effect of tight supplies, jumped from $7 a decatherm in the late summer of 2005 to $14 a decatherm in October 2005, an all-time high, after damage from hurricanes Katrina and Rita temporarily shut down nearly 90% of the Gulf region natural gas production. An unusually mild winter, combined with the industry s rapid recovery of production capacity, allowed for adequate supplies to meet the nation s winter needs and led to a decline in the Henry Hub price of natural gas to below $8 per decatherm by March 2006. The industry and the nation avoided the serious problems that would have resulted from a very cold winter or a slower recovery from the Gulf region supply interruption. We did, however, learn two clear lessons. First, customers, including homeowners, do reduce energy consumption when prices rise significantly, and second, the nation s concentration of supply development in the Gulf region is an industry and national vulnerability.

Congress clearly needs to respond to this vulnerability by lifting the ban on off-shore drilling for natural gas on the east and west U.S. outer continental shelves, off the west coast of Florida,

AH! THERE IS NOTHING LIKE STAYING HOME FOR REAL COMFORT.

- JANE AUSTEN

In addition, because natural gas is a much cleaner burning fuel than coal or fuel oil, virtually all new electricity generation facilities utilize natural gas, further increasing the nation s reliance on adequate natural gas supplies.

and in other restricted areas of the mountainous west. In addition, the Alaskan natural gas pipeline needs to be built to bring stranded natural gas supply to the lower 48 states. All of these new sources will take years to develop, so further congressional delay only increases the likelihood of another price and supply shock if Gulf region production facilities are materially impacted by future hurricanes or gas production declines due to resource depletion. In addition, because natural gas is a much cleaner burning fuel than coal or fuel oil, virtually all new electricity generation facilities utilize natural gas, further increasing the nation s reliance on adequate natural gas supplies. RGC Resources, directly and through its membership in the American Gas Association, continues to urge Congressional action. We encourage our shareholders, employees, and trade allies to express that same concern to their elected representatives. We are confident that natural gas will remain the nation s fuel of choice for a reliable, efficient, and cleaner energy source; however, we also believe that Congress and the nation need to make informed and timely decisions to increase access to new areas for natural gas exploration and production to insure adequate supplies and more stable prices.

Locally, we continued our efforts to enhance the reliability, safety and integrity of our natural gas distribution systems through pipeline system upgrades. We also continued our system expansion and customer growth. We replaced approximately eight miles of bare steel or cast iron main with new coated steel or plastic pipeline, and we installed over seven miles of new main, adding approximately 1,200 new connections. Given the initial negative customer reactions to the gas price spike, and the slowing new housing construction market, I was pleased with the level of service additions for fiscal 2006.

As is typically the case, replacing older distribution pipeline with new facilities results in increased depreciation expense and higher carrying cost on the incremental investment. Consequently, we filed for base rate increases in West Virginia in January 2006 and in Virginia in September 2006. A final order was received in the West Virginia case in late 2006 and new rates were placed into effect in November, after the end of the 2006 fiscal year. The Virginia case, while pending a Commission final decision, provided for new rates effective in October, subject to refund. We expect to receive a final order and to make customer refunds, if necessary, in mid 2007.

OH, THE FUN OF ARRIVING AT A HOUSE AND FEELING THE SPARK THAT TELLS YOU

THAT YOU ARE GOING TO HAVE A GOOD TIME.

MARK HAMPTON

We continued to focus on our core natural gas utility distribution operations with a decision to exit the unregulated natural gas marketing business with the sale of Highland Energy in July.

We continued to focus on our core natural gas utility distribution operations with a decision to exit the unregulated natural gas marketing business with the sale of Highland Energy in July. Given the very thin margins in the natural gas marketing business along with the increased price risk and customer credit risk associated with volatile prices, we decided to monetize the remaining value of our gas marketing contracts and to redeploy the capital from the marketing operations into the regulated utility distribution system.

We continued our program for compliance with Sarbanes-Oxley federal legislation, particularly section 404 related to internal controls which, under current Securities and Exchange Commission (SEC) and Public Company Accounting Oversight Board (PCAOB) interpretation and enforcement, will require a separate external audit of the Company s internal controls as well as attestation of the adequacy of such controls by both management and the independent auditors. There is an ongoing national debate regarding the appropriateness, necessity, and unusually high cost for the added regulatory burden of the Sarbanes-Oxley legislation. The new United States Secretary of the Treasury, Henry Paulson, has strongly urged a more reasoned approach by the SEC and PCAOB on accounting and auditing rules to lessen the burdensome and costly impact, particularly on smaller companies.

We are positioning RGC Resources to comply with the new internal controls rules, while attempting to not over-invest time, talent, and resources for a regulatory regime that may change if a more reasoned approach can be developed. We have undertaken an internal review and controls documentation process as well as enhanced our risk mitigation programs, up to and including exiting the unregulated gas marketing business to reduce risk. The implications of excessive regulation and overzealous accounting and auditing rules on the competitiveness of U.S. publicly traded firms and U.S. stock exchanges is becoming obvious to most market observers. I believe this is evidenced by the growing number of public firms electing to go private and newer firms planning initial public offerings selecting a foreign exchange rather than the New York Stock Exchange or Nasdaq to avoid the current SEC and PCAOB regulatory model.

We are pleased to provide you with our 2006 annual report representing 123 years of delivering efficient, reliable, and safe gas service and 63 years of operations as a publicly-owned

Our customers have come to expect, and we believe deserve, our continuing commitment to ensuring their safe and economical access to the nation s preferred energy source to comfortably heat their homes, cook their meals, and fuel their businesses.

and locally managed company. Our customers have come to expect, and we believe deserve, our continuing commitment to ensuring their safe and economical access to the nation s preferred energy source to comfortably heat their homes, cook their meals, and fuel their businesses. We are delighted to maintain the high level of service to which they have become accustomed.

On behalf of the Board of Directors and employees of RGC Resources, Inc., I thank you for your interest in our operations and for your continuing decision to be a shareholder of RGC Resources. We still offer a dividend reinvestment and stock purchase plan, free of commission or transaction fees, for shareholders that desire automatic reinvestment of part or all of their dividends or wish to make additional direct purchases of stock through the plan. Please contact us at 540-777-3853, or go to our web site at www.RGCResources.com, if you would like more information on the program.

Sincerely,

John B. Williamson, III
Chairman, President and CEO

Selected Financial Data

Years Ended September 30,	**2006**	**2005**	**2004**	**2003**	**2002**
Operating Revenues	**$ 107,797,750**	$ 100,076,667	$ 84,324,969	$ 75,742,816	$ 58,203,586
Operating Margin	**26,065,443**	24,760,821	23,126,378	21,633,183	19,256,583
Operating Income	**7,705,861**	7,126,083	4,929,724	5,000,870	4,712,917
Net Income - Continuing Operations	**3,274,594**	3,147,640	1,905,388	1,823,218	1,771,705
Net Income - Discontinued Operations	**236,937**	359,266	11,028,625	1,705,171	715,190
Basic Earnings Per Share- Continuing Operations	**$ 1.55**	$ 1.52	$ 0.94	$ 0.92	$ 0.91
Basic Earnings Per Share- Discontinued Operations	**0.11**	0.17	5.44*	0.86	0.37
Cash Dividends Declared Per Share	**$ 1.20**	$ 1.18	$ 5.67	$ 1.14	$ 1.14
Book Value Per Share	**18.94**	18.18	17.73	16.90	16.36
Average Shares Outstanding	**2,120,267**	2,079,851	2,027,908	1,983,970	1,939,511
Total Assets	**114,662,572**	113,563,416	114,972,556	104,364,733	96,978,115
Long-Term Debt (Less Current Portion)	**30,000,000**	30,000,000	26,000,000	30,219,987	30,377,358
Stockholders Equity	**40,494,868**	38,157,357	36,621,522	33,857,614	32,068,997
Shares Outstanding at Sept. 30	**2,138,595**	2,098,935	2,065,408	2,003,232	1,960,418

* Reflects $4.69 gain on sale of assets.

FORWARD-LOOKING STATEMENTS

From time to time, RGC Resources, Inc. (Resources or the Company) may publish forward-looking statements relating to such matters as anticipated financial performance, business prospects, technological developments, new products, research and development activities and similar matters. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements. In order to comply with the terms of the safe harbor, the Company notes that a variety of factors could cause the Company s actual results and experience to differ materially from the anticipated results or other expectations expressed in the Company s forward-looking statements. The risks and uncertainties that may affect the operations, performance, development and results of the Company s business include the following: (i) failure to earn on a consistent basis an adequate return on invested capital; (ii) ability to retain and attract professional and technical employees; (iii) price competition from alternative fuels; (iv) volatility in the price and availability of natural gas; (v) uncertainty in the projected rate of growth of natural gas requirements in the Company s service area; (vi) general economic conditions both locally and nationally; (vii) increases in interest rates; (viii) increased customer delinquencies and conservation efforts resulting from high fuel costs and/or colder weather; (ix) developments in electricity and natural gas deregulation and associated industry restructuring; (x) variations in winter heating degree-days from normal; (xi) changes in environmental requirements, pipeline operating requirements and cost of compliance; (xii) impact of potential increased regulatory oversight and compliance requirements due to financial, environmental, safety and system integrity laws and regulations; (xiii) failure to obtain timely rate relief for increasing operating or gas costs from regulatory authorities; (xiv) ability to raise debt or equity capital; (xv) impact of terrorism; (xvi) volatility in actuarially determined benefit costs; (xvii) impact of natural disasters on production and distribution facilities and the related effect on supply availability and price; and (xviii) new accounting standards issued by the Financial Accounting Standards Board, which could change the accounting treatment for certain transactions. All of these factors are difficult to predict and many are beyond the Company s control. Accordingly, while the Company believes its forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. When used in the Company s documents or news releases, the words, anticipate, believe, intend, plan, estimate, expect, objective, projection, forecast , budge or future or conditional verbs such as will, would, should, could or may are intended to identify forward-looking statements. Forward-lookin statements reflect the Company s current expectations only as of the date they are made. The Company assumes no duty to update these statements should expectations change or actual results differ from current expectations except as required by applicable laws and regulations.

Management s Discussion & Analysis

GENERAL

Resources is an energy services company primarily engaged in the regulated sale and distribution of natural gas to approximately 59,300 residential, commercial and industrial customers in Roanoke, Virginia and Bluefield, Virginia and West Virginia and the surrounding areas through its Roanoke Gas Company and Bluefield Gas Company subsidiaries. Natural gas service is provided at rates and for the terms and conditions set forth by the State Corporation Commission (SCC or Virginia Commission) in Virginia and the Public Service Commission (PSC or West Virginia Commission) in West Virginia. Roanoke Gas and Bluefield Gas currently hold the only franchises and/or certificates of public convenience and necessity to distribute natural gas in its Virginia and West Virginia service areas. These franchises are effective through January 1, 2016 in Virginia and August 23, 2009 in West Virginia. While there are no assurances, the Company believes that it will be able to negotiate acceptable franchises when the current agreements expire. Certificates of public convenience and necessity in Virginia are exclusive and are intended to be of perpetual duration.

Resources also provided unregulated energy products through Diversified Energy Company, which operated as Highland Energy Company. Highland Energy brokered natural gas to several industrial and commercial transportation customers of Roanoke Gas and Bluefield Gas. On July 10, 2006, Diversified Energy Company entered into an asset purchase agreement for the sale of its energy marketing operations. These operations as such are classified as discontinued operations. Please see the Discontinued Operations section below for further discussion. In addition to an energy marketing company, Diversified Energy Company operated an unregulated propane operation under the name of Highland Propane Company, which was sold in July 2004.

Winter weather conditions and volatility in natural gas prices both have a direct influence on the quantity of natural gas sales to the Company s customers and management believes each factor has the potential to significantly impact earnings. A majority of natural gas sales are for space heating during the winter season. Consequently, during warmer than normal winters, customers may significantly reduce their purchase of natural gas.

The Company has been able to mitigate a portion of the risk associated with warmer than normal winter weather by the inclusion of a weather normalization adjustment (WNA) factor as part of Roanoke Gas Company s rate structure. The WNA factor operates based on a weather occurrence band around the most recent 30-year temperature average for the Company s service area. The weather band provision utilizes an approximate 6% range around normal weather, whereby if the number of heating degree-days (an industry measure by which the average daily temperature falls below 65 degrees Fahrenheit) fall within approximately 6% above or below the 30-year average, no adjustment would be made. However, if the number of heating degree-days were more than 6% below the 30-year average, the Company would add a surcharge to firm customer bills (those customers not subject to service interruption) equal to the equivalent margin lost below the approximate 6% level. Likewise, if the number of heating degree-days were more than 6% above the 30-year average, the Company would credit firm customer bills equal to the excess margin realized above the 6% heating degree-day level. The measurement period in determining the weather band extends from April through March with any adjustment to be made to customer bills in late spring. The heating degree-days for the period April 2005 through March 2006 were approximately 11% less than the 30-year average. As the level of degree-days fell outside the 6% band, the Company recorded approximately $327,000 in additional revenues to reflect the lost margin between 11% warmer and 6% warmer weather and billed customers accordingly. For the period April 2004 through March 2005, the heating degree-days were approximately 12% less than the 30-year average. As a result, the Company recognized approximately $445,000 in additional revenues.

Management also has concerns regarding the volatility of natural gas prices and the potential for reduced sales in response to increasing prices. Rising natural gas prices may influence the level of sales due to conservation efforts by customers or may result in switching to an alternative fuel. In addition, increasing prices may increase the level of bad debts due to customers inability to afford the higher prices. Although current natural gas prices are well below the prices that occurred in the fall of 2005 following damage to natural gas production and transportation facilities from Hurricanes Katrina and Rita, the Company is concerned about the potential lingering effects that high prices may have on customers ongoing conservation efforts. The Company directly experienced the effect of customers energy conservation efforts in the past winter season; however, the carryover effect of conservation practices for the upcoming winter season is not known.

For the fiscal year ended September 30, 2006, the Company experienced a decline in sales volumes due to warmer winter weather and the effect of customer conservation efforts during the heating season. The effect of the warmer weather on the results of operations was partially mitigated due to the application of the weather normalization adjustment as discussed above, while a non-gas rate increase placed into effect in October 2005 and an increased level of carrying cost revenues partially offset reduced sales volumes due to conservation efforts. More information regarding these items is provided below.

RESULTS OF OPERATIONS CONTINUING OPERATIONS

Fiscal Year 2006 Compared With Fiscal Year 2005

Delivered Volumes - The table below reflects volume activity and heating degree-days.

Year Ended September 30,	**2006**	**2005**	**Increase/ (Decrease)**	**Percentage**
Regulated Natural Gas (DTH)				
Tariff Sales	**7,590,818**	8,209,107	(618,289)	-8%
Transportation	**2,892,047**	3,243,281	(351,234)	-11%
Total	**10,482,865**	11,452,388	(969,523)	-8%
Heating Degree-Days (Unofficial)	**3,714**	3,783	(69)	-2%

Tariff sales, primarily consisting of residential and commercial usage, declined 8% due to a decrease in heating degree-days and conservation. Transporting volumes, which correlate more with economic factors and business decisions rather than weather, reflected a reduction of 11% from the same period last year. The reduction in transporting volumes appears to be related to a combination of fuel switching and other economic factors. Nearly half of the reduction in transporting volumes relates to one industrial customer that has converted a majority of its processes to utilize coal to lower energy costs. Most of the remaining reduction is related to production activities and certain smaller industrial transportation customers closing their operations in the Roanoke area.

Operating Revenues - The table below reflects operating revenues.

Year Ended September 30,	**2006**	**2005**	**Increase/ (Decrease)**	**Percentage**
Gas Utilities	**$ 106,912,988**	$ 99,196,587	$ 7,716,401	8%
Other	**884,762**	880,080	4,682	1%
Total Operating Revenues	**$ 107,797,750**	$ 100,076,667	$ 7,721,083	8%

Total operating revenue increased $7,721,083, or 8%, for the year ended September 30, 2006 (fiscal 2006) compared to the year ended September 30, 2005 (fiscal 2005). The increase in operating revenues resulted from higher natural gas costs reflected in the billing rates and the implementation of base rate increases. The average per unit cost of natural gas increased by 17% for regulated operations.

Gross Margin - The table below reflects gross margins.

Year Ended September 30,	2006	2005	Increase/ (Decrease)	Percentage
Gas Utilities	**$ 25,712,411**	$ 24,263,694	$ 1,448,717	6%
Other	**353,032**	497,127	(144,095)	-29%
Total Gross Margin	**$ 26,065,443**	$ 24,760,821	$ 1,304,622	5%

Total gross margin increased by $1,304,622, or 5%, over fiscal 2005. Regulated natural gas margins increased by $1,448,717, or 6%, even though total delivered volume (tariff and transporting) decreased by 969,523 decatherms, or 8%. The decline in delivered tariff volumes was attributable in part to weather that had 2% fewer heating degree-days; however, the greater impact surrounding the decline in volume resulted from customers energy conservation presumably in response to high natural gas prices during the winter period. Transportation sales deliveries, composed of large industrial customers, declined by 11% due to energy costs and other economic factors as discussed above. Even though delivered volumes declined, the regulated natural gas margin increased due to non-gas cost rate increases and the recovery of the financing costs (carrying costs) related to rising interest rates and higher average dollar investments in storage gas inventories. Both Roanoke Gas Company and Bluefield Gas Company placed increased non-gas rates into effect during the first quarter of fiscal 2006. Roanoke Gas Company s rates were placed into effect subject to refund pending a final order from the Virginia Commission. Bluefield Gas Company s rates were placed into effect in accordance with a final rate order issued by the West Virginia Commission. The rate increases provided for both a higher customer base charge, the flat monthly fee billed to each natural gas customer, and volumetric rate. As a result, customer base charges increased by approximately $412,000 and volumetric margins increased by approximately $593,000, including the impact of reduced sales volumes and lower WNA billings. Carrying cost revenues increased by approximately $403,000 due to a combination of higher average storage gas inventory during the current fiscal year and rising interest rates.

