RGC RESOURCES INC
Form ARS
December 21, 2007

DEAR STOCKHOLDER:

I am pleased to report company earnings of $3.8 million or $1.75 per average diluted share outstanding. This compares with per share earnings of $1.65 in 2006 and $1.68 in 2005. These performance results are particularly gratifying given that 2005, 2006 and 2007 are the three warmest consecutive heating seasons since the 1930s. I am also pleased to report that your Board of Directors elected to raise the annualized dividend rate to $1.25 per share, a 2.5 percent increase, effective with the February 1, 2008, quarterly dividend for shareholders of record on January 17, 2008. This is the Company s tenth dividend increase since 1995 and continues our 63-year record of consecutive quarterly dividend payments to shareholders.

Fiscal 2007 was a busy regulatory year including filing and processing rate case applications with both Virginia and West Virginia Public Service Commissions, and special-purpose filings with both Commissions for approval to sell Bluefield Gas Company in West Virginia and the natural gas distribution assets of Roanoke Gas Company in Bluefield, VA. The year also included continuation of our construction program at Roanoke Gas Company to expand the natural gas distribution system and to replace older portions of the system installed decades ago when cast iron and bare steel pipe were the pipeline materials of choice.

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A final order in the Virginia rate case is pending; however, we have placed new rates into effect subject to refund of any amounts collected above the level eventually approved by the Virginia Commission. Both states approved the sale of the Bluefield operations and effective October 31, 2007, a month after our fiscal year end, RGC Resources, Inc. sold the common stock of Bluefield Gas Company to ANGD, LLC. Roanoke Gas Company sold its Bluefield area natural gas distribution assets to Appalachian Natural Gas Distribution

Company, a subsidiary of ANGD, LLC. The Company received $9.2 million in cash and a promissory note for $1.3 million in proceeds at the closing. Net proceeds remaining after retirement of outstanding loans and obligations were $3 million in cash and the $1.3 million promissory note. The Company plans to utilize the available cash from the sale to help fund the ongoing cast iron and bare steel pipeline replacement program on the Roanoke Gas distribution system.

We believe the sale of the Bluefield Gas operations is an appropriate strategic move for the Company. It will allow us to redeploy capital to the Roanoke Gas utility system, which has greater growth potential and a significantly better earnings record. It will also eliminate management time spent operating a very small noncontiguous distribution system serving only 4,600 customers, with the added regulatory complexity of being a multi-state utility system.

We believe the sale of the Bluefield Gas operations is an appropriate strategic move for the Company. It will allow us to redeploy capital to the Roanoke Gas utility system, which has greater growth potential and a significantly better earnings record.

We continued to expand and renew the Roanoke Gas Company natural gas distribution system, installing 12.1 miles of new main and replacing 5.5 miles of cast iron or bare steel main with either coated steel or plastic pipe. We also installed 960 new service lines associated with customer growth and replaced 358 bare steel service lines.

We were pleased to experience continued moderate customer growth given the recent decline in the housing and mortgage sectors of the economy. We are also pleased to have completed our two-year distribution system renewal project in the City of Salem. Since starting the distribution system renewal program in 1991, the percentage of cast iron and bare steel pipeline miles to total pipeline miles has declined from 22 percent to 8 percent. During that same period the percentage of bare steel service lines to total service lines has declined from 26 percent to 7 percent.

Natural gas prices have continued their volatile trend; however, average prices are generally comparable to last year. The Company s average cost of storage gas leading into this winter was $7.27 per decatherm compared with $7.03 last year. On the national level, natural gas inventories this November were at an all time high, indicating adequate supplies for the 2007-2008 winter season. Our retail price to customers for October, November and December of 2007 was essentially the same as last year, and significantly lower than for the same period in 2005, which was negatively impacted by supply constraints from the damage to natural gas production facilities caused by hurricanes Rita and Katrina in the Gulf Coast region. Current pricing and inventory levels are positively influenced by lower space heating demand from consecutive years of warmer than normal winters.

Given that burning natural gas produces far less carbon dioxide emission per unit of energy than coal, natural gas will play an increasingly prominent role in meeting future energy needs and climate change mitigation efforts.