Both Roanoke Gas and Bluefield Gas had approved rate structures in place during the year that allowed each company to accrue revenue to cover the financing costs related to the level of investment in natural gas inventory. During this time of rising gas costs and rising inventory levels, both companies recognized revenues to offset the higher financing costs. Conversely, the companies would have passed along savings to customers if financing costs had decreased due to lower inventory gas balances resulting from reductions in gas costs or volumes. The net effect of increased investment of gas in storage resulted in an approximately $403,000 increase in revenues and margin. Due to much warmer weather during the last two heating seasons, natural gas storage volumes have remained at higher levels than expected. As a result, carrying cost revenues have been at a higher level than would normally be expected. During periods of declining gas costs and storage gas levels, the Company will experience a reduction in carrying cost revenues and margins as well. As a result of an order by West Virginia Commission in Bluefield Gas Company s 2006 rate case, Bluefield will no longer calculate a separate carrying cost revenue based on natural gas storage balances beginning in November 2006. Instead, these revenues will be included as part of the base non-gas rates and will only be adjusted as a result of future rate case filings.

Other margins decreased by $144,095 due to the expiration of the services agreement to provide billing, facility and other services to the acquirer of Highland Propane Company.

TOTAL CAPITALIZATION

(in millions)

Other Operating Expenses Operations expenses increased $384,427, or 4%, in fiscal 2006 compared with fiscal 2005 primarily as a result of higher employee benefit costs, which more than offset reductions in bad debt expense. Employee benefit costs increased due to higher health care, pension and postretirement benefit expenses. The Company had been self-insured for medical insurance purposes for the past several years with stop/loss coverage only for extremely high claim activity. The self-insurance program generated volatility in expense due to fluctuating claim levels. During the quarter ended December 31, 2004, claims expense was unusually low. In January 2005, the Company switched to fully insured coverage to provide a more predictable expense trend, which has reduced volatility between reporting periods but resulted in approximately $165,000 in higher cost in the first quarter of fiscal 2006 compared to fiscal 2005. The Company also experienced an increase of approximately $436,000 attributable to its pension and postretirement medical plan due to the actuarial effect of a lower discount rate used in expense and liability calculations as well as the adoption of new mortality tables. Both pension and postretirement medical expense for fiscal 2007 are expected to be below fiscal 2006 levels due to the effect of a higher discount rate used in the actuarial calculations combined with the level of plan funding and return on plan assets. Bad debt expense declined by approximately $130,000 as fiscal 2005 bad debt expense included a $200,000 reserve related to a commercial customer that management believed would have difficulty in paying its obligation. In addition, the Company completed the three-year amortization of the regulatory asset established in fiscal 2002 related to unusually high level of bad debt expense resulting in a reduction of $88,000 in operating expenses.

Maintenance expenses decreased by $25,629, or 2%, as the level of leak repairs, facility maintenance and transmission right-of-way clearing were comparable with the prior fiscal year.

General taxes increased $148,586, or 10%, in fiscal 2006 compared to fiscal 2005 due to higher business and occupation (B&O) taxes, a revenue-sensitive tax related to the West Virginia natural gas operations and increased property taxes associated with greater levels of taxable property.

Depreciation expense increased $217,460, or 5% due to capital expenditures associated with system expansion for adding new natural gas customers and pipeline and facility renewal projects.

Other expenses, net, decreased $47,736 as a result of a greater level of interest income on temporary cash investments in fiscal 2006 and the loss on retirement of a propane air facility in fiscal 2005.

Interest Expense Total interest expense for fiscal 2006 increased $453,333, or 22%, from fiscal 2005, as both the total average debt outstanding during the year increased by 10% while the average effective interest rate on total debt increased from 5.7% to 6.2%.

Debt Summary:

Year Ended September 30,	2006	2005	Increase/ (Decrease)	Percentage
Average Daily Balance:				
Long-term Fixed Rate Debt	**$ 27,275,708**	$ 24,000,000	$ 3,275,708	14%
Long-term Variable Rate Debt	**2,000,000**	2,000,000		0%
Short-term Variable Rate Debt	**8,728,178**	8,497,216	230,962	3%
Total Variable Rate Debt	**10,728,178**	10,497,216	230,962	2%
Total Debt	**38,003,886**	34,497,216	3,506,670	10%
Average Interest Rate:				
Long-term Fixed Rate Debt	**6.72%**	6.79%	-0.07%	-1%
Variable Rate Debt	**5.23%**	3.34%	1.89%	57%

The increase in interest expense was attributable to a combination of higher average outstanding debt balances and increasing interest rates. The higher debt balance resulted from the refinancing of the $8,000,000 unsecured note due November 30, 2005, $3,000,000 collateralized term debenture due in 2016 and $4,000,000 in line-of-credit into a $15,000,000 five year unsecured variable rate note with a corresponding interest rate swap. The result of the refinancing provided for an effective long-term interest rate consistent with the prior year. The increase in interest rates on short-term and variable rate debt is attributable to Federal Reserve policy designed to control inflation. The average effective interest rate on the Company s variable rate lines-of-credit and Bluefield Gas unsecured note increased by 189 basis points, or 57%, over last year.

Income Taxes Income tax expense from continuing operations increased $47,227, or 2% over fiscal 2005 as pre-tax earnings reflected an increase. The effective tax rate for fiscal 2006 was 37.2% compared to 37.6% in fiscal 2005.

Net Income and Dividends Income from continuing operations for fiscal 2006 was $3,274,594 as compared to fiscal 2005 income from continuing operations of $3,147,640. The improvement in income from continuing operations derived from the non-gas cost rate increase and increased carrying cost revenues, which more than offset the impact of warmer winter weather, the effect of customer energy conservation and higher operation expenses. Basic and diluted earnings per share from continuing operations were $1.55 and $1.54 in fiscal 2006 compared with $1.52 and $1.51 in fiscal 2005, respectively. Dividends per share of common stock were $1.20 in fiscal 2006 and $1.18 in fiscal 2005.

Fiscal Year 2005 Compared With Fiscal Year 2004

Delivered Volumes The table below reflects volume activity and heating degree-days.

Year Ended September 30,	2005	2004	Increase/ (Decrease)	Percentage
Regulated Natural Gas (DTH)				
Tariff Sales	8,209,107	8,466,916	(257,809)	-3%
Transportation	3,243,281	3,437,004	(193,723)	-6%
Total	11,452,388	11,903,920	(451,532)	-4%
Heating Degree-Days (Unofficial)	3,783	3,917	(134)	-3%

Operating Revenues The table below reflects operating revenues.

Year Ended September 30,	2005	2004	Increase/ (Decrease)	Percentage
Gas Utilities	$ 99,196,587	$ 83,703,964	$ 15,492,623	19%
Other	880,080	621,005	259,075	42%
Total Operating Revenues	$ 100,076,667	$ 84,324,969	$ 15,751,698	19%

Total operating revenue increased $15,751,698, or 19%, for the year ended September 30, 2005 (fiscal 2005) compared to the year ended September 30, 2004 (fiscal 2004). The increase in operating revenues resulted from significantly higher natural gas costs, the implementation of base rate increases and the services agreement associated with the sale of the assets of Highland Propane Company. The average per unit cost of natural gas increased by 27% for regulated operations over fiscal 2004. Other revenues increased by $259,075 due to revenues generated under the services agreement to provide billing, facility and other services to the Acquiror of the assets of Highland Propane Company. As discussed below, the services agreement was terminated prior to the end of the 2005 fiscal year.

Gross Margin The table below reflects gross margin.

Year Ended September 30,	2005	2004	Increase/ (Decrease)	Percentage
Gas Utilities	$ 24,263,694	$ 22,833,506	$ 1,430,188	6%
Other	497,127	292,872	204,255	70%
Total Gross Margin	$ 24,760,821	$ 23,126,378	$ 1,634,443	7%

Total gross margin increased $1,634,443, or 7%, for fiscal 2005 compared to fiscal 2004. Regulated natural gas margins increased $1,430,188, or 6%, as total delivered volumes decreased by 4% due to warmer winter weather. Tariff sales, composed mainly of weather sensitive residential and commercial volumes, declined by 3%. This decline in tariff sales primarily resulted from a 3% decline in heating degree-days from fiscal 2004. Furthermore, total heating degree-days for fiscal 2005 were 10% below the 30-year normal. Transportation services, consisting of delivered volumes of natural gas purchased from other than the regulated utilities, and generally correlated more with economic conditions, decreased 6%, primarily related to an industrial customer converting a portion of its processes to utilize coal to reduce energy costs.

Although total natural gas deliveries declined by 4%, regulated natural gas margins increased due to Commission approved non-gas cost rate increases placed into effect on October 23, 2004 by Roanoke Gas Company, combined with the rate design which provides timely recovery of the financing costs (carrying costs) related to the higher dollar investments in natural gas inventories and the WNA revenues. Both Roanoke Gas Company and Bluefield Gas Company placed increased rates into effect during the first quarter of fiscal 2005. Roanoke Gas Company s rates were placed into effect subject to refund pending a final order from the Virginia Commission. Bluefield Gas Company s rates were placed into effect in accordance with a final rate order issued by the West Virginia Commission. As a result of the rate increases, the Company realized approximately $459,000 in additional customer base charges. Carrying cost revenues increased by approximately $685,000 due to a much higher level of investment in storage gas inventory compared to prepaid gas service for the same period in fiscal 2004 resulting from the combination of higher prices and warmer weather reducing the withdrawal rates from storage. The balance of the increase in regulated natural gas margin was attributable to the volumetric portion of the rate increase and $445,000 in WNA revenues both of which combined to more than offset the impact of lower volumes.

Other margins increased by $204,255, or 70%, due to the services agreement with the Acquiror of the assets of Highland Propane Company to provide billing, facility and other services as discussed in Discontinued Operations. This agreement has been terminated.

Other Operating Expenses Operations expenses decreased $494,824, or 4%, in fiscal 2005 compared with fiscal 2004 primarily as a result of lower employee benefit costs and the absence of debt retirement costs. Employee benefit costs decreased by $383,188, as a result of reduced pension costs and postretirement medical costs due to an increase in the actuarial discount rate assumption used for fiscal 2005 expense calculations and lower medical insurance claim activity in the first quarter of fiscal 2005. Postretirement medical costs were also reduced by the actuarial impact of Medicare Part D, whereby the Company reduced its postretirement medical liability due to the benefits to be provided under Medicare Part D beginning in 2006 for those plans that offer actuarially equivalent drug coverage to the Medicare Plan. The Company had been self-insured for medical insurance purposes for the past several years with stop/loss coverage in place for extremely high claims. The self-insurance program generated volatility in expense due to fluctuating claim levels. In January 2005, the Company switched to fully insured coverage to provide a more predictable expense trend. Operations expense also decreased by $125,547 associated with an early termination fee paid in fiscal 2004 for the retirement of a fixed rate note for Highland Propane. In addition, the net operations portion of bad debt expense increased $60,513, or 13%, over fiscal 2004 on higher gross revenues. Gross bad debt expense actually increased by $197,254 over fiscal 2004; however, effective November 1, 2004, in accordance with a rate order from the PSC, Bluefield Gas Company began charging the gas cost component of bad debt expense to gas cost. The result of this change allowed the Company to recover the gas cost portion of bad debt expense directly through the PGA factor rather than through a formal non-gas cost rate filing. For the year ended September 30, 2005, Bluefield Gas Company charged $136,741 of bad debt expense to gas cost.

Maintenance expenses decreased by $240,640, or 14%, as fiscal 2004 included a substantial amount of maintenance on exposed distribution gas mains, primarily bridge crossings, consisting of painting and wrapping exposed mains to prevent corrosion, the disposal of certain old and obsolete inventory of maintenance materials no longer considered useful and additional facility buildings and ground maintenance.

General taxes increased $35,572, or 2%, in fiscal 2005 compared to fiscal 2004 due to higher business and occupation (B&O) taxes, a revenue sensitive tax related to the West Virginia natural gas operations and increased property taxes associated with greater levels of taxable property.

Depreciation expense increased $137,976, or 4% due to capital expenditures associated with system expansion for adding new natural gas customers and pipeline and facility renewal projects.

Other expenses, net, increased $40,797 primarily due to loss on retirement of a propane air facility. For both fiscal 2005 and 2004, the other expense, net was reduced by investment income associated with the proceeds from the sale of the propane operations. The Company utilized these funds for debt reduction and the payment of the $4.50 per share special dividend on December 8, 2004.

Interest Expense Total interest expense for fiscal 2005 increased $141,557, or 8%, from fiscal 2004, although total average debt outstanding during the year decreased by 1%.

Debt Summary:

Year Ended September 30,	2005	2004	Increase/ (Decrease)	Percentage
Average Daily Balance:				
Long-term Fixed Rate Debt	24,000,000	23,688,524	311,476	1%
Long-term Variable Rate Debt	2,000,000	2,000,000		0%
Short-term Variable Rate Debt	8,497,216	9,224,905	(727,689)	-8%
Total Variable Rate Debt	10,497,216	11,224,905	(727,689)	-6%
Total Debt	34,497,216	34,913,429	(416,213)	-1%
Average Interest Rate:				
Long-term Fixed Rate Debt	6.79%	6.89%	-0.10%	-1%
Variable Rate Debt	3.34%	1.92%	1.42%	74%

The increase in interest expense was attributable to rising interest rates on the Company s variable rate debt as a result of the Federal Reserve s actions. Total average debt outstanding during fiscal 2005 declined slightly from fiscal 2004; however, the average interest rate on the variable rate portion of debt increased by 142 basis points representing an increase of 74% over fiscal 2004. The above analysis does not include the $4,200,000 in Diversified Energy debt that was retired in July 2004 and the corresponding interest expense included in discontinued operations on the income statement.

Income Taxes Income tax expense from continuing operations increased $771,753, or 69% over fiscal 2004 as pre-tax earnings reflected a comparable increase. The effective tax rate for fiscal 2005 was 37.6% compared to 37.0% in fiscal 2004.

Net Income and Dividends Income from continuing operations for fiscal 2005 was $3,147,640 as compared to fiscal 2004 income from continuing operations of $1,905,388. The improvement in income from continuing operations derived from the non-gas cost rate increase, increased carrying cost revenues and the implementation of a WNA, all of which more than offset the impact of warmer winter weather. In addition, reductions in both operating and maintenance costs contributed to improved earnings. Basic and diluted earnings per share from continuing operations were $1.52 and $1.51 in fiscal 2005 compared with $0.94 and $0.93 in fiscal 2004, respectively. Dividends per share of common stock were $1.18 in fiscal 2005 and $1.17 in fiscal 2004.

DISCONTINUED OPERATIONS

On July 10, 2006, Diversified Energy Company d/b/a Highland Energy, a wholly owned subsidiary of RGC Resources, Inc. entered into an asset purchase and sale agreement for the sale of the assets relating to its energy marketing business to Atmos Energy Marketing, LLC (Atmos). The assets sold include the gas supply contracts between Highland Energy and its customers and related business records. The date of transfer was set as the date from the first meter read performed for each of the end user customers on or after August 1, 2006.

The Board of Directors approved management s plan to sell the assets and operations of Highland Energy for several reasons. Competition from other energy marketing companies was putting increasing downward pressure on the already low margins associated with the gas marketing business. Significantly rising energy prices over the last few years had increased concern over customers credit risks while increasing sales margins to compensate for the increased credit risk was not realistic in a strongly competitive market. Management concluded that the developing risk-return relationship of the energy marketing operations warranted monetizing the remaining value of existing customer service contracts and discontinuing unregulated energy marketing operations.

Highland Energy and Resources agreed with Atmos for a period of three years ending July 1, 2009 to not sell any natural gas for consumption by an existing Highland Energy customer at any facility serviced under the assigned contracts with the exception of tariff gas sales by a public utility affiliate.

The purchase price for the assets sold by Highland Energy is valued at up to $414,270. Atmos paid Highland Energy the sum of $233,216 at closing, which was recognized as a gain in 2006. The remaining $181,054 will be paid by Atmos to Highland Energy in August 2007, provided that the remaining balance to be paid will be adjusted downward on a customer by customer basis by a prescribed amount to the extent (i) the customer pursuant to an assigned contract is no longer a customer on the anniversary date and such customer was not a customer for two of the preceding twelve months, or (ii) the customer reduces their average natural gas consumption by more than 20% from current annualized levels.

As a result of the sale of the assets of Highland Energy, the Company recognized a loss of approximately $147,000 in discontinued operations related to basis intended for future gas deliveries to Highland customers. Basis is defined as the transportation cost component of the gas purchase agreements necessary for pipeline utilization to transport customer gas purchases from supplier to the distribution company s pipeline.