The longer-term natural gas price and supply outlook is far more complicated. A likely return to colder weather coupled with the steadily increasing use of natural gas to generate electricity will increase the demand for natural gas. Congress has not allowed access to the outer continental shelf on the East and West coasts for natural gas exploration and new supply development, and construction of the proposed Alaskan natural gas pipeline to the lower 48 states is not a certainty. Both Republican and Democratic controlled Congress have failed to develop a long-term comprehensive energy strategy for the nation. In addition, the current Congress is considering climate change legislation to limit growth in greenhouse gas emissions, particularly carbon dioxide. Given that burning natural gas produces far less carbon dioxide emission per unit of energy than coal, natural gas will play an increasingly prominent role in meeting future energy needs and climate change

mitigation efforts. This growing importance and demand for natural gas will certainly put pressure on prices. We hope it will also pressure legislative and regulatory bodies to allow access to new areas for exploration and development of additional supplies, along with siting approval for construction of more liquefied natural gas importation facilities to allow the United States greater access to the international natural gas market.

We are pleased to provide you with our 2007 Annual Report celebrating not only a strong performance year, but also a Company service and anniversary milestone. Calendar year 2008 will mark our 125th year of service in the Roanoke Valley. We look forward to many more years of providing safe, efficient and reliable natural gas service to our customers, competitive returns to our shareholders and fulfilling careers to our employees.

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On behalf of the Board of Directors and employees of RGC Resources, Inc., I thank you for your continuing interest in our operations and for your decision to become and remain an investor. We continue to offer a dividend reinvestment and stock purchase program, free of commission or transaction fees, for shareholders who desire automatic reinvestment of part or all of their dividends or who wish to make additional direct purchases of stock through the program. We also offer the option of book entry share ownership as a way for shareholders to avoid the need for physical possession of shares. Please contact us at 540-777-3853, or go to our website at www.rgcresources.com, if you would like additional information on either program.

Sincerely,

/s/ John B. Williamson, III
John B. Williamson, III
Chairman, President and CEO

SELECTED FINANCIAL DATA

Years Ended September 30,	2007	2006	2005	2004	2003
Operating Revenues	**$ 89,901,301**	$ 94,590,872	$ 88,600,836	$ 74,152,594	$ 66,483,648
Gross Margin	**25,221,776**	23,208,272	22,206,395	20,655,455	19,189,381
Operating Income	**7,958,279**	6,677,500	6,395,564	4,270,554	4,187,799
Net Income - Continuing Operations	**3,765,669**	2,961,802	2,916,798	1,627,165	1,485,822
Net Income - Discontinued Operations	**40,540**	549,729	590,108	11,306,848	2,042,567
Basic Earnings Per Share- Continuing Operations	**$ 1.74**	$ 1.40	$ 1.40	$ 0.80	$ 0.75
Basic Earnings Per Share- Discontinued Operations	**0.02**	0.26	0.29	5.58*	1.03
Cash Dividends Declared Per Share	**$ 1.22**	$ 1.20	$ 1.18	$ 5.67	$ 1.14
Book Value Per Share	**19.38**	18.94	18.18	17.73	16.90
Average Shares Outstanding	**2,162,803**	2,120,267	2,079,851	2,027,908	1,983,970
Total Assets	**116,332,455**	114,662,572	113,563,416	114,972,556	104,364,733
Long-Term Debt (Less Current Portion)	**23,000,000**	28,000,000	28,000,000	24,000,000	28,219,987
Stockholders Equity	**42,365,233**	40,494,868	38,157,357	36,621,522	33,857,614
Shares Outstanding at Sept. 30	**2,186,143**	2,138,595	2,098,935	2,065,408	2,003,232

* 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, but are not limited to, 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) the potential loss of large-volume industrial customers to alternate fuels, facility closings or production changes; (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 , budget or similar words or future or conditional verbs such as will, would, may are intended to identify forward-looking statements.

Forward-looking 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

OVERVIEW

Resources is an energy services company primarily engaged in the regulated sale and distribution of natural gas to approximately 55,400 residential, commercial and industrial customers in Roanoke, Virginia and the surrounding areas through its Roanoke Gas Company (Roanoke Gas) subsidiary. Natural gas service is provided at rates and for the terms and conditions set forth by the State Corporation Commission (SCC or Virginia Commission). Roanoke Gas currently holds the only franchises and/or certificates of public convenience and necessity to distribute natural gas in its Virginia service areas. These franchises are effective through January 1, 2016. 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 regulated sale and distribution of natural gas to Bluefield, West Virginia, the Town of Bluefield, Virginia and surrounding areas through its Bluefield Gas Company (Bluefield Gas) subsidiary and the Bluefield division of Roanoke Gas (collectively called Bluefield Operations). On February 16, 2007, Resources entered into a Purchase and Sale Agreement for the sale of Bluefield Gas stock and on the same date Roanoke Gas entered into a Purchase and Sale Agreement for the sale of its natural gas distribution assets located in the Town of Bluefield and the County of Tazewell, Virginia. The Bluefield Operations represent approximately 4,600 customers of the total 60,000 customers of Resources as of September 30, 2007. The sale of the Bluefield stock and the assets of the Bluefield division of Roanoke Gas was closed effective as of October 31, 2007, and the corresponding activities have been classified as discontinued operations.

Resources also provided unregulated energy products through Diversified Energy Company, which operated as Highland Energy Company. Highland Energy brokered natural gas to industrial and commercial transportation customers of Roanoke Gas and Bluefield Gas. In August 2006, Diversified Energy Company sold its energy marketing operations. These operations are also classified as discontinued operations.

Please see footnote 2 and the Discontinued Operations section below for further discussion regarding the sale of the Bluefield Operations and energy marketing operations.

With the exception of the Discontinued Operations section below, all discussion and analysis excludes the activities of Bluefield Gas, the Bluefield division of Roanoke Gas and Highland Energy.

Winter weather conditions and volatility in natural gas prices both have a direct influence on the quantity of natural gas sales, 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 is 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 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 2006 through March 2007 were approximately 10% less than the 30-year average. As the level of degree-days fell outside the 6% band, the Company realized approximately $439,000 in additional revenues from continuing operations and billed the shortfall to customers accordingly. The Company realized approximately $316,000 and $420,000 in additional revenues from the WNA in fiscal 2006 and 2005, respectively.

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, due to increasing demand and limitations to accessible supply, may influence the level of sales due to conservation efforts by customers or by switching to an alternative fuel, particularly in the industrial market. In addition, increasing prices may increase the level of bad debts due to customers inability to afford the higher prices. Minimal hurricane activity during 2007, a warmer than normal early fall season and adequate storage supplies have contributed to stable natural gas prices; however, extended periods of colder than normal weather or supply disruptions could result in increasing natural gas commodity prices. The Company has an approved rate structure in place that mitigates the impact of financing costs of inventory related to rising natural gas prices. Under this rate structure, Roanoke Gas accrues revenue to cover the financing costs or carrying costs related to the level of investment in natural gas inventory. During times of rising gas costs and rising inventory levels, the company recognizes revenues to offset higher financing costs associated with higher inventory balances. Conversely, during times of decreasing inventory costs and lower inventory balances, the Company would recognize less carrying cost revenue as the financing costs would be less. The Company recognized approximately $1,955,000, $1,993,000 and $1,692,000 in carrying cost revenues for the years ended September 30, 2007, 2006 and 2005, respectively.

For the fiscal year ended September 30, 2007, the implementation of a $1.7 million non-gas rate increase and nominal increases in natural gas sales volumes provided for an increase in income from continuing operations of more than $800,000, more than offsetting increases in operating, maintenance and depreciation expenses.

PERFORMANCE GRAPH

COMPARE 5-YEAR CUMULATIVE TOTAL RETURN

AMONG RGC RESOURCES, INC., S&P UTILITIES AND HEMSCOTT GROUP INDEX

ASSUMES $100 INVESTED ON OCT. 1, 2002

ASSUMES DIVIDEND REINVESTED

FISCAL YEAR ENDING SEPT. 30, 2007

	2002	2003	2004	2005	2006	2007
RGC Resources, Inc.	100.00	133.82	170.47	200.26	205.24	223.85
Hemscott Group Index	100.00	125.53	153.93	207.99	241.82	302.33
S&P Utilities	100.00	122.67	146.70	203.43	213.14	258.22

RESULTS OF OPERATIONS   CONTINUING OPERATIONS

Fiscal Year 2007 Compared With Fiscal Year 2006

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

Year Ended September 30,	**2007**	**2006**	**Increase/ (Decrease)**	**Percentage**
Regulated Natural Gas (DTH)				
Tariff Sales	**6,802,773**	6,660,887	141,886	2%
Transportation	**2,735,456**	2,853,500	(118,044)	-4%
Total	**9,538,229**	9,514,387	23,842	0%
Heating Degree Days (Unofficial)	**3,735**	3,714	21	1%