On July 12, 2004, Resources sold the propane assets of its subsidiary, Diversified Energy Company, d/b/a Highland Propane Company (Diversified), for approximately $28,500,000 in cash to Inergy Propane, LLC (Inergy). The sale of assets encompassed all propane plant assets (with the exception of a limited number of specific assets being retained by Diversified), the name Highland Propane, customer accounts receivable, propane gas inventory and inventory of propane related materials. The Company realized a gain of approximately $9,500,000 on the sale of assets, net of income taxes.

Concurrent with the sale of assets, the Company entered into an agreement with Inergy by which the Company would continue to provide the use of office, warehouse and storage space, and computer systems and office equipment and the utilization of Company personnel for billing, propane delivery and related services for the term of one year with an option for an additional year. Inergy notified the Company of its intent not to extend the remaining portions of the agreement and to allow the contract to expire in July 2005 with the exception of a lease agreement for access to the storage yard in Bluefield, West Virginia. For the year ended September 30, 2005, the Company realized approximately $451,000 in other revenues and $266,000 in other margin attributable to this agreement.

The asset purchase agreement did not include land and buildings owned by Diversified. Inergy leased 10 parcels of real estate consisting of bulk storage facilities and office space from Diversified with an option to purchase such parcels. Prior to the end of June

2005, Inergy executed the option to purchase the real estate and closed on all 10 parcels. The Company realized a net gain on the sale of real estate of approximately $153,000.

The activities associated with Highland Energy, the former propane real estate and the former propane operations and the corresponding gains from sales of real estate and operations have been classified as Discontinued Operations in accordance with the provisions of SFAS No. 144 *Accounting for the Impairment or Disposal of Long-Lived Assets*.

ENERGY PRICES

Energy costs represent the single largest expense of the Company with the cost of natural gas representing approximately 82% for fiscal 2006, 81% for fiscal 2005 and 77% for fiscal 2004 of the total operating expenses of the Company s natural gas utility operations.

Following the 2005 hurricane season, serious concerns arose regarding the adequacy of natural gas supplies for the winter season. Damage to natural gas production facilities from Hurricane Katrina and a cold December resulted in very high natural gas commodity prices. On December 13, 2005, the futures contracts for January 2006 deliveries peaked at $15.78 per decatherm.

Following a cold December, the remainder of the winter season and early spring were much warmer than normal resulting in higher than expected natural gas storage levels at the end of the heating season. In addition to warmer weather, the very high energy prices in December led to energy conservation on the part of natural gas customers, thereby further reducing consumption and the use of storage gas. By the end of the summer storage injection season, natural gas storage levels were at near record levels with commodity prices well below last year s levels.

To mitigate the impact of price volatility, Roanoke Gas Company and Bluefield Gas Company use a variety of hedging mechanisms. Summer storage injections and financial instruments were utilized during the past winter period and provided the Company with lower energy costs than would have been incurred through spot market purchases alone. At September 30, 2006, the Company s natural gas storage levels were near capacity with nearly 3.15 million decatherms in storage. The Company also has financially hedged 720,000 decatherms of natural gas for the 2006-07 winter period.

Natural gas costs are fully recoverable under the present regulatory Purchased Gas Adjustment (PGA) mechanisms, and increases and decreases in the cost of gas are passed through to the Company s customers.

Although rising energy prices are recoverable through the PGA mechanism for the regulated operations, high energy prices may have a negative impact on earnings through increases in bad debt expense and higher interest costs because the delay in recovering higher gas costs requires borrowing to temporarily fund receivables from customers. Roanoke Gas Company s rate structure provides a level of protection against the impact that rising energy prices may have on bad debts and carrying costs on LNG storage and gas in storage by allowing for more timely recovery of these costs. However, the rate structure will not protect the Company from increases in the rate of bad debts or increases in interest rates.

SHARES OUTSTANDING

(in million)

CAPITAL RESOURCES AND LIQUIDITY

Due to the capital intensive nature of Resources utility and energy businesses as well as the related weather sensitivity, Resources primary capital needs are the funding of its continuing construction program and the seasonal funding of its natural gas inventories and accounts receivable. The Company s construction program is primarily composed of a combination of replacing aging bare steel and cast iron pipe with new plastic or coated steel pipe and expansion of the natural gas system to meet the demands of customer growth. Total capital expenditures of continuing operations for fiscal 2006 were approximately $7.8 million allocated as follows: $7.4 for Roanoke Gas Company and $0.4 million for Bluefield Gas Company. Depreciation cash flow provided approximately $4.5 million in support of capital expenditures, or approximately 57% of the total investment. Historically, consolidated capital expenditures for continuing operations were $7.4 million in 2005 and $7.9 million in 2004. Fiscal 2004 capital expenditures also included $1.0 million for discontinued operations. It is anticipated that future capital expenditures will be funded with the combination of operating cash flow, sale of Company equity securities through the Dividend Reinvestment and Stock Purchase Plan (DRIP) and issuance of debt.

Short-term borrowing, in addition to providing capital project bridge financing, is used to finance seasonal levels of natural gas inventory and accounts receivable. From April through October, the Company purchases natural gas to build inventory for winter delivery when demand is much greater. Furthermore, a majority of the Company s sales and billings occur during the winter months resulting in a corresponding increase in accounts receivable. The following table provides a quarterly perspective of the seasonality of accounts receivable and natural gas inventory. Amounts are in thousands.

Period Ended *(in thousands)*	**Gas in Storage/ Prepaid Gas Service**	**Accounts Receivable**	**Total**
September 30, 2004	$ 17,662	$ 5,978	$ 23,640
December 31, 2004	17,136	18,938	36,074
March 31, 2005	7,800	17,437	25,237
June 30, 2005	17,037	7,746	24,783
September 30, 2005	23,465	7,442	30,907
December 31, 2005	20,914	28,928	49,842
March 31, 2006	10,850	19,862	30,712
June 30, 2006	17,887	7,129	25,016
September 30, 2006	23,332	5,217	28,549

On March 24, 2006, the Company and Wachovia Bank renewed the Company s line-of-credit agreements. The agreements maintain the same variable interest rates based upon 30-day LIBOR and continue a tiered borrowing level to accommodate the Company s seasonal borrowing demands. Due to the seasonality of the business, the Company s borrowing needs generally are at their lowest in Spring and early Summer, increase during the late Summer and Fall due to gas storage purchases and construction and reach their maximum levels in Winter as indicated by the table above. The tiered approach keeps the Company s borrowing costs to a minimum by improving the level of utilization on its line-of-credit agreements and providing increased credit availability as borrowing requirements increase. The available limits under the remaining term of the line-of-credit agreements are as follows:

Effective	**Available Line-of-Credit**
September 30, 2006	$ 26,000,000
November 16, 2006	31,000,000
February 16, 2007	24,000,000

At September 30, 2006, the Company had $6,613,000 outstanding under its available lines-of-credit. The average rates on debt outstanding under the lines-of-credit were 5.08% in 2006, 3.15% in 2005 and 1.79% in 2004. The lines do not require compensating balances. These lines-of-credit will expire March 31, 2007, unless extended. The Company anticipates being able to extend the lines-of-credit or pursue other options.

In November 2005, Roanoke Gas Company and Bluefield Gas Company each entered into agreements with financial institutions to refinance maturing debt. Roanoke Gas entered into an unsecured 5-year note with provision for annual renewals in the amount of $15,000,000. The proceeds of this note were used to refinance the $8,000,000 unsecured note due November 30, 2005 and $4,000,000 in outstanding line-of-credit balance. The remainder of the proceeds were used to call the $3,000,000 collateralized term debenture due in 2016 including a call premium. Bluefield Gas Company entered into an unsecured 31-month variable rate note in the amount of $2,000,000. The proceeds of this note were used to refinance the $2,000,000 unsecured note due November 2005. The Company entered into an interest rate swap agreement on the Roanoke Gas Company note for the purpose of fixing the interest rate at 5.74% over the total term of the note.

Short-term borrowings, together with internally generated funds, long-term debt and the sale of common stock through the Company s DRIP Plan, have been adequate to cover construction costs, debt service and dividend payments to shareholders. The Company utilizes a cash management program, which provides for daily balancing of the Company s temporary investment and short-term borrowing needs. The program allows the Company to maximize returns on temporary investments and minimize the cost of short-term borrowings. The Company anticipates such benefits to continue to be realized in the future.

Stockholders equity increased for the period by $2,337,511, primarily due to earnings and proceeds from stock issued under the DRIP Plan. The activity is summarized below:

Net income	$ 3,511,531
Dividends	(2,551,427)
DRIP	874,934
Restricted stock and stock options	124,830
Net comprehensive income	377,643
Increase in stockholders equity	$ 2,337,511

At September 30, 2006, the Company s consolidated long-term capitalization was 57% equity and 43% debt, compared to 56% equity and 44% debt at September 30, 2005.

REGULATORY AFFAIRS

On April 6, 2006, Roanoke Gas Company received a final order from the SCC approving rates designed to collect an additional $1,663,456 in annual non-gas revenues based on normal weather. The new non-gas rates replaced the rates put into effect on October 23, 2005 subject to refund. Roanoke Gas Company completed the refund of customer billings in excess of the final approved rates plus interest in June. Roanoke Gas Company also filed a new request to increase non-gas rates on September 14, 2006. These new rates, designed to provide approximately $1.7 million in additional revenues, were placed into effect on October 23, 2006 subject to refund for any differences between the implemented rates and the final rates approved by the SCC. An SCC rate order is expected in the spring of 2007.

On October 3, 2006, Bluefield Gas Company received a final order from the West Virginia Commission approving a rate increase of $337,336, based on normal weather, related to the case filed by the Company in January 2006. These new rates were effective November 16, 2006. The final order moved the revenue calculations attributable to carrying cost associated with natural gas in storage and the gas cost portion of bad debts from a gas cost component to a non-gas component of rates included in the increase above. As a result, revenue to cover these costs will only be adjusted as a result of future non-gas rate case filings and not automatically adjusted for the level and/or price on natural gas in storage, the price of natural gas included in bad debts or changes in interest rates.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

RGC Resources, Inc. s contractual obligations as of September 30, 2006 representing cash obligations that are considered to be firm commitments are as follows.

	Payment due within the year ended September 30,					
	2007	2008	2009	2010	2011	Thereafter
Lines-of-credit[1]	$ 6,613,000	$	$	$	$	$
Long term debt[1]		7,000,000			15,000,000	8,000,000
Natural gas (see below)						
Pipeline and storage capacity	10,827,540	10,557,540	10,557,540	10,557,540	10,557,540	39,476,234
Total contractual obligations	$ 17,440,540	$ 17,557,540	$ 10,557,540	$ 10,557,540	$ 25,557,540	$ 47,476,234

[1] Excludes interest payments attributable to the debt

Total available lines-of-credit are scheduled to expire on March 31, 2007, at which time the Company expects to renew the contracts. See Footnote 4 in the consolidated financial statements for additional information.

See Footnote 5 in the consolidated financial statements for more information on long-term debt.

The Company has commitments to purchase pipeline and storage capacity fees in the amount of $92,533,934 under contracts expiring at various times through the year 2020. The Company expects to recover these costs through the PGA mechanism.

The Company has commitments to purchase natural gas at market price over the next two years in the amount of 2,369,675 decatherms and 338,525 decatherms associated with the provisions of the Company s asset management agreement.

CRITICAL ACCOUNTING POLICIES

The consolidated financial statements of Resources are prepared in accordance with accounting principles generally accepted in the United States of America. The amounts of assets, liabilities, revenues and expenses reported in the Company s financial statements are affected by accounting policies, estimates and judgments that are necessary to comply with generally accepted accounting principles. Estimates used in the financial statements are derived from prior experience, statistical analysis and professional judgments. Actual results could differ from the estimates, which would affect the related amounts reported in the Company s financial statements. The following policies and estimates are important in understanding certain key components of the financial statements.

Revenue recognition Regulated utility sales and transportation revenues are based upon rates approved by the SCC for Roanoke Gas Company and the PSC for Bluefield Gas Company. The non-gas cost component of rates may not be changed without a formal rate increase application and corresponding authorization by the appropriate regulatory commission; however, the gas cost component of rates may be adjusted periodically through the PGA mechanism with approval from the respective commission. Roanoke Gas Company also has a WNA, which is designed to partially offset the impact of weather that is either more than approximately 6% warmer than normal or approximately 6% colder than normal over a 12 month period. Without the WNA, the Company s operating revenues and gross margins would have been reduced by approximately $327,000 and $445,000 for fiscal 2006 and 2005, respectively.

The Company bills its regulated natural gas customers on a monthly cycle. The billing cycle periods for most customers do not coincide with the accounting periods used for financial reporting. The Company accrues estimated revenue for natural gas delivered to customers not yet billed during the accounting period. Determination of unbilled revenue relies on the use of estimates and current and historical data. The financial statements included unbilled revenue of $1,565,727 and $1,736,976 as of September 30, 2006 and 2005.

Bad debt reserves The Company evaluates the collectibility of its accounts receivable balances based upon a variety of factors including loss history, level of delinquent account balances and general economic climate.

Retirement plans The Company offers a defined benefit pension plan (pension plan) and a postretirement medical and life insurance plan (postretirement plan) to eligible employees. The expenses and liabilities associated with these plans, as disclosed in Note 7 to the consolidated financial statements, are determined through actuarial means requiring the estimation of certain assumptions and factors. In regard to the pension plan, these factors include assumptions regarding discount rate, expected long-term rate of return on plan assets, compensation increases and life expectancies, among others. Similarly, the postretirement medical plan also requires the estimation of many of the same factors as the pension plan in addition to assumptions regarding rate of medical inflation and Medicare availability. Actual results may differ materially from the results expected from the actuarial assumptions due to changing economic conditions, volatility in interest rates and changes in life expectancy to name a few. Such differences may result in a material impact on the amount of expense recorded in future periods or the value of the obligations on the balance sheet.

The discount rate assumption was determined based upon the rates of return on high quality fixed income investments corresponding with the Company s projected benefit obligation. Based upon market conditions as of the valuation date and related market trends, the discount rate increased to 6.25% from 5.25% in fiscal 2005 and 6.25% in fiscal 2004.

The expected long-term rate of return on pension and postretirement plan assets is based on the target asset allocations for each plan and the corresponding long-term returns associated with such allocations. The target allocation for the pension plan assets is 60% equity investments and 40% fixed income investments resulting in an expected long-term rate of return of 7.5%. The target allocation for postretirement plan assets is 55% equity and 45% fixed income resulting in an expected 7% long-term rate of return.

The medical trend rate is a critical component in determining the benefit obligation under the postretirement plan. Based on actual cost trend rates and projected future trends in health care costs, the trend rate assumption was 10% for fiscal 2006 compared to 9% for fiscal 2005 and 10% for fiscal 2004, declining to 5% by the year 2011.

The following schedule reflects the sensitivity of pension costs from changes in certain actuarial assumptions, while the other components of the calculation remain constant.

Actuarial Assumption	**Change in Assumption**	**Impact on 2006 Pension Cost**	**Impact on Projected Benefit Obligation**
Discount rate	-0.25%	$ 69,000	$ 491,000
Rate of return on plan assets	-0.25%	21,000	N/A
Rate of increase in compensation	0.25%	43,000	184,000

The following schedule reflects the sensitivity of postretirement benefit costs from changes in certain actuarial assumptions, while the other components of the calculation remain constant.

Actuarial Assumption	**Change in Assumption**	**Impact on 2006 Postretirement Benefit Cost**	**Impact on Accumulated Postretirement Benefit Obligation**
Discount rate	-0.25%	$ 25,000	$ 260,000
Rate of return on plan assets	-0.25%	10,000	N/A
Health care cost trend rate	0.25%	42,000	229,000

Derivatives As discussed in the Market Risk section below, the Company may hedge certain risks incurred in the normal operation of business through the use of derivative instruments. The Company applies the requirements of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities,* which requires the recognition of derivative instruments as assets or liabilities in the Company s balance sheet at fair value. In most instances, fair value is based upon quoted futures prices for natural gas commodities and interest rate futures for interest rate swaps. Changes in the commodity and futures markets will impact the estimates of fair value in the future. Furthermore, the actual market value at the point of realization of the derivative may be significantly different from the values used in determining fair value in prior financial statements.

Regulatory accounting The Company s regulated operations follow the accounting and reporting requirements of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71). The economic effects of regulation can result in a regulated company deferring costs that have been or are expected to be recovered from customers in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this results, costs are deferred as assets in the consolidated balance sheet (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for the amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future (regulatory liabilities).

If any portion of the current regulated operations ceased to meet the criteria for application of the provisions of SFAS No. 71, the Company would remove the corresponding regulatory assets or liabilities from the consolidated balance sheets and reflect them within the consolidated statement of income and comprehensive income for the period in which the discontinuance occurred.

ASSET MANAGEMENT

Both Roanoke Gas Company and Bluefield Gas Company use a third party as an asset manager to manage its pipeline transportation and storage rights and gas supply inventories and deliveries. In return for being able to utilize the excess capacities of the transportation and storage rights, the third party pays both Roanoke Gas Company and Bluefield Gas Company a monthly utilization fee, which is used to reduce the cost of gas for their customers. The current agreements expire October 31, 2007.