Total natural gas sales volumes were essentially unchanged from the prior fiscal year as total heating degree days for the year ended September 30, 2007 (fiscal 2007) only increased by 1%. Tariff sales, consisting primarily of the more weather sensitive residential and commercial customers, increased by 2% reflecting a partial rebound from the customer conservation efforts experienced in fiscal 2006. Excluding the industrial customer sales component of tariff sales, which tend to be used more in processing activities rather than for heating, total weather sensitive sales volumes increased by more than 4%. Combined, industrial sales and transportation sales declined by 8% primarily due to circumstances that began during fiscal 2006: a full-year effect of an industrial customer that converted a majority of its processes to utilize coal and two smaller industrial customers that closed their operations in the Roanoke area. The remaining reduction in volume was attributable to lower natural gas consumption due to changes in production activities.

Operating Revenues The table below reflects operating revenues.

Year Ended September 30,	**2007**	**2006**	**Increase/ (Decrease)**	**Percentage**
Gas Utilities	**$ 89,175,661**	$ 93,746,408	$ (4,570,747)	-5%
Other	**725,640**	844,464	(118,824)	-14%
Total Operating Revenues	**$ 89,901,301**	$ 94,590,872	$ (4,689,571)	-5%

The reduction in operating revenues resulted from lower natural gas costs reflected in the billing rates more than offsetting the implementation of base rate increases and slightly higher sales volumes. The average per unit cost of natural gas declined by 11%.

Gross Margin - The table below reflects gross margins.

Year Ended September 30,	**2007**	**2006**	**Increase/ (Decrease)**	**Percentage**
Gas Utilities	**$ 24,833,279**	$ 22,860,718	$ 1,972,561	9%
Other	**388,497**	347,554	40,943	12%
Total Gross Margin	**$ 25,221,776**	$ 23,208,272	$ 2,013,504	9%

Gas utility margins increased due to the combination of a 2% increase in tariff sales and the implementation of a non-gas rate increase. The increase in tariff sales, as discussed above, reflects a reversal of customers energy conservation efforts in the prior year presumably in response to high natural gas prices during the winter of fiscal 2006. In October 2006, Roanoke Gas placed increased non-gas rates into effect subject to refund pending a final order from the Virginia Commission. In April 2007, Roanoke Gas received a final rate order approving an increase in non-gas rates of more than $1,600,000 based on normal winter weather. The rate increase provided for both a higher customer base charge, the flat monthly fee billed to each natural gas customer, and volumetric rate. As a result of the rate increase and higher tariff sales, customer base charges accounted for approximately $496,000 of the increase in margin and volumetric sales margins accounted for approximately $1,521,000. The remainder of the difference in margin resulted from a reduction of $45,000 in inventory carrying cost and other revenues.

Other margins increased by $40,943 primarily due to billings related to temporary work performed in the unregulated operations of Roanoke Gas.

Other Operating Expenses Operations expenses increased $347,534, or 3%, in fiscal 2007 compared with fiscal 2006 as increases in professional and contractor services and reductions in capitalized overheads more than offset declines in bad debt expense and employee benefit costs. Operations labor and contractor expenses increased by $353,000 associated with an enhanced leak survey initiative on the distribution system pipeline, increased computer network reliability and security program assessments and employee compensation. The Company also reduced the level of capital activity and the production of LNG (liquefied natural gas) resulting in a $233,000 reduction of capitalized overheads. Professional services increased $160,000 related to Sarbanes-Oxley 404 related control testing and documentation, increased actuarial work required to implement SFAS No. 158, fees to obtain consent reviews from prior external auditors and additional audit work associated with discontinued operations. Bad debt expense declined by $234,000 due to strong collection efforts and improved aging due to the warm heating season and stable energy prices. Employee benefit expenses decreased due to a $324,000 reduction in pension and other post employment benefit costs attributable to an increase in the discount rate used to determine the actuarial expense for the current year. The remaining increases were attributable to a variety of other minor expense increases.

Maintenance expenses increased by $133,098, or 10%, due to a higher level of distribution pipeline maintenance associated with increased pipeline leak survey activity and increased general facility maintenance.

General taxes remained virtually unchanged increasing by $16,356, or 1%, in fiscal 2007 compared to fiscal 2006 due to increased property taxes associated with greater levels of taxable property.

Depreciation expense increased $235,737, or 6% due to capital expenditures associated with system expansion for adding new natural gas customers and pipeline and facility renewal projects.