ENVIRONMENTAL ISSUES

Both Roanoke Gas Company and Bluefield Gas Company, subsidiaries of RGC Resources, Inc., operated manufactured gas plants (MGPs) as a source of fuel for lighting and heating until the early 1950 s. A by-product of operating MGPs was coal tar, and the potential exists for on-site tar waste contaminants at the former plant sites. The extent of contaminants at these sites, if any, is unknown at this time. An analysis at the Bluefield Gas Company site indicates some soil contamination. The Company, with concurrence of legal counsel, does not believe any events have occurred requiring regulatory reporting. Further, the Company has not received any notices of violation or liabilities associated with environmental regulations related to the MGP sites and is not aware of any off-site contamination or pollution as a result of prior operations. Therefore, the Company has no plans for subsurface remediation at the MGP sites. Should the Company eventually be required to remediate either site, the Company will pursue all prudent and reasonable means to recover any related costs, including insurance claims and regulatory approval for rate case recognition of expenses associated with any work required. A stipulated rate case agreement between the Company and the West Virginia Public Service Commission recognized the Company s right to defer MGP clean-up costs, should any be incurred, and to seek rate relief for such costs. If the Company eventually incurs costs associated with a required clean-up of either MGP site, the Company anticipates recording a regulatory asset for such clean-up costs to be recovered in future rates. Based on anticipated regulatory actions and current practices, management believes that any costs incurred related to this matter will not have a material effect on the Company s financial condition or results of operations.

MARKET RISK

The Company is exposed to market risks associated with interest rates and commodity prices. Interest rate risk is related to the Company s outstanding long-term and short-term debt. Commodity price risk is experienced by the Company s regulated natural gas operations. The Company s risk management policy, as authorized by the Company s Board of Directors, allows management to enter into both physical and financial transactions for the purpose of managing commodity and interest rate risks of its business operations. The policy also specifies that the combination of all commodity hedging contracts for any 12-month period shall not exceed a total hedged volume of 90% of projected volumes. Finally, the policy specifically prohibits the utilization of derivatives for the purposes of speculation.

The Company is exposed to market risk related to changes in interest rates associated with its borrowing activities. As of September 30, 2006, the Company had $6,613,000 outstanding under its lines-of-credit and $2,000,000 outstanding on an intermediate-term variable rate note. Based upon outstanding borrowings at September 30, 2006, a 100 basis point increase in market interest rates applicable to the Company s variable rate debt (excluding those for which the Company has entered into fixed rate swaps) would have resulted in an increase in annual interest expense of approximately $86,000. The Company also has a $15,000,000 intermediate-term variable rate note that is currently being hedged by a fixed rate interest swap. The fair value of the interest rate swap at September 30, 2006 amounted to a $4,559 unrealized loss on marked to market transactions included on the Consolidated Balance Sheet.

The Company manages the price risk associated with purchases of natural gas by using a combination of liquefied natural gas (LNG) storage, storage gas, fixed price contracts, spot market purchases and derivative commodity instruments including futures, price caps, swaps and collars.

As of September 30, 2006, the Company had swap agreements outstanding for the purpose of hedging the price of natural gas during the winter period for 720,000 decatherms. Any cost incurred or benefit received from the derivative or other hedging arrangements would be expected to be recoverable or refunded through the regulated natural gas purchased gas adjustment (PGA) mechanism. Both the SCC and PSC currently allow for full recovery of prudent costs associated with natural gas purchases, and any additional costs or benefits associated with the settlement of the derivative contracts will be passed through to customers when realized.

CAPITALIZATION RATIOS

(in percentages)

Long Term Debt
Common Stock

OTHER RISKS

The Company is exposed to certain risks other than commodity and interest rates. Such other events, situations or conditions have or potentially could have an impact on the future results of operations of the Company. For most of the items described below, the regulated natural gas operations in Virginia and West Virginia have a means to recover increased costs through formal rate application filings, as well as the ability to automatically pass along increases in natural gas cost. However, rate applications are generally filed based upon historical expenses, which generally results in the Company lagging in the recovery of rapidly increasing operating expenses. Moreover, there can be no guarantee that the respective regulatory commissions in Virginia or West Virginia will allow recovery for all such increased costs when rate applications are filed.

Credit and Customer: Gas costs represent a major portion of the total customer bill. Although, gas costs are expected to be below last year s levels, they will likely be above historical prices. The Company has worked diligently at minimizing bad debts and bad debt write offs. However, management anticipates that the increase in natural gas prices could result in an increase in delinquencies as customers face higher natural gas bills as well as other higher energy costs. In addition, the respective regulatory commissions in Virginia and West Virginia have specific notice requirements with which the Company must comply before disconnecting natural gas service for customer nonpayment. The Company has mitigated some of the risk through increased deposit requirements based upon higher energy prices as well as obtained credit insurance coverage on certain of the Company s larger volume industrial customers. Furthermore, the Company s rate structure provides a level of protection against the impact that rising energy prices may have on bad debts. Nevertheless, the Company has no such protection if the percentage of bad debts to revenues increases above recent historical levels.

Terrorism: Since the attacks of September 11, 2001, the potential for new terrorist attacks remain a concern. The Company monitors the national alert level and has a security plan in place to address elevated warning levels. The Company is also using insurance as a means to mitigate the potential financial impact of a terrorist attack.

Stock Market Performance: Although equity investments have largely recovered from the worst of the 2001 and 2002 stock market decline, the poor stock market performance over those years has affected the Company s performance by increasing certain benefit plan expenses. RGC Resources, Inc. offers both a defined benefit pension plan and postretirement medical benefits. The Company funds both of these plans. Prior poor returns on the investments of these plans continued to have a negative impact resulting in increased expense accruals over the last several years. The Company has increased its funding levels for the defined benefit pension plan and has maintained a consistent funding plan for postretirement medical benefits. This funding plan has mitigated the impact of the underfunded position of both plans. Furthermore, the increase in the discount rate (from 5.25% to 6.25%) used to determine the plans obligation valuations has also contributed to the improvement in the underfunded position of the plans as well as reduce the pension and postretirement medical expense for fiscal year 2007.

Corporate Accounting Irregularities: As a consequence of the high-profile irregularities and accounting scandals at a few well-publicized companies, additional regulation and oversight have been legislated by Congress through the Sarbanes-Oxley law to be enforced by the SEC. Although the SEC has delayed the full implementation of Sarbanes-Oxley Section 404 for smaller public companies, the Company has incurred costs to comply with the new requirements. The Company anticipates that it will continue to incur a higher level of cost to complete the implementation and maintain compliance.

Weather: The nature of the Company s business is highly dependent upon weather specifically, winter weather. Cold weather increases energy consumption by customers and therefore increases revenues and margins. Conversely, warm weather reduces energy consumption and ultimately revenues and margins. Since 2003, Roanoke Gas Company s rate structure has included a weather normalization adjustment factor as discussed above. The Company should be at risk for no more than a 6% swing in heating degree-days above or below average.

Capitalization Statistics

Years Ended September 30,	**2006**	**2005**	**2004**	**2003**	**2002**
COMMON STOCK:					
Shares Issued	**2,138,595**	2,098,935	2,065,408	2,003,232	1,960,418
Continuing Operations:					
Basic Earnings Per Share	**$ 1.55**	$ 1.52	$ 0.94	$ 0.92	$ 0.91
Diluted Earnings Per Share	**$ 1.54**	$ 1.51	$ 0.93	$ 0.91	$ 0.91
Discontinued Operations:					
Basic Earnings Per Share	**$ 0.11**	$ 0.17	$ 5.44*	$ 0.86	$ 0.37
Diluted Earnings Per Share	**$ 0.11**	$ 0.17	$ 5.40	$ 0.86	$ 0.37
Dividends Paid Per Share (Cash)	**$ 1.20**	$ 1.18	$ 5.67	$ 1.14	$ 1.14
Dividends Paid Out Ratio	**72.3%**	69.8%	88.9%	64.0%	89.1%
CAPITALIZATION RATIOS:					
Long-Term Debt, Including Current Maturities	**42.6**	44.0	41.5	48.0	48.7
Common Stock And Surplus	**57.4**	56.0	58.5	52.0	51.3
Total	**100.0**	100.0	100.0	100.0	100.0
Long-Term Debt, Including Current Maturities	**$ 30,000,000**	$ 30,000,000	$ 26,019,987	$ 31,252,359	$ 30,482,485
Common Stock And Surplus	**40,494,868**	38,157,357	36,621,522	33,857,614	32,068,997
Total Capitalization Plus Current Maturities	**$ 70,494,868**	$ 68,157,357	$ 62,641,509	$ 65,109,973	$ 62,551,482

* Reflects $4.69 gain on sale of assets.

Market Price & Dividend Price Information

RGC Resources common stock is listed on the Nasdaq National Market under the trading symbol RGCO. Payment of dividends is within the discretion of the Board of Directors and will depend on, among other factors, earnings, capital requirements, and the operating and financial condition of the Company. The Company s long-term indebtedness contains restrictions on dividends based on cumulative net earnings and dividends previously paid.

	Range of Bid Prices		**Cash Dividends**
Fiscal Year Ended September 30,	**High**	**Low**	**Declared**
2006			
First Quarter	27.580	24.500	$ 0.300
Second Quarter	25.740	24.300	0.300
Third Quarter	26.900	22.720	0.300
Fourth Quarter	28.140	24.020	0.300
2005			
First Quarter	26.750	23.060	$ 0.295
Second Quarter	29.550	24.950	0.295
Third Quarter	28.700	24.500	0.295
Fourth Quarter	27.739	25.620	0.295

Summary of Gas Sales & Statistics

Years Ended September 30,	2006	2005	2004	2003	2002
REVENUES:					
Residential Sales	**$ 58,065,543**	$ 54,523,348	$ 47,739,414	$ 42,749,256	$ 33,261,150
Commercial Sales	**42,829,095**	38,782,038	31,899,455	28,371,913	21,723,467
Interruptible Sales	**3,690,899**	3,506,787	1,680,953	2,238,792	771,439
Transportation Gas Sales	**2,115,172**	2,153,279	2,158,411	1,712,960	1,686,141
Backup Services	**3,600**	62,756	51,452	89,590	64,287
Late Payment Charges	**75,681**	59,990	76,142	101,785	100,015
Miscellaneous Gas Utility Revenue	**132,998**	108,389	98,137	57,041	41,448
Other	**884,762**	880,080	621,005	421,479	555,639
Total	**$ 107,797,750**	$ 100,076,667	$ 84,324,969	$ 75,742,816	$ 58,203,586
NET INCOME					
Continuing Operations	**$ 3,274,594**	$ 3,147,640	$ 1,905,388	$ 1,823,218	$ 1,771,705
Discontinued Operations	**236,937**	359,266	11,028,625	1,705,171	715,190
Net Income	**$ 3,511,531**	$ 3,506,906	$ 12,934,013	$ 3,528,389	$ 2,486,895
DTH DELIVERED:					
Residential	**3,971,524**	4,433,020	4,785,309	5,120,975	4,230,055
Commercial	**3,288,393**	3,398,050	3,468,138	3,685,017	3,258,766
Interruptible	**330,901**	372,506	207,939	345,678	156,923
Transportation Gas	**2,892,047**	3,243,281	3,437,004	2,878,796	2,906,988
Backup Service		5,531	5,530	10,727	10,782
Total	**10,482,865**	11,452,388	11,903,920	12,041,193	10,563,514
HEATING DEGREE DAYS	**3,714**	3,783	3,917	4,349	3,502
NUMBER OF CUSTOMER					
Natural Gas					
Residential	**53,619**	53,245	52,413	52,006	51,557
Commercial	**5,643**	5,655	5,623	5,638	5,627
Interruptible and Interruptible					
Transportation Service	**43**	46	45	47	45
Total	**59,305**	58,946	58,081	57,691	57,229
GAS ACCOUNT (DTH):					
Natural Gas Available	**10,702,790**	11,668,310	12,250,411	12,392,866	10,992,271
Natural Gas Deliveries	**10,482,865**	11,452,388	11,903,920	12,041,193	10,563,514
Storage - LNG	**98,936**	89,896	117,378	102,907	112,692
Company Use And Miscellaneous	**36,629**	47,875	52,972	44,450	62,046
System Loss	**84,360**	78,151	176,141	204,316	254,019
Total Gas Available	**10,702,790**	11,668,310	12,250,411	12,392,866	10,992,271
TOTAL ASSETS	**$ 114,662,572**	$ 113,563,416	$ 114,972,556	$ 104,364,733	$ 96,978,115
LONG-TERM OBLIGATIONS	**$ 30,000,000**	$ 30,000,000	$ 26,000,000	$ 30,219,987	$ 30,377,358

Officers and Board of Directors

OFFICERS

John B. Williamson, III

Chairman of the Board, President, and

Chief Executive Officer (1) (2) (3) (4) (5)

J. David Anderson

Assistant Secretary and Assistant

Treasurer (1) (2) (3) (4) (5)

John S. D Orazio

Vice President and

Chief Operating Officer (2) (3) (4)

Howard T. Lyon

Vice President, Treasurer and

Controller (1) (2) (3) (4) (5)

Dale P. Lee

Vice President and Secretary (1) (2) (3) (4) (5)

Jane N. O Keeffe

Vice President, Human Resources (1)

C. James Shockley, Jr.

Vice President, Operations (5)

Robert L. Wells

Vice President,

Information Technology (1) (3) (4)

DIRECTORS

Nancy H. Agee

Chief Operating Officer/

Executive Vice President

Carilion Health System

Director: [1] [2]

Abney S. Boxley, III

President, and Chief Executive Officer

Boxley Materials Company

Director: [1] [2]

Frank T. Ellett

President

Virginia Truck Center, Inc.

Director: [1] [2]

Maryellen F. Goodlatte

Attorney and Principal

Glenn Feldmann Darby & Goodlatte

Director: [1] [2]

J. Allen Layman

Private Investor

Director: [1] [2]

George W. Logan

Chairman of the Board

Valley Financial Corporation

Principal

Pine Street Partners

Faculty

University of Virginia

Darden Graduate School of Business

Director: [1]

S. Frank Smith

Manager - Sales

Alpha Coal Sales Company, LLC

Director: (1) (2)

Raymond D. Smoot, Jr.

Chief Operating Officer and

Secretary-Treasurer

Virginia Tech Foundation, Inc.

Director: (1)

John B. Williamson, III

Chairman of the Board, President, and

Chief Executive Officer

Director: (1) (2) (3) (4) (5)

SUBSIDIARY BOARDS OF DIRECTORS:

John S. D Orazio

Vice President and

Chief Operating Officer

Roanoke Gas Company

Director: (3) (4) (5)

Howard T. Lyon

Vice President, Treasurer and Controller

RGC Resources, Inc.

Director: (3) (4) (5)

Dale P. Lee

Vice President and Secretary

RGC Resources, Inc.

Director: (3) (4) (5)

C. James Shockley, Jr.

Vice President, Operations

Bluefield Gas Company

Director: [5]

Robert L. Wells

Vice President, Information Technology

RGC Resources, Inc.

Director: [3] [4]

[1] *RGC Resources, Inc.*

[2] *Roanoke Gas Company*

[3] *Diversified Energy Company*

[4] *RGC Ventures of Virginia, Inc.*

[5] *Bluefield Gas Company*

Corporate Information

CORPORATE OFFICE

RGC RESOURCES, INC.

519 Kimball Avenue, N.E.

P.O. Box 13007

Roanoke, VA 24030

(540) 777-4GAS (4427)

Fax (540) 777-2636

AUDITORS

BROWN EDWARDS & COMPANY, L.L.P.

319 McClanahan Street, S.W.

Roanoke, VA 24014

COMMON STOCK TRANSFER AGENT, REGISTRAR, DIVIDEND DISBURSING

AMERICAN STOCK TRANSFER & TRUST COMPANY

59 Maiden Lane

New York, NY 10038

COMMON STOCK

RGC Resources common stock is listed on the Nasdaq National Market under the trading symbol RGCO.

DIRECT DEPOSIT OF DIVIDENDS AND SAFEKEEPING OF STOCK CERTIFICATES

Shareholders can have their cash dividends deposited automatically into checking, saving or money market accounts. The shareholder s financial institution must be a member of the Automated Clearing House. Also, RGC Resources offers safekeeping of stock certificates for shares enrolled in the dividend reinvestment plan. For more information about these shareholder services, please contact the Transfer Agent, American Stock Transfer & Trust Company.

10-K REPORT

A copy of RGC Resources, Inc. latest annual report to the Securities & Exchange Commission on Form 10-K will be provided without charge upon written request to:

DALE P. LEE

Vice President and Secretary

RGC Resources, Inc.

P.O. Box 13007

Roanoke, VA 24030

(540) 777-3846

Access all RGC Resources Inc. s Securities and Exchange filings through the links provided on our website at: www.rgcresources.com.

SHAREHOLDER INQUIRIES

Questions concerning shareholder accounts, stock transfer requirements, consolidation of accounts, lost stock certificates, safekeeping of stock certificates, replacement of lost dividend checks, payment of dividends, direct deposit of dividends, initial cash payments, optional cash payments and name or address changes should be directed to the Transfer Agent, American Stock Transfer & Trust Company. All other shareholder questions should be directed to:

RGC RESOURCES, INC.

Vice President and Secretary

P.O. Box 13007

Roanoke, VA 24030

(540) 777-3846

FINANCIAL INQUIRIES

All financial analysts and professional investment managers should direct their questions and requests for financial information to:

RGC RESOURCES, INC.

Vice President and Secretary

P.O. Box 13007

Roanoke, VA 24030

(540) 777-3846

Access up-to-date information on RGC Resources and its subsidiaries at www.rgcresources.com.

519 Kimball Avenue, N.E.

P.O. Box 13007

Roanoke, VA 24030

www.rgcresources.com

Trading on NASDAQ as RGCO

RGC Resources, Inc.

and Subsidiaries

Consolidated Financial Statements

for the Years Ended September 30, 2006, 2005,

and 2004, and Report of Independent

Registered Public Accounting Firm

RGC RESOURCES, INC. AND SUBSIDIARIES

TABLE OF CONTENTS

BROWN,

EDWARDS &

COMPANY, L.L.P.

Certified Public Accountants

Board of Directors and Stockholders

RGC Resources, Inc.

Roanoke, Virginia

We have audited the accompanying consolidated balance sheet of RGC Resources, Inc. and Subsidiaries as of September 30, 2006, and the related consolidated statements of income and comprehensive income, stockholders equity, and cash flows for the year ended September 30, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. The financial statements of RGC Resources, Inc. and Subsidiaries as of September 30, 2005, and for the two years ended September 30, 2005, before the adjustment to reflect the operations of the energy marketing division as discontinued operations as described in Note 2, were audited by other auditors whose report, dated December 15, 2005, expressed an unqualified opinion on those statements.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of RGC Resources, Inc. and Subsidiaries as of September 30, 2006, and the consolidated results of their operations and cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.

On July 10, 2006, the Company sold certain of its assets related to the energy marketing business. We have audited the adjustments to the 2005 and 2004 financial statements to retroactively reflect the energy marketing business as Discontinue Operations as more fully described in Note 2. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review, or apply any procedures to the 2005 and 2004 financial statements of the Company other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2005 and 2004 financial statements taken as a whole.

/s/ Brown, Edwards & Company, L.L.P.
CERTIFIED PUBLIC ACCOUNTANTS

319 McClanahan Street, S.W.

Roanoke, Virginia

November 15, 2006

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2006 AND 2005

	2006	2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,490,141	$ 1,349,518
Accounts receivable, less allowance for doubtful accounts of $34,980 in 2006 and $284,008 in 2005	5,217,009	7,441,761
Materials and supplies	649,578	701,100
Gas in storage	23,331,703	23,464,537
Prepaid income taxes	928,820	883,617
Deferred income taxes	2,436,516	2,533,770
Under-recovery of gas costs	611,435	2,248,410
Fair value of marked-to-market transactions		13,606
Other	474,355	412,236
Total current assets	35,139,557	39,048,555
UTILITY PROPERTY:		
In service	114,958,652	107,663,713
Accumulated depreciation and amortization	(37,777,044)	(35,341,798)
In service net	77,181,608	72,321,915
Construction work in progress	1,855,743	1,774,804
Utility plant net	79,037,351	74,096,719
NONUTILITY PROPERTY:		
Nonutility property	22,762	22,762
Accumulated depreciation and amortization	(20,504)	(17,116)
Nonutility property net	2,258	5,646
Other assets	483,406	412,496
TOTAL ASSETS	$ 114,662,572	$ 113,563,416

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2006 AND 2005

	2006	2005
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Borrowings under lines of credit	$ 6,613,000	$ 7,662,000
Dividends payable	643,067	619,532
Accounts payable	9,451,343	16,277,773
Customer credit balances	4,403,833	2,853,645
Customer deposits	1,293,019	991,864
Accrued expenses	3,699,083	4,305,766
Refunds from suppliers due customers	2,447	4,954
Over-recovery of gas costs	2,112,256	
Fair value of marked-to-market transactions	1,621,439	
Total current liabilities	29,839,487	32,715,534
LONG-TERM DEBT	30,000,000	30,000,000
DEFERRED CREDITS AND OTHER LIABILITIES:		
Asset retirement obligations	2,682,138	
Regulatory cost of retirement obligations	5,547,642	6,967,622
Deferred income taxes	5,933,626	5,524,841
Deferred investment tax credits	164,811	198,062
Total deferred credits and other liabilities	14,328,217	12,690,525
COMMITMENTS AND CONTINGENCIES (Notes 11 and 12)		
CAPITALIZATION:		
Stockholders equity:		
Common stock, $5 par value; authorized 10,000,000 shares; issued and outstanding 2,138,595 and 2,098,935 shares in 2006 and 2005, respectively	$ 10,692,975	$ 10,494,675
Preferred stock, no par; authorized 5,000,000 shares; no shares issued or outstanding in 2006 and 2005		
Capital in excess of par value	14,521,812	13,720,348
Retained earnings	15,282,909	14,322,805
Accumulated other comprehensive loss	(2,828)	(380,471)
Total stockholders equity	40,494,868	38,157,357
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 114,662,572	$ 113,563,416

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2006, 2005, AND 2004

	2006	2005	2004
OPERATING REVENUES:			
Gas utilities	$ 106,912,988	$ 99,196,587	$ 83,703,964
Other	884,762	880,080	621,005
Total operating revenues	107,797,750	100,076,667	84,324,969
COST OF SALES:			
Gas utilities	81,200,577	74,932,893	60,870,458
Other	531,730	382,953	328,133
Total cost of sales	81,732,307	75,315,846	61,198,591
GROSS MARGIN	26,065,443	24,760,821	23,126,378
OTHER OPERATING EXPENSES:			
Operations	10,958,133	10,573,706	11,068,530
Maintenance	1,475,584	1,501,213	1,741,853
General taxes	1,679,288	1,530,702	1,495,130
Depreciation and amortization	4,246,577	4,029,117	3,891,141
Total other operating expenses	18,359,582	17,634,738	18,196,654
OPERATING INCOME	7,705,861	7,126,083	4,929,724
OTHER EXPENSES Net	12,682	60,418	19,621
INTEREST EXPENSE	2,478,626	2,025,293	1,883,736
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	5,214,553	5,040,372	3,026,367
INCOME TAX EXPENSE FROM CONTINUING OPERATIONS	1,939,959	1,892,732	1,120,979
INCOME FROM CONTINUING OPERATIONS	3,274,594	3,147,640	1,905,388
DISCONTINUED OPERATIONS:			
Income from discontinued operations net of income taxes of $145,014, $220,595 and $7,321,664 in 2006, 2005, and 2004, respectively	236,937	359,266	11,028,625
NET INCOME	3,511,531	3,506,906	12,934,013
OTHER COMPREHENSIVE INCOME (LOSS) NET OF TAX	377,643	(334,961)	109,040
COMPREHENSIVE INCOME	$ 3,889,174	$ 3,171,945	$ 13,043,053

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2006, 2005, AND 2004

	2006	2005	2004
BASIC EARNINGS PER COMMON SHARE:			
Income from continuing operations	$ 1.55	$ 1.52	$ 0.94
Discontinued operations	0.11	0.17	5.44
Net income	1.66	1.69	6.38
DILUTED EARNINGS PER COMMON SHARE:			
Income from continuing operations	$ 1.54	$ 1.51	$ 0.93
Discontinued operations	0.11	0.17	5.40
Net income	$ 1.65	$ 1.68	$ 6.33
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	2,120,267	2,079,851	2,027,908
Diluted	2,130,720	2,093,115	2,042,312

(Concluded)

See notes to consolidated financial statements.

- 5 -

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

YEARS ENDED SEPTEMBER 30, 2006, 2005 AND 2004

	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
BALANCE September 30, 2003	$ 10,016,160	$ 11,977,084	$ 12,018,920	$ (154,550)	$ 33,857,614
Net income			12,934,013		12,934,013
Gain on hedging activities net of tax				109,040	109,040
Cash dividends declared ($5.67 per share)			(11,677,507)		(11,677,507)
Issuance of common stock (62,176 shares)	310,880	1,087,482			1,398,362
BALANCE September 30, 2004	10,327,040	13,064,566	13,275,426	(45,510)	36,621,522
Net income			3,506,906		3,506,906
Gain on hedging activities net of tax				53,951	53,951
Minimum pension liability net of tax				(388,912)	(388,912)
Cash dividends declared ($1.18 per share)			(2,459,527)		(2,459,527)
Issuance of common stock (33,527 shares)	167,635	655,782			823,417
BALANCE September 30, 2005	10,494,675	13,720,348	14,322,805	(380,471)	38,157,357
Net income			3,511,531		3,511,531
Loss on hedging activities net of tax				(11,269)	(11,269)
Minimum pension liability net of tax				388,912	388,912
Cash dividends declared ($1.20 per share)			(2,551,427)		(2,551,427)
Issuance of common stock (39,660 shares)	198,300	801,464			999,764
BALANCE September 30, 2006	$ 10,692,975	$ 14,521,812	$ 15,282,909	$ (2,828)	$ 40,494,868

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2006, 2005 AND 2004

	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income from continuing operations	$ 3,274,594	$ 3,147,640	$ 1,905,388
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	4,480,711	4,280,027	4,128,980
Cost of removal of utility plant net	(291,877)	(279,620)	(229,670)
Loss on disposal of property		33,590	
Gain on sale of short-term investments		(8,540)	
Change in over/under recovery of gas costs	5,366,111	(3,842,557)	1,141,538
Deferred taxes and investment tax credits	241,318	(194,261)	(596,789)
Other noncash items net	(70,910)	144,013	213,245
Changes in assets and liabilities which provided (used) cash:			
Accounts receivable and customer deposits net	2,525,907	(1,184,724)	(500,591)
Inventories, gas in storage and prepaid gas	184,356	(5,772,211)	(1,364,866)
Other current assets	(107,322)	1,289,474	(964,203)
Accounts payable, customer credit balances and accured expenses	(5,307,642)	7,712,283	1,009,618
Refunds from suppliers due customers	(2,507)	(17,338)	(20,028)
Total adjustments	7,018,145	2,160,136	2,817,234
Net cash provided by continuing operating activities	10,292,739	5,307,776	4,722,622
Net cash provided by (used in) discontinued operations	3,721	206,119	(2,596,527)
Net cash provided by operating activities	10,296,460	5,513,895	2,126,095
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant and nonutility property	(7,815,341)	(7,427,304)	(7,925,948)
Proceeds from disposal of utility and nonutility property	3,416	90,557	31,345
Purchase of short-term investments			(4,991,460)
Proceeds from sale of short-term investments		5,000,000	
Net cash used in continuing investing activities	(7,811,925)	(2,336,747)	(12,886,063)
Net cash provided by investing activities of discontinued operations	233,216	731,711	26,514,169
Net cash (used in) provided by investing activities	(7,578,709)	(1,605,036)	13,628,106
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of long-term debt	17,000,000		2,000,000
Retirement of long-term debt and capital leases	(13,000,000)	(19,987)	(6,357,372)
Net repayments under line-of-credit agreements	(5,049,000)	(1,080,000)	(1,125,000)
Proceeds from issuance of common stock	999,764	823,417	1,398,362
Cash dividends paid	(2,527,892)	(11,743,988)	(2,344,972)
Net cash used in financing activities	(2,577,128)	(12,020,558)	(6,428,982)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	140,623	(8,111,699)	9,325,219
CASH AND CASH EQUIVALENTS Beginning of year	1,349,518	9,461,217	135,998

CASH AND CASH EQUIVALENTS End of year	$ 1,490,141	$ 1,349,518	$ 9,461,217

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2006, 2005 AND 2004

	2006	**2005**	**2004**
SUPPLEMENTAL DISCLOSURE OF CASH FLOWS INFORMATION:			
Cash paid during the year for:			
Interest	$ 2,377,906	$ 2,131,430	$ 2,076,895
Income taxes net of refunds	$ 1,888,858	$ 912,844	$ 10,237,991

Non-cash transactions:

In 2006, 2005 and 2004, the Company entered into derivative price swaps and price cap arrangements for the purpose of hedging the cost of gas and interest rate swaps to hedge interest expense. In accordance with hedge accounting requirements, the underlying derivatives were marked to market with the corresponding non-cash impacts to the consolidated balance sheets:

Unrealized gain (loss) on marked-to-market transactions	$ (1,635,045)	$ 86,962	$ 245,908
Under (over) recovery of gas costs	1,616,880		(70,150)
Deferred tax asset (liability)	6,896	(33,011)	(66,718)

Subsequent to September 30, 2005, the Company executed a $15,000,000 five-year intermediate note with provision for annual renewals for five years thereafter for Roanoke Gas Company and a $2,000,000 31-month note for Bluefield Gas Company to refinance currently maturing debt, a portion of the line of credit balances and long-term debt. A $10,000,000 reclassification from current maturities of long-term debt and a $4,000,000 reclassification from borrowings under lines-of-credit were made to long-term debt at September 30, 2005. The refinancing activities are reflected in the September 30, 2006 cash flow statement.

In 2005, the Company recorded a minimum pension liability associated with its defined pension plan. In 2006, the minimum pension liability reversed. These transactions had the following non-cash impact in the balance sheet:

Deferred tax liability	$ 238,366	$ (238,366)
Accrued Expenses	(627,278)	627,278

In September 2006, the Company adopted FASB Interpretation No. 47 (as discussed in Note 14) which resulted in the reclassification of a regulatory liability to a legal liability and established an asset net of accumulated depreciation. The non-cash impact to the balance sheet is reflected below:

Utility Plant-net	$ 454,678
Asset retirement obligation	(2,682,138)
Regulatory cost of retirement	2,227,460

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED SEPTEMBER 30, 2006, 2005, AND 2004

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General RGC Resources, Inc. is an energy services company engaged in the sale and distribution of natural gas. The consolidated financial statements include the accounts of RGC Resources, Inc. and its wholly owned subsidiaries (Resources or the Company); Roanoke Gas Company; Bluefield Gas Company; Diversified Energy Company, operating as Highland Energy; and RGC Ventures, Inc. of Virginia, operating as Application Resources. Roanoke Gas Company and Bluefield Gas Company are natural gas utilities, which distribute and sell natural gas to residential, commercial and industrial customers within their service areas. Highland Energy brokered natural gas to several industrial transportation customers of Roanoke Gas Company and Bluefield Gas Company. Application Resources provides information system services to software providers in the utility industry.

The primary business of the Company is the distribution of natural gas to residential, commercial and industrial customers in Roanoke, Virginia; Bluefield, Virginia; Bluefield, West Virginia; and the surrounding areas. The Company distributes natural gas to its customers at rates regulated by the State Corporation Commission in Virginia (SCC or Virginia Commission) and the Public Service Commission in West Virginia (PSC or West Virginia Commission).

The Company s business is seasonal in nature and weather dependent as a majority of natural gas sales are for space heating during the winter season. As the rates for which the Company charges its customers for natural gas are set by the respective Commissions based on a 30 year normal, winter weather that is warmer than the 30 year normal will negatively impact sales. Furthermore, volatility in the commodity price of natural gas may result in customer conservation or customers switching to an alternative fuel.

On July 10, 2006, Diversified Energy Company entered into an asset purchase and sale agreement for the sale of its energy marketing operations. These operations as such are classified as discontinued operations. In addition to an energy marketing company, Diversified Energy Company operated an unregulated propane operation under the name of Highland Propane Company. In July 2004, Resources sold the propane operations. Please see Note 2 below for further discussions on the sale of certain assets of Highland Energy and Highland Propane Company.

All intercompany transactions have been eliminated in consolidation.

Rate Regulated Basis of Accounting The Company s regulated operations follow the accounting and reporting requirements of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. The economic effects of regulation can result in a regulated company deferring costs that have been or are expected to be recovered from customers in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this results, costs are deferred as assets in the consolidated balance sheet (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future (regulatory liabilities).

Regulatory assets and liabilities included in the Company s consolidated balance sheets as of September 30, 2006 and 2005 are as follows:

	September 30	
	2006	**2005**
Regulatory assets:		
Under-recovery of gas costs	$ 611,435	$ 2,248,410
Bad debt expense deferral		17,609
Line break expense deferral	123,534	158,805
Premium on early retirement of debt	278,454	
Asset retirement costs	726,284	
Other	35,909	58,641
Total regulatory assets	$ 1,775,616	$ 2,483,465
Regulatory liabilities:		
Regulatory cost of retirement obligation	$ 5,547,642	$ 6,967,622
Over-recovery of gas costs	2,112,256	
Refunds from suppliers due customers	2,447	4,954
Total regulatory liabilities	$ 7,662,345	$ 6,972,576

Utility Plant and Depreciation Utility plant is stated at original cost. The cost of additions to utility plant includes direct charges and overhead. The cost of depreciable property retired is charged to accumulated depreciation. The cost of asset removals, less salvage, is charged to regulatory cost of retirement obligations or asset retirement obligations as explained in Note 14. Maintenance, repairs, and minor renewals and betterments of property are charged to operations and maintenance.

Provisions for depreciation are computed principally at composite straight-line rates with annual composite rates ranging up to 17% for utility property. Depreciable lives for non-utility property range from 3 to 40 years. The annual composite rates for utility property are determined by periodic depreciation studies that are approved by the respective regulatory commissions. The Virginia Commission requires Roanoke Gas Company to conduct a depreciation study every five years and propose new depreciation rates for approval. The results of Roanoke Gas Company s last depreciation study were placed into effect January 1, 2004.

The composite rates are comprised of two components, one based on average service life and one based on cost of retirement. Therefore, the Company accrues estimated cost of retirement of long-lived assets through depreciation expense. Retirement costs are not a legal obligation as defined by SFAS No. 143 but rather the result of cost-based regulation and accounted for under the provisions of SFAS No. 71. Therefore, such amounts are classified as a regulatory liability. See Footnote 14 regarding legal obligations related to asset retirements.

The Company reviews long-lived assets and certain identifiable intangibles for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Our reviews have not identified a material effect on results of operations or financial condition.

Cash, Cash Equivalents and Short-Term Investments For purposes of the consolidated statements of cash flows, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Inventories Inventories consist of natural gas in storage and materials and supplies. Inventories are recorded at average cost.

Unbilled Revenues The Company bills its natural gas customers on a monthly cycle basis; however, the billing cycle period for most customers does not coincide with the accounting periods used for financial reporting and, therefore, accrues estimates for natural gas delivered to customers not yet billed during the accounting period. The Company recognizes revenue when gas is delivered. The amounts of unbilled revenue receivable included in accounts receivable on the consolidated balance sheets at September 30, 2006 and 2005 were $1,565,727 and $1,736,976, respectively.

Income Taxes Income taxes are accounted for using the asset and liability method. Under the asset and liability method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the years in which those temporary differences are expected to be recovered or settled. A valuation allowance against deferred tax assets is provided if it is more likely than not the deferred tax asset will not be realized. The Company and its subsidiaries file a consolidated federal income tax return.

Debt Expenses Debt issuance expenses are being amortized over the lives of the debt instruments.

Over/Under Recovery of Natural Gas Costs Pursuant to the provisions of the Company s Purchased Gas Adjustment (PGA) clause, increases or decreases in natural gas costs incurred by regulated operations, including gains and losses on derivative hedging instruments, are passed through to customers. Accordingly, the difference between actual costs incurred and costs recovered through the application of the PGA is reflected as a regulatory asset or liability. At the end of the deferral period, the balance of the net deferred charge or credit is amortized over an ensuing 12-month period as amounts are reflected in customer billings. The Company is subject to multiple jurisdictions, which may result in both a regulatory asset and a regulatory liability reported in the financial statements.

Use of Estimates The preparation of financial statements in conformity with Generally Accepted Accounting Principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent 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.

Reclassifications Certain prior period amounts have been reclassified to conform to current year presentation. Specifically, the Company reclassified certain financial statement items for 2005 and 2004 to reflect the effect of discontinued operations discussed in Note 2. The Company reclassified credit balances on customer accounts from accounts payable into customer credit balances under current liabilities. The Company also renamed its non legal obligations for retirement of assets to regulatory cost of retirement obligations and established its legal obligations under FIN 47 as asset retirement obligations . See note 14 for more information on the asset retirement obligations.

Earnings Per Share Basic earnings per share and diluted earnings per share are calculated by dividing net income by the weighted average common shares outstanding during the period and the weighted average common shares outstanding during the period plus dilutive potential common shares, respectively. Dilutive potential common shares are calculated in accordance with the treasury stock method, which assumes that proceeds from the exercise of all options are used to repurchase common stock at market value. The amount of shares remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities. A reconciliation of the weighted average common shares to diluted average common shares is provided below:

	Year Ended September 30		
	2006	**2005**	**2004**
Weighted average common shares	2,120,267	2,079,851	2,027,908
Effect of dilutive securities:			
Options to purchase common stock	10,453	13,264	14,404
Diluted average common shares	2,130,720	2,093,115	2,042,312

Business and Credit Concentrations The primary business of the Company is the distribution of natural gas to residential, commercial and industrial customers in its service territories. The level of natural gas requirements by certain industrial customers may result in a level of concentration above 5% of total sales or total accounts receivable for the periods reported.

No regulated sales to individual customers accounted for more than 5% of total revenue. Including discontinued operations, one customer accounted for 5.8%, 5.3% and 5.5% of total sales. This same customer accounted for 8.6% of the Company s total accounts receivable at September 30, 2005.

Both Roanoke and Bluefield Gas Companies are served by multiple natural gas transmission pipelines; however, by the stage of physical interconnection with each company s distribution facilities the transmission of natural gas has consolidated into two primary pipelines. Depending upon weather conditions and the level of customer demand, failure of one or more of these transmission pipelines could have a major adverse impact on the Company.

Derivative and Hedging Activities SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted, requires the recognition of all derivative instruments as assets or liabilities in the Company s balance sheet and measurement of those instruments at fair value.

The Company s risk management policy allows management to enter into derivatives for the purpose of managing commodity and financial market risks of its business operations. The Company s risk management policy specifically prohibits the use of derivatives for speculative purposes. The key market risks that RGC Resources, Inc. hedges against include the price of natural gas and the cost of borrowed funds.

Prior to the sale of the propane operations, the Company had entered into futures, swaps and caps for the purpose of hedging the price of propane in order to provide price stability during the winter months. During the fiscal year ended September 30, 2004, the Company realized gains on derivative swap arrangements of $99,747. The hedges qualified as cash flow hedges; therefore, changes in the fair value are reported in other comprehensive income.

In addition, the Company entered into futures, swaps and caps for the purpose of hedging the price of natural gas in order to provide price stability during the winter months. The fair value of these instruments is recorded in the balance sheet with the offsetting entry to either under-recovery of gas costs or over-recovery of gas costs. Net income and other comprehensive income are not affected by the change in market value as any cost incurred or benefit received from these instruments is recoverable or refunded through the PGA. Both the Virginia Commission and the West Virginia Commission allow for full recovery of prudent costs associated with natural gas purchases, and any additional costs or benefits associated with the settlement of these instruments will be passed through to customers when realized. At September 30, 2006, the Company has swap agreements outstanding for the winter period to hedge 720,000 decatherms of natural gas.

The Company also entered into an interest rate swap related to the $15,000,000 note issued in November 2005. The swap essentially converted the floating rate note based on LIBOR into fixed rate debt with a 5.74% interest rate. The swap qualifies as a cash flow hedge with changes in fair value reported in other comprehensive income.

No derivative instruments were deemed to be ineffective for any period as defined under SFAS No. 133.

Other Comprehensive Income A summary of other comprehensive income and financial instrument activity is provided below:

Year Ended Septem ber 30, 2006	Natural Gas Derivatives	Interest Rate Swap	Minim um Pension Liability	Total
Unrealized gains (losses)	$	$ (29,000)	$ 627,278	$ 598,278
Income tax (expense) benefit		11,008	(238,366)	(227,358)
Net unrealized gains (losses)		(17,992)	388,912	370,920
Transfer of realized losses to income		10,835		10,835
Income tax benefit		(4,112)		(4,112)
Net transfer of realized losses to income		6,723		6,723
Net other comprehensive income (loss)	$	$ (11,269)	$ 388,912	$ 377,643
Fair value of marked to market transactions	$ (1,616,880)	$ (4,559)	$	$ (1,621,439)
Accumulated comprehensive loss	$	$ (2,828)	$	$ (2,828)

Year Ended September 30, 2005	Propane Derivatives	Interest Rate Swap	Minim um Pension Liability	Total
Unrealized gains (losses)	$	$ 54,634	$ (627,278)	$ (572,644)
Income tax (expense) benefit		(20,739)	238,366	217,627
Net unrealized gains (losses)		33,895	(388,912)	(355,017)
Transfer of realized losses to income		32,328		32,328
Income tax benefit		(12,272)		(12,272)
Net transfer of realized losses to income		20,056		20,056
Net other comprehensive income (loss)	$	$ 53,951	$ (388,912)	$ (334,961)
Fair value of marked to market transactions	$	$ 13,606	$	$ 13,606
Accumulated comprehensive income (loss)	$	$ 8,441	$ (388,912)	$ (380,471)

Year Ended September 30, 2004	Propane Derivatives	Interest Rate Swap	Minim um Pension Liability	Total
Unrealized gains	$ 99,747	$ 16,292	$	$ 116,039
Income tax expense	(38,852)	(6,185)		(45,037)
Net unrealized gains	60,895	10,107		71,002
Transfer of realized (gains) losses to income	(99,747)	159,466		59,719
Income tax expense (benefit)	38,852	(60,533)		(21,681)
Net transfer of realized (gains) losses to income	(60,895)	98,933		38,038
Net other comprehensive income	$	$ 109,040	$	$ 109,040

Stock-Based Compensation On October 1, 2005, the Company adopted SFAS No. 123R, *Share-Based Payment,* a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*. This statement eliminates the alternative to use the intrinsic value method of accounting as prescribed under Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees*. Under APB Opinion No. 25, the Company did not recognize stock-based employee compensation expense related to its Key Employees Stock Option Plan (Plan) in net income as all options granted under the Plan had an exercise price equal to the market value of the underlying common stock on the date of the grant. SFAS No. 123R requires entities to recognize the cost of employee services received in exchange for awards of equity instruments using a fair-value-based method on the grant-date. The Company has adopted the provisions of this statement using the modified prospective application. Under the modified prospective application, only new grants and grants that have been modified, cancelled or have not yet vested as of the effective date of the statement require recognition of compensation cost. All awards granted and vested prior to the effective date remain under the provisions of APB Opinion No. 25. No options were granted in fiscal 2006, 2005 and 2004 and all outstanding options were fully vested at October 1, 2005.

New Accounting Standards In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109*. This statement clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. This Interpretation prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The recognition threshold is based upon whether it is more-likely-than-not that a tax position taken by an enterprise will be sustained upon examination. The measurement attribute of a more-likely-than-not tax position is measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. The effective date of this statement is for fiscal years beginning after December 15, 2006. The Company has not completed its evaluation of this statement but does not anticipate the adoption to have a material impact on the Company s financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value methods. This statement does not require any new fair value measurements. Instead, it provides for increased consistency and comparability in fair value measurements and for expanded disclosure surrounding the fair value measurements. This statement is effective for fiscal years beginning after November 15, 2007.

In September 2006, the FASB issued SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132R.* This statement requires employers who sponsor one or more single-employer defined benefit plans to recognize the overfunded or underfunded position of such plan(s) as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement also requires the measurement of the defined benefit plan assets and obligations as of the date of the employer s balance sheet date and additional disclosures in the financial statement footnotes. The effective date of this statement is for fiscal years ending after December 15, 2006. The requirement to measure plan assets and benefit obligations as of the fiscal year end balance sheet date is effective for fiscal years ending after December 15, 2008. The Company has not completed its evaluation of this statement and has not yet determined the full impact on the Company s financial position or results of operations in light of the current regulatory environment and the application of SFAS No. 71. In the absence of the considerations of SFAS No. 71 and using the most current valuation information as reflected in Note 7, the adoption of this statement as of September 30, 2006 would have resulted in the following adjustments to the consolidated balance sheet:

	As Currently Presented	Adjustment	After Application of Statement 158
Accrued expenses	$ 3,699,083	$ 4,255,560	$ 7,954,643
Deferred income taxes	5,933,626	(1,656,588)	4,277,038
Accumulated other comprehensive loss	(2,828)	(2,638,447)	(2,641,275)

Furthermore, the Company does not expect the adoption of this statement to adversely affect the results of operations or cash flows on a going forward basis.

2. DISCONTINUED OPERATIONS

On July 10, 2006, Diversified Energy Company d/b/a Highland Energy, a wholly owned subsidiary of RGC Resources, Inc. entered into an asset purchase and sale agreement for the sale of the assets relating to its energy marketing business to Atmos Energy Marketing, LLC (Atmos). The assets sold included the gas supply contracts between Highland Energy and its customers and related business records. The date of transfer was set as the date from the first meter read performed for each of the end user customers on or after August 1, 2006.

The Board of Directors approved management s plan to sell the assets and operations of Highland Energy for several reasons. Competition from other energy marketing companies was putting increasing downward pressure on the already low margins associated with the gas marketing business. Significantly rising energy prices over the last few years had increased concern over customers credit risks while increasing the sales margin to compensate for the increased credit risks was not realistic in a strongly competitive market. Management concluded that the developing risk-return relationship of the energy marketing operations warranted monetizing the remaining value of existing customer service contracts and discontinuing unregulated energy marketing operations.

The purchase price for the assets sold by Highland Energy is valued at up to $414,270. Atmos paid Highland Energy the sum of $233,216 at closing, which was recognized as a gain in 2006. The remaining $181,054 will be paid by Atmos to Highland Energy in August 2007 provided that the remaining balance to be paid will be adjusted downward on a customer by customer basis by a prescribed amount to the extent (i) the customer pursuant to an assigned contract is no longer a customer on the anniversary date and such customer was not a customer for two of the preceding twelve months, or (ii) the customer reduces their average natural gas consumption by more than 20 percent from current annualized levels.

As a result of the sale of the assets of Highland Energy, the Company recognized a loss of approximately $147,000 in discontinued operations related to basis intended for future gas deliveries to Highland Energy customers. Basis is defined as the transportation cost component of the gas purchase agreements necessary for pipeline utilization to transport customer gas purchases from supplier to the distribution company s pipeline.

On July 12, 2004, Resources sold the propane assets of its subsidiary, Diversified Energy Company, d/b/a Highland Propane Company (Diversified), for approximately $28,500,000 in cash to Inergy Propane, LLC (Inergy). The sale of assets encompassed all propane plant assets (with the exception of a limited number of specific assets retained by Diversified), the name Highland Propane, customer accounts receivable, propane gas inventory and inventory of propane related materials. The Company realized a gain of approximately $9,500,000 on the sale of assets, net of income taxes.

Concurrent with the sale of assets, the Company entered into an agreement with Inergy by which the Company would continue to provide the use of office, warehouse and storage space, and computer systems and office equipment and the utilization of Company personnel for billing, propane delivery and related services for the term of one year with an option for an additional year. Inergy notified the Company of its intent not to extend the remaining portions of the agreement and to allow the contract to expire in July 2005 with the exception of a lease agreement for access to the storage yard in Bluefield, West Virginia. For the year ended September 30, 2005, the Company realized approximately $451,000 in other revenues and $266,000 in other margin attributable to this agreement.

The asset purchase agreement did not include land and buildings owned by Diversified. Inergy leased 10 parcels of real estate consisting of bulk storage facilities and office space from Diversified with an option to purchase such parcels. Prior to the end of June 2005, Inergy executed the option to purchase the real estate and closed on all 10 parcels. The Company realized a net gain on the sale of real estate of approximately $153,000.

The activities associated with Highland Energy, the former propane real estate and the former propane operations and the corresponding gains from sales of real estate and operations have been classified as Discontinued Operations in accordance with the provisions of SFAS No. 144

Accounting for the Impairment or Disposal of Long-Lived Assets. The discontinued operations related to the sale of Highland Energy contracts in August 2006, the sale of real estate in June 2005 and sale of propane assets in July 2004 is as follows:

		September 30	
	2006	**2005**	**2004**
Discontinued Operations:			
Pretax operating income	$ 148,735	$ 387,348	$ 252,813
Gain on sale of assets	233,216		
Income tax	(145,014)	(147,055)	(98,434)
Income from operations discontinued in 2006	236,937	240,293	154,379
Income from operations discontinued in 2005		118,973	7,035
Income from operations discontinued in 2004			10,867,211
Discontinued operations	$ 236,937	$ 359,266	$ 11,028,625

Total revenues associated with the discontinued operations of Highland Energy were $21,962,564, $21,571,120 and $18,810,525 for 2006, 2005 and 2004, respectively.

With the sale of the operations of Highland Energy and corresponding reclassification of its operations to discontinued operations, Resources has only one reportable segment as defined under SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*. Therefore, the Company is no longer required to separately disclose the information required under this standard.

The following income statements and cash flow statements reflect a reconciliation of the previously reported 2005 and 2004 financial statements to the revised financial statements including the reclassification of the discontinued operations of Highland Energy.

RGC RESOURCES, INC. AND SUBSIDIARIES

RESTATEMENT OF CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME FOR HIGHLAND ENERGY DISCONTINUED OPERATIONS

YEARS ENDED SEPTEMBER 30, 2005 AND 2004

	2005 As Originally Presented	2005 Highland Energy Disc Ops	2005 Restated	2004 As Originally Presented	2004 Highland Energy Disc Ops	2004 Restated
OPERATING REVENUES:						
Gas utilities	$ 99,196,587	$	$ 99,196,587	$ 83,703,964	$	$ 83,703,964
Energy marketing	21,571,120	(21,571,120)		18,810,525	(18,810,525)	
Other	880,080		880,080	621,005		621,005
Total operating revenues	121,647,787	(21,571,120)	100,076,667	103,135,494	(18,810,525)	84,324,969
COST OF SALES:						
Gas utilities	74,932,893		74,932,893	60,870,458		60,870,458
Energy marketing	21,179,939	(21,179,939)		18,555,809	(18,555,809)	
Other	382,953		382,953	328,133		328,133
Total cost of sales	96,495,785	(21,179,939)	75,315,846	79,754,400	(18,555,809)	61,198,591
GROSS MARGIN	25,152,002	(391,181)	24,760,821	23,381,094	(254,716)	23,126,378
OTHER OPERATING EXPENSES:						
Operations	10,577,539	(3,833)	10,573,706	11,070,433	(1,903)	11,068,530
Maintenance	1,501,213		1,501,213	1,741,853		1,741,853
General taxes	1,530,702		1,530,702	1,495,130		1,495,130
Depreciation and amortization	4,029,117		4,029,117	3,891,141		3,891,141
Total other operating expenses	17,638,571	(3,833)	17,634,738	18,198,557	(1,903)	18,196,654
OPERATING INCOME	7,513,431	(387,348)	7,126,083	5,182,537	(252,813)	4,929,724
OTHER EXPENSES Net	60,418		60,418	19,621		19,621
INTEREST EXPENSE	2,025,293		2,025,293	1,883,736		1,883,736
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	5,427,720	(387,348)	5,040,372	3,279,180	(252,813)	3,026,367
INCOME TAX EXPENSE FROM CONTINUING OPERATIONS	2,039,787	(147,055)	1,892,732	1,219,413	(98,434)	1,120,979
INCOME FROM CONTINUING OPERATIONS	3,387,933	(240,293)	3,147,640	2,059,767	(154,379)	1,905,388
DISCONTINUED OPERATIONS - NET OF TAX	118,973	240,293	359,266	10,874,246	154,379	11,028,625
NET INCOME	3,506,906		3,506,906	12,934,013		12,934,013
OTHER COMPREHENSIVE INCOME (LOSS) NET OF TAX	(334,961)		(334,961)	109,040		109,040
COMPREHENSIVE INCOME	$ 3,171,945	$	$ 3,171,945	$ 13,043,053	$	$ 13,043,053

BASIC EARNINGS PER COMMON SHARE:												
Income from continuing operations	$	1.63	$	(0.11)	$	1.52	$	1.02	$	(0.08)	$	0.94
Discontinued Operations		0.06		0.11		0.17		5.36		0.08		5.44
Net income	$	1.69	$		$	1.69	$	6.38	$		$	6.38
DILUTED EARNINGS PER COMMON SHARE:												
Income from continuing operations	$	1.62	$	(0.11)	$	1.51	$	1.01	$	(0.08)	$	0.93
Discontinued Operations		0.06		0.11		0.17		5.32		0.08		5.40
Net income	$	1.68	$		$	1.68	$	6.33	$		$	6.33

RGC RESOURCES, INC. AND SUBSIDIARIES

RESTATEMENT OF CONSOLIDATED STATEMENTS OF CASH FLOWS FOR HIGHLAND ENERGY DISCONTINUED OPERATIONS

YEARS ENDED SEPTEMBER 30, 2005 AND 2004

	2005			2004		
	As Originally Presented	Highland Energy Disc Ops	Restated	As Originally Presented	Highland Energy Disc Ops	Restated
CASH FLOWS FROM OPERATING ACTIVITIES:						
Net income from continuing operations	$ 3,387,933	$ (240,293)	$ 3,147,640	$ 2,059,767	$ (154,379)	$ 1,905,388
Adjustments to reconcile net income to net cash provided by operating activities:						
Depreciation and amortization	4,280,027		4,280,027	4,128,980		4,128,980
Cost of removal of utility plant - net	(279,620)		(279,620)	(229,670)		(229,670)
Loss on disposal of property	33,590		33,590			
Gain on sale of short-term investments	(8,540)		(8,540)			
Change in over/under recovery of gas costs	(3,842,557)		(3,842,557)	1,141,538		1,141,538
Deferred taxes and investment tax credits	(194,261)		(194,261)	(596,789)		(596,789)
Other noncash items - net	144,013		144,013	213,245		213,245
Changes in assets and liabilities which provided (used) cash:						
Accounts receivable and customer deposits - net	(1,184,724)		(1,184,724)	(500,591)		(500,591)
Inventories, gas in storage and prepaid gas	(5,772,211)		(5,772,211)	(1,364,866)		(1,364,866)
Other current assets	1,289,474		1,289,474	(964,203)		(964,203)
Accounts payable and accrued expenses	7,712,283		7,712,283	1,009,618		1,009,618
Refunds from suppliers - due customers	(17,338)		(17,338)	(20,028)		(20,028)
Total adjustments	2,160,136		2,160,136	2,817,234		2,817,234
Net cash provided by continuing operating activities	5,548,069	(240,293)	5,307,776	4,877,001	(154,379)	4,722,622
Net cash provided by (used in) discontinued operations	(34,174)	240,293	206,119	(2,750,906)	154,379	(2,596,527)
Net cash provided by operating activities	5,513,895		5,513,895	2,126,095		2,126,095
CASH FLOWS FROM INVESTING ACTIVITIES:						
Additions to utility plant and nonutility property	(7,427,304)		(7,427,304)	(7,925,948)		(7,925,948)
Proceeds from disposal of utility and nonutility property	90,557		90,557	31,345		31,345
Purchase of short-term investments				(4,991,460)		(4,991,460)

Proceeds from sale of short-term investments	5,000,000		5,000,000			
Net cash used in continuing investing activities	(2,336,747)		(2,336,747)	(12,886,063)		(12,886,063)
Net cash provided by investing activities of discontinued operations	731,711		731,711	26,514,169		26,514,169
Net cash (used in) provided by investing activities	(1,605,036)		(1,605,036)	13,628,106		13,628,106
CASH FLOWS FROM FINANCING ACTIVITIES:						
Proceeds from issuance of long-term debt				2,000,000		2,000,000
Retirement of long-term debt and capital leases	(19,987)		(19,987)	(6,357,372)		(6,357,372)
Net repayments under line-of-credit agreements	(1,080,000)		(1,080,000)	(1,125,000)		(1,125,000)
Proceeds from issuance of common stock	823,417		823,417	1,398,362		1,398,362
Cash dividends paid	(11,743,988)		(11,743,988)	(2,344,972)		(2,344,972)
Net cash used in financing activities	(12,020,558)		(12,020,558)	(6,428,982)		(6,428,982)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(8,111,699)		(8,111,699)	9,325,219		9,325,219
CASH AND CASH EQUIVALENTS - Beginning of year	9,461,217		9,461,217	135,998		135,998
CASH AND CASH EQUIVALENTS - End of year	$ 1,349,518	$	$ 1,349,518	$ 9,461,217	$	$ 9,461,217

3. ALLOWANCE FOR DOUBTFUL ACCOUNTS

A summary of the changes in the allowance for doubtful accounts follows:

	Years Ended September 30		
	2006	**2005**	**2004**
Balances, beginning of year	$ 284,008	$ 38,525	$ 163,900
Provision for doubtful accounts	568,545	685,388	486,949
Recoveries of accounts written off	299,172	340,185	289,179
Transfer to note receivable	(200,000)		
Accounts written off	(916,745)	(780,090)	(901,503)
Balances, end of year	$ 34,980	$ 284,008	$ 38,525

The allowance account at September 30, 2005 included a $200,000 reserve related to a commercial customer that management believed would have difficulty in paying off its obligation. In December 2005, the Company and the customer agreed to convert the receivable balance into a note receivable in the amount of $239,010. The Company transferred the $200,000 in reserve to offset against the note resulting in a net note receivable of $39,010. The note was for 18 months at an interest rate of 6%. As of September 30, 2006, the unpaid balance of the note was $162,268 of which the entire amount has been reserved.

4. BORROWINGS UNDER LINES-OF-CREDIT

The Company has available unsecured lines-of-credit with a bank which will expire March 31, 2007. The Company anticipates being able to extend or replace the lines-of-credit. The Company s available unsecured lines-of-credit vary during the year to accommodate its seasonal borrowing demands. Generally, the Company s borrowing needs are at their lowest in spring, increase during the summer and fall due to gas storage purchases and construction and reach their maximum levels in winter. Available limits under these agreements for the remaining term are as follows:

Effective	**Available Line of Credit**
September 30, 2006	$ 26,000,000
November 16, 2006	31,000,000
February 16, 2007	24,000,000

A summary of the lines-of-credit follows:

	2006	2005	2004
Lines-of-credit at year-end	$ 26,000,000	$ 28,000,000	$ 24,000,000
Outstanding balance at year-end	6,613,000	7,662,000	12,742,000
Highest month-end balances outstanding	24,902,000	18,116,000	20,904,000
Average month-end balances	10,653,000	9,677,000	10,559,000
Average rates of interest during year	5.08%	3.15%	1.79%
Average rates of interest on balances outstanding at year-end	5.94%	4.42%	2.40%

5. LONG-TERM DEBT

Long-term debt consists of the following:

	September 30	
	2006	2005
Roanoke Gas Company:		
First Mortgage notes payable, at 7.804%, due July 1, 2008	$ 5,000,000	$ 5,000,000
Unsecured senior notes payable, at 7.66%, with provision for retirement of $1,600,000 each year beginning December 1, 2014 through December 1, 2018	8,000,000	8,000,000
Unsecured note payable, with variable interest rate based on 30-day LIBOR (5.33% at September 30, 2006) plus 69 basis point spread, with provision for retirement on December 1, 2010	15,000,000	
Collateralized term debentures, at 9.625%		3,000,000
Unsecured note payable, with variable interest rate based on 30-day LIBOR plus 100 basis point spread, with provision for retirement on November 30, 2005		8,000,000
Line-of-credit		4,000,000
Bluefield Gas Company:		
Unsecured note payable with variable interest rate based on 30-day LIBOR (5.33% at September 30, 2006) plus 87 basis point spread, with provision for retirement on July 1, 2008	2,000,000	
Unsecured note payable with variable interest rate based on 30-day LIBOR plus 113 basis point spread, with provision for retirement on November 21, 2005		2,000,000
Total long-term debt	30,000,000	30,000,000
Less current maturities		
Total long-term debt excluding current maturities	$ 30,000,000	$ 30,000,000

The above debt obligations contain various provisions, including a minimum interest charge coverage ratio and limitations on debt as a percentage of total capitalization. The obligations also contain a provision restricting the payment of dividends, primarily based on the earnings of the Company and dividends previously paid. The Company was in compliance with these provisions at

September 30, 2006 and 2005. At September 30, 2006, approximately $11,123,000 of retained earnings were available for dividends.

Subsequent to September 30, 2005, Roanoke Gas Company entered into an unsecured five year variable rate note with provisions for annual renewal after the initial five year term in the amount of $15,000,000. The proceeds of this note were used to refinance the $8,000,000 unsecured note due November 30, 2005 and $4,000,000 in outstanding line of credit balance. The remainder of the proceeds were used to call the $3,000,000 collateralized term debenture due in 2016 including a call premium. The Company deferred the call premium under the provisions of SFAS No. 71, and is amortizing the balance. Also, subsequent to September 30, 2005, Bluefield Gas Company entered into an unsecured 31 month variable rate note in the amount of $2,000,000. The proceeds of this note were used to refinance the $2,000,000 unsecured note due November 2005. The Company entered into an interest rate swap agreement on the Roanoke Gas Company note for the purpose of fixing the interest rate over the term of the note. As a result of these refinancings, the Company reclassified $10,000,000 from current maturities of long-term debt and $4,000,000 from borrowings under lines-of-credit to long-term debt at September 30, 2005.

The aggregate annual maturities of long-term debt, subsequent to September 30, 2006, are as follows:

Years Ended September 30	
2007	
2008	7,000,000
2009	
2010	
2011	15,000,000
Thereafter	8,000,000
Total	$ 30,000,000

6. INCOME TAXES

The details of income tax expense (benefit) from continuing operations are as follows:

	Years Ended September 30		
	2006	2005	2004
Current income taxes:			
Federal	$ 1,434,581	$ 1,715,054	$ 92,200
State	264,060	340,027	269,562
Total current income taxes	1,698,641	2,055,081	361,762
Deferred income taxes:			
Federal	179,075	(119,974)	885,112
State	95,494	(8,237)	(91,757)
Total deferred income taxes	274,569	(128,211)	793,355
Amortization of investment tax credits	(33,251)	(34,138)	(34,138)
Total income tax expense	$ 1,939,959	$ 1,892,732	$ 1,120,979

Income tax expense from continuing operations for the years ended September 30, 2006, 2005, and 2004 differed from amounts computed by applying the U.S. Federal income tax rate of 34%, 34% and 35%*, respectively, to earnings before income taxes as a result of the following:

	Years Ended September 30		
	2006	2005	2004
Income before income taxes	$ 5,214,553	$ 5,040,372	$ 3,026,367
Income tax expense computed at statutory rate	$ 1,772,948	$ 1,713,726	$ 1,059,228
Increase (reduction) in income tax expense resulting from:			
State income taxes, net of federal income tax benefit	237,306	218,981	115,573
Amortization of investment tax credits	(33,251)	(34,138)	(34,138)
Other net	(37,044)	(5,837)	(19,684)
Total income tax expense	$ 1,939,959	$ 1,892,732	$ 1,120,979

* The gain on sale of propane assets in 2004 resulted in an increase in the federal income tax rate to 35%. In 2005, the federal tax rate returned to 34% as taxable income returned to normal levels.

The tax effects of temporary differences that give rise to the deferred tax assets and deferred tax liabilities are as follows:

	September 30	
	2006	**2005**
Deferred tax assets:		
Allowance for uncollectibles	$ 75,433	$ 107,955
Accrued pension and post-retirement medical benefits	1,422,559	1,627,502
Accrued vacation	195,860	195,653
Over recovery of gas costs	1,364,433	
Costs of gas held in storage	875,877	819,204
Accrued gas costs		2,079,381
Deferred compensation	258,231	286,374
Other	196,745	61,956
Valuation allowance	(74,450)	(41,479)
Total deferred tax assets	4,314,688	5,136,546
Deferred tax liabilities:		
Utility plant	7,481,047	7,263,809
Accrued gas costs	140,359	
Under recovery of gas costs	190,392	863,808
Total deferred tax liabilities	7,811,798	8,127,617
Net deferred tax liability	$ 3,497,110	$ 2,991,071

The Company recorded a valuation allowance to reflect the estimated amount of deferred tax assets associated with Diversified Energy s operation in West Virginia, which may not be realized due to the uncertain availability of future taxable income. The Company also recorded a valuation allowance on the Bluefield Gas Company Net Operating Loss carryforward (NOL), which is included in Other in the table above.

7. EMPLOYEE BENEFIT PLANS

The Company sponsors both a defined benefit pension plan and a postretirement plan (Plans). The defined benefit plan covers substantially all employees and benefits fully vest after five years of credited service. Benefits paid to retirees are based on age at retirement, years of service and average compensation. The postretirement benefit plan provides certain healthcare, supplemental retirement and life insurance benefits to retired employees who meet specific age and service requirements. The Company uses a June 30 measurement date for both of these plans.

Beginning January 1, 2006, the Company eliminated drug coverage under its medical plan for Medicare eligible retirees. In its place the Company provides retirees with a reimbursement of premiums up to a maximum amount paid to a qualified prescription drug provider (PDP) whereby the PDP will provide the retiree with prescription drug coverage. The Plan change resulted in the Company s medical plan not being actuarially equivalent to Medicare Part D coverage and therefore not subject to receipt of federal subsidy payments.

The following tables set forth the benefit obligations, fair value of plan assets, and the funded status of the Plans; amounts recognized in the Company s financial statements and the assumptions used:

	Pension Benefits		Post retirement Benefits	
	2006	2005	2006	2005
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 13,488,753	$ 10,508,002	$ 9,612,853	$ 7,349,726
Service cost	477,279	327,424	164,539	128,972
Interest cost	695,593	631,731	481,368	444,267
Participant contributions			49,675	41,616
Plan amendments			(343,313)	
Actuarial (gain) loss	(2,102,764)	2,622,066	(1,193,081)	2,236,085
Propane sale		(158,553)		
Benefit payments	(456,758)	(441,917)	(505,630)	(587,813)
Benefit obligation at end of year	$ 12,102,103	$ 13,488,753	$ 8,266,411	$ 9,612,853
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 8,424,279	$ 7,722,817	$ 3,586,307	$ 3,185,559
Actual return on plan assets	506,289	443,379	245,374	234,945
Employer contributions	775,000	700,000	896,830	772,000
Participant contributions			49,675	41,616
Tax payments			(60,000)	(60,000)
Benefit payments	(456,758)	(441,917)	(505,630)	(587,813)
Fair value of plan assets at end of year	$ 9,248,810	$ 8,424,279	$ 4,212,556	$ 3,586,307
Reconciliation of funded status:				
Funded status	$ (2,853,293)	$ (5,064,474)	$ (4,053,855)	$ (6,026,546)
Unrecognized actuarial loss	1,986,054	4,207,141	947,260	2,157,811
Unrecognized transition obligation			1,322,246	1,898,400
Contributions made between the measurement date and fiscal year-end	225,000	200,000	770,000	896,830
Net amount recognized	$ (642,239)	$ (657,333)	$ (1,014,349)	$ (1,073,505)
Amounts recognized in the balance sheets consist of:				
Accrued benefit liability	$ (642,239)	$ (1,284,611)		
Accumulated other comprehensive income		627,278		
Net amount recognized	$ (642,239)	$ (657,333)		

The provisions of SFAS No. 87, *Employers Accounting for Pensions*, required the Company to record an additional minimum liability of $627,278 at September 30, 2005. This liability represents the amount by which the accumulated benefit obligation exceeded the sum of the fair market value of plan assets. The $627,278 is reflected in other comprehensive income (loss) and accumulated other comprehensive income (loss), net of tax for fiscal 2005. The minimum pension liability reversed in 2006. A reconciliation of other comprehensive income is included in Note 1.

The Company amortizes the unrecognized transition obligation over 20 years.

The following table details the actuarial assumptions used in determining the projected benefit obligations and net benefit cost of the pension plan and the accumulated benefit obligations and net benefit cost of the postretirement plan for 2006, 2005 and 2004:

	Pension Benefits			Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
Assumptions related to benefit obligations:						
Discount rate	6.25%	5.25%	6.25%	6.25%	5.25%	6.25%
Expected rate of compensation increase	5.00%	5.00%	5.00%	N/A	N/A	N/A
Assumptions related to benefit costs:						
Discount rate	5.25%	6.25%	6.00%	5.25%	6.25%	6.00%
Expected long-term rate of return on plan assets	7.50%	7.50%	8.00%	7.00%	7.00%	7.00%
Expected rate of compensation increase	5.00%	5.00%	5.00%	N/A	N/A	N/A

To develop the expected long-term rate of return on assets assumption, the Company considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of each plan s portfolio. This resulted in the selection of the corresponding long-term rate of return assumptions used for each plan s assets.

	Pension Plan			Postretirement Plan		
	2006	2005	2004	2006	2005	2004
Components of net periodic benefit cost:						
Service cost	$ 477,279	$ 327,424	$ 381,588	$ 164,539	$ 128,972	$ 192,088
Interest cost	695,593	631,731	613,397	481,368	444,267	528,218
Expected return on plan assets	(628,273)	(571,881)	(508,401)	(215,026)	(185,810)	(134,519)
Amortization of unrecognized transition obligation				200,994	237,300	237,300
Recognized loss	240,307	62,395	123,553	78,969		91,641
Net periodic benefit cost	$ 784,906	$ 449,669	$ 610,137	$ 710,844	$ 624,729	$ 914,728

Actuarial estimates for the postretirement benefit plan assumed a weighted average annual rate increase in the per capita cost of covered health care benefits (i.e., medical trend rate) were 10%, 9%, and 10% for 2006, 2005 and 2004, respectively. The rates were assumed to decrease gradually to 5% by the year 2011 and remain at that level thereafter. Assumed medical trend rates have a significant effect on the amounts reported. A 1% point change in assumed healthcare cost trend rates would have the following effects:

	2006	2005
One percentage point increase:		
Aggregate of service and interest cost	$ 95,277	$ 86,495
Accumulated postretirement benefit obligation	984,945	1,243,571
One percentage point decrease:		
Aggregate of service and interest cost	$ (77,465)	$ (69,354)
Accumulated postretirement benefit obligation	(815,168)	(1,005,538)

The accumulated benefit obligation for the defined benefit pension plan was $9,106,162 and $9,908,890 in 2006 and 2005, respectively.

The Company s target and actual asset allocation in the pension and postretirement benefit plans as of June 30 were:

	Pension Plan			Postretirement Benefit Plan		
	Target	2006	2005	Target	2006	2005
Asset category:						
Equity securities	50%-70%	61%	63%	35%-65%	50%	55%
Debt securities	30%-50%	36%	34%	35%-65%	42%	40%
Other	0%-20%	3%	3%	0%-20%	8%	5%

The primary objectives of the Company s investment policies are to maintain investment portfolios that diversify risk through prudent asset allocation parameters, achieve asset returns that meet or exceed the plans actuarial assumptions, achieve asset returns that are competitive with like institutions employing similar investment strategies and meet expected future benefits. The investment policy is periodically reviewed by the Company and a third-party fiduciary.

The Company expects to contribute $600,000 to its pension plan and $700,000 to its postretirement benefit plan in 2007.

The following table reflects expected future benefit payments.

Fiscal year ending September 30	Pension Plan	Postretirement Benefit Plan
2007	$ 452,000	$ 474,000
2008	451,000	485,000
2009	462,000	489,000
2010	479,000	500,000
2011	505,000	510,000
2012-2016	3,074,000	2,748,000

The Company also sponsors a defined contribution plan/401k (Plan) covering all employees who elect to participate. Employees may contribute from 1% to 50% of their annual compensation to the Plan, limited to a maximum annual amount as set periodically by the Internal Revenue Service. The Company made annual matching contributions to the plan through December 31, 2003, based on 70% of the net participants first 6% in contributions. Beginning in January 2004, that matching formula changed to match 100% on the participants first 3% of contributions and 50% on the next 3% of contributions. Company matching contributions were $233,327, $229,441 and $254,121 for 2006, 2005 and 2004, respectively.

8. COMMON STOCK OPTIONS

The Company s stockholders approved the RGC Resources, Inc. Key Employee Stock Option Plan (KESOP). The KESOP provides for the issuance of common stock options to officers and certain other full-time salaried employees to acquire a maximum of 100,000 shares of the Company s common stock. The KESOP requires each option s exercise price per share to equal the fair value of the Company s common stock as of the date of the grant. As of September 30, 2006, the number of shares available for future grants under the KESOP is 2,000 shares.

The aggregate number of shares under option pursuant to the RGC Resources, Inc. Key Employee Stock Option Plan are as follows:

	Number of Shares	Weighted-Average Exercise Price	Option Price Per Share
Options outstanding, September 30, 2003	71,500	$ 19.049	$ 15.500- $ 20.875
Options exercised	(18,000)		
Options expired			
Options outstanding, September 30, 2004	53,500	$ 19.288	$ 15.500- $ 20.875
Options exercised	(7,500)		
Options expired			
Options outstanding, September 30, 2005	46,000	$ 19.545	$ 16.875- $ 20.875
Options exercised	(2,000)		
Options expired			
Options outstanding, September 30, 2006	44,000	$ 19.485	$ 16.875- $ 20.875

	Shares	Remaining Life (Years)	Exercise Price
	4,000	0.1	16.875
	8,500	1.3	20.625
	9,000	3.2	20.875
	7,000	4.2	19.250
	9,000	5.2	19.360
	6,500	6.2	18.100
Weighted average	44,000	3.6	$ 19.485

Under the terms of the KESOP, the options become exercisable six months from the grant date and expire ten years subsequent to the grant date. All options outstanding were fully vested and exercisable at September 30, 2006 and 2005. No options were granted in 2006, 2005 and 2004. The Company received $41,750 from the exercise of options in 2006.

9. OTHER STOCK PLANS

Dividend Reinvestment and Stock Purchase Plan

The Company offers a Dividend Reinvestment and Stock Purchase Plan (DRIP) to shareholders of record for the reinvestment of dividends and the purchase of additional investments of up to $40,000 per year in shares of common stock of the Company. Under the DRIP plan, the Company issued

29,721, 20,349 and 40,190 shares in 2006, 2005 and 2004, respectively. As of September 30, 2006, the Company had 315,891 shares available for issuance.

Restricted Stock Plan

The Board of Directors of the Company implemented the Restricted Stock Plan for Outside Directors effective January 27, 1997. The Plan is applicable to not more than 50,000 shares of Resources common stock. Under the Plan, a minimum of 40% of the monthly retainer fee paid to each non-employee director of Resources is paid in shares of common stock (Restricted Stock). The number of shares of Restricted Stock is calculated each month based on the closing sales price of Resources common stock on the NASDAQ National Market on the first day of the month, if the first day of the month is a trading day, or if not, the first trading day prior to the first day of the month. Beginning in fiscal 1998, a participant can, subject to approval of the Board, elect to receive up to 100% of his retainer fee for the fiscal year in Restricted Stock. Such election cannot be revoked or amended during the fiscal year.

The shares of Restricted Stock of Resources issued under the Plan will vest only in the case of a participant s death, disability, retirement (including not standing for reelection to the Board), or in the event of a change in control of Resources. There is no option to take cash in lieu of stock upon vesting of shares under the Plan. The Restricted Stock may not be sold, transferred, assigned or pledged by the participant until the shares have vested under the terms of the Plan. At the time the Restricted Stock vests, a certificate for vested shares will be delivered to the participant or the participant s beneficiary.

The shares of Restricted Stock will be forfeited to Resources by a participant s voluntary resignation during his term on the Board or removal for cause as a director. Subject to the terms of the Plan, a participant, as owner of the Restricted Stock, has all rights of a shareholder, including but not limited to, voting rights, the right to receive cash or stock dividends, and the right to participate in any capital adjustment of Resources. Resources requires that all dividends or other distributions paid on shares of Restricted Stock be automatically sequestered and reinvested on an immediate or deferred basis in additional Restricted Stock.

The directors received a total of 4,038 shares of Restricted Stock in fiscal 2006, representing $83,080 in compensation and $19,662 in dividends reinvested. The directors also received 3,366 shares of Restricted Stock in fiscal 2005, representing $68,601 in compensation and $18,770 in dividends reinvested and 3,642 shares of Restricted Stock in fiscal 2004, representing $69,717 in compensation and $17,873 in dividends reinvested. As of September 30, 2006, the Company had 23,811 shares available for issuance.

Stock Bonus Plan

Under the Stock Bonus Plan, executive officers are encouraged to own a position in the Company s common stock of at least 50% of the value of their annual salary. To promote this policy, the Plan provides that all officers with stock ownership positions below 50% of the value of their annual salaries must, unless approved by the Compensation Committee of the Board of Directors, receive no less than 50% of any performance bonus in the form of Company common stock. Under the Stock Bonus Plan, the Company issued 3,899, 2,314 and 344 shares valued at $101,438, $61,895 and $7,889, respectively, in 2006, 2005 and 2004. As of September 30, 2006, the Company had 26,241 shares available for issuance.

10. RELATED-PARTY TRANSACTIONS

Certain of the Company s directors and officers are affiliated with companies that render services or sell products to the Company or are associated with companies that purchase natural gas from Resources discontinued energy marketing operations. Management believes such transactions are entered into on terms equivalent to normal business terms.

11. ENVIRONMENTAL MATTER

Both Roanoke Gas Company and Bluefield Gas Company operated manufactured gas plants (MGPs) as a source of fuel for lighting and heating until the early 1950 s. A by-product of operating MGPs was coal tar, and the potential exists for on-site tar waste contaminants at the former plant sites. The extent of contaminants at these sites, if any, is unknown at this time. An analysis at the Bluefield Gas Company site indicates some soil contamination. The Company, with concurrence of legal counsel, does not believe any events have occurred requiring regulatory reporting. Further, the Company has not received any notices of violation or liabilities associated with environmental regulations related to the MGP sites and is not aware of any off-site contamination or pollution as a result of prior operations. Therefore, the Company has no plans for subsurface remediation at the MGP sites. Should the Company eventually be required to remediate either site, the Company will pursue all prudent and reasonable means to recover any related costs, including insurance claims and regulatory approval for rate case recognition of expenses associated with any work required. A stipulated rate case agreement between the Company and the West Virginia Public Service Commission recognized the Company s right to defer MGP clean-up costs, should any be incurred, and to seek rate relief for such costs. If the Company eventually incurs costs associated with a required clean up of either MGP site, the Company anticipates recording a regulatory asset for such clean-up costs to be recovered in future rates. Based on anticipated regulatory actions and current practices, management believes that any costs incurred related to this matter will not have a material effect on the Company s financial condition or results of operations.

12. COMMITMENTS

Due to the nature of the natural gas distribution business, the Company has entered into agreements with both suppliers and pipelines to contract for natural gas commodity purchases, storage capacity and pipeline delivery capacity.

The Company obtains most of its regulated natural gas supply from the asset management contracts between Roanoke Gas Company and Bluefield Gas Company and the asset manager. The Company uses an asset manager to assist in optimizing the use of its transportation, storage rights, and gas supply inventories to provide a secure and reliable source of natural gas supply.

Under the same asset manager contract mentioned above, the Company designated the asset manager as agent for their storage capacity and all gas balances in storage. The asset manager provides agency service and manages the utilization of storage assets and the corresponding withdrawals from and injections into storage. The Company retains physical ownership of storage. Under the provision of the asset management contract, the Company has an obligation to purchase its winter storage requirements during the spring and summer injection periods at market price.

The Company also has contracts for pipeline and storage capacity extending for various periods. These capacity costs and related fees are valued at tariff rates in place as of September 30, 2006. These rates may increase or decrease in the future based upon rate filings and rate orders granting a rate change to the pipeline or storage operator.

The following schedule reflects the financial and volumetric obligations as of September 30, 2006 for each of the years presented:

Fiscal Year Ended September 30,	Fixed Price Contracts Pipeline and Storage Capacity	Market Price Contracts Natural Gas Contracts (Decatherms)
2007	$ 10,827,540	2,369,675
2008	10,557,540	338,525
2009	10,557,540	
2010	10,557,540	
2011	10,557,540	
2012-2020	39,476,234	

The Company purchased approximately $59,400,000 and $56,300,000 in gas under the asset management contracts in fiscal 2006 and 2005. These contracts began in November 2004.

The Company has historically entered into derivative financial contracts for the purpose of hedging the price of natural gas. As of September 30, 2006, the Company had derivative swap arrangements to hedge for 720,000 decatherms of natural gas for the winter period at a price of $9.92 per decatherm; see *Derivative and Hedging Activities in* Footnote 1 for more information.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying value of cash and cash equivalents, temporary cash investments, accounts receivable, accounts payable and borrowings under lines of credit are a reasonable estimate of fair value due to their short-term nature and because the rates of interest paid on borrowings under lines of credit approximate market rates.

The fair value of long-term debt is estimated by discounting the future cash flows of each issuance at rates currently offered to the Company for similar debt instruments of comparable maturities. The carrying amounts and approximate values for the years ended September 30, 2006 and 2005 are as follows:

	2006		2005	
	Carrying Amounts	Approximate Fair Value	Carrying Amounts	Approximate Fair Value
Long-term debt	$ 30,000,000	$ 31,009,682	$ 30,000,000	$ 31,667,266

Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of September 30, 2006 and 2005 are not necessarily indicative of the amounts the Company could have realized in market exchanges.

14. ASSET RETIREMENT OBLIGATIONS

The Company adopted FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), as of September 30, 2006. FIN 47 requires that a liability be recognized for an asset retirement obligation which is conditional based on the occurrence of a future event even if the timing or method of settlement is uncertain. SFAS No. 143 and FIN 47 require entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost, thereby increasing the carrying amount of the underlying asset. In subsequent periods, the liability is accreted, and the capitalized cost is depreciated over the useful life of the underlying asset. Under the provisions of FIN 47, the Company recorded asset retirement obligations for its future legal obligations related to retiring its distribution system pipeline including both natural gas mains and services, although the timing of such retirements is uncertain. Including the reclassification of $2,227,460 from a regulatory liability, the Company recorded asset retirement obligations of $2,682,138 related to the future legal costs of retirement. Of this amount, $726,284 was recorded as an additional cost of the underlying utility plant with $271,606 in accumulated depreciation. If the provisions of FIN 47 had been applied to all periods presented, the Company would have reported an asset retirement obligation of approximately $2.6 million and $2.5 million at September 30, 2005 and October 1, 2004, respectively.

The Company s composite depreciation rates include a component to provide for the cost of retirement of assets. As a result, the Company accrues estimated cost of retirement of its utility plant through depreciation expense and creates a corresponding regulatory liability in accordance with the provisions of SFAS No. 71. The costs of retirement considered in the development of the depreciation component include those costs associated with the legal liability as defined under SFAS No. 143 and FIN 47. Therefore, at the time of adoption of FIN 47, the Company reclassified a portion of its regulatory liability for cost of retirement to asset retirement obligations for the legal liability as determined above. If the legal obligations would exceed the regulatory liability provided for in the depreciation rates, the Company would establish a regulatory asset for such difference with the anticipation of future recovery through rates charged to customers.

15. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Quarterly financial data for the years ended September 30, 2006 and 2005 is summarized as follows:

2006	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Operating revenues	$ 43,919,357	$ 38,457,996	$ 12,959,458	$ 12,460,939
Gross margin	$ 7,741,984	$ 8,849,907	$ 4,866,475	$ 4,607,077
Operating income	$ 2,906,148	$ 4,040,629	$ 535,850	$ 223,234
Net income (loss) from continuing operations	$ 1,382,346	$ 2,072,464	$ 9,095	$ (189,311)
Net income (loss) from discontinued operations	$ 69,836	$ 84,610	$ (66,054)	$ 148,545
Net income (loss)	$ 1,452,182	$ 2,157,074	$ (56,959)	$ (40,766)
Basic earnings (loss) per share				
Continuing operations	$ 0.66	$ 0.98	$	$ (0.09)
Discontinued operations	$ 0.03	$ 0.04	$ (0.03)	$ 0.07
Net income (loss)	$ 0.69	$ 1.02	$ (0.03)	$ (0.02)

2005	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenues	$ 29,197,627	$ 37,593,536	$ 15,819,714	$ 17,465,790
Gross margin	$ 7,098,318	$ 8,408,025	$ 4,924,504	$ 4,329,974
Operating income (loss)	$ 2,929,622	$ 3,785,875	$ 634,703	$ (224,117)
Net income (loss) from continuing operations	$ 1,493,680	$ 2,015,754	$ 87,482	$ (449,276)
Net income from discontinued operations	$ 131,715	$ 47,965	$ 142,043	$ 37,543
Net income (loss)	$ 1,625,395	$ 2,063,719	$ 229,525	$ (411,733)
Basic earnings (loss) per share				
Continuing operations	$ 0.73	$ 0.97	$ 0.04	$ (0.22)
Discontinued operations	$ 0.06	$ 0.03	$ 0.07	$ 0.01
Net income (loss)	$ 0.79	$ 1.00	$ 0.11	$ (0.21)

The pattern of quarterly earnings is the result of the highly seasonal nature of the business, as variations in weather conditions generally result in greater earnings during the winter months.

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