Interest Expense Total interest expense for fiscal 2007 decreased $69,209, or 3%, from fiscal 2006, as the total average debt outstanding during the year decreased by 8% while the average effective interest rate on total debt increased from 6.3% to 6.6%.

Debt Summary

Year Ended September 30,	2007	2006	Increase/ (Decrease)	Percentage
Average Daily Balance:				
Long-term Fixed Rate Debt	28,000,000	27,275,708	724,292	3%
Short-term Variable Rate Debt	2,029,016	5,402,310	(3,373,294)	-62%
Total Debt	30,029,016	32,678,018	(2,649,002)	-8%
Average Interest Rate:				
Long-term Fixed Rate Debt	6.7%	6.7%	0.0%	0%
Variable Rate Debt	5.8%	4.9%	0.9%	18%

The reduction in interest expense corresponds to a 62% decline in the average outstanding balance under the line of credit even though short-term interest rates rose 18% during the period. The combination of lower average natural gas inventories, higher customer credit balances under the budget payment program, greater level of over-collection of gas costs during fiscal 2007 compared to fiscal 2006 and improved earnings all contributed to reducing the overall average borrowing requirements.

Income Taxes Income tax expense from continuing operations increased $533,993, or 31% from fiscal 2006 corresponding to a 29% increase in pre-tax earnings. The effective tax rate for fiscal 2007 was 37.3% compared to 36.5% in fiscal 2006.

Net Income and Dividends Income from continuing operations for fiscal 2007 was $3,765,669 compared to fiscal 2006 income from continuing operations of $2,961,802. The improvement in income from continuing operations derived primarily from the non-gas cost rate increase, which more than offset the impact of increases in operations and maintenance expenses. Basic and diluted earnings per share from continuing operations were $1.74 and $1.73 in fiscal 2007 compared with $1.40 and $1.39 in fiscal 2006, respectively. Dividends per share of common stock were $1.22 in fiscal 2007 and $1.20 in fiscal 2006.

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	6,660,887	7,174,230	(513,343)	-7%
Transportation	2,853,500	3,202,923	(349,423)	-11%
Total	9,514,387	10,377,153	(862,766)	-8%
Heating Degree Days (Unofficial)	3,714	3,783	(69)	-2%

Tariff sales, primarily consisting of residential and commercial usage, declined 7% for the year ended September 30, 2006 (fiscal 2006)compared to the year ended September 30, 2005 (fiscal 2005) 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 fiscal 2005. The reduction in transporting volumes appeared to be related to a combination of fuel switching and other economic factors. Nearly half of the reduction in transporting volumes related to one industrial customer that converted a majority of its processes to utilize coal to lower energy costs. Most of the remaining reduction was related to production activities and two 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	$ 93,746,408	$ 87,752,669	$ 5,993,739	7%
Other	844,464	848,167	(3,703)	0%
Total Operating Revenues	$ 94,590,872	$ 88,600,836	$ 5,990,036	7%

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 16%.

Gross Margin The table below reflects gross margins.

Year Ended September 30,	2006	2005	Increase/ (Decrease)	Percentage
Gas Utilities	$ 22,860,718	$ 21,716,619	$ 1,144,099	5%
Other	347,554	489,776	(142,222)	-29%
Total Gross Margin	$ 23,208,272	$ 22,206,395	$ 1,001,877	5%

Regulated natural gas margins increased by $1,144,099, or 5%, even though total delivered volume (tariff and transporting) decreased by 862,766 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. Roanoke Gas Company placed increased non-gas rates into effect during the first quarter of fiscal 2006 subject to refund pending a final order from the Virginia Commission. The rate increase 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 $414,000 and volumetric margins increased by approximately $400,000, including the impact of reduced sales volumes and lower WNA billings. Carrying cost revenues increased by approximately $301,000 due to a combination of higher average storage gas inventory during the current fiscal year and rising interest rates.

Other margins decreased by $142,222 due to the expiration of the services agreement to provide billing, facility and other services to the acquirer of Highland Propane Company.

Other Operating Expenses Operations expenses increased $495,176, or 5%, in fiscal 2006 compared with fiscal 2005 primarily as a result of net higher employee benefit costs. 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 under the self-insured program 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 $414,000 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. The increased benefit costs also served to increase the benefit capitalization factor as a percent of labor which provided for an increase of $130,000 in expenses capitalized in fiscal 2006 as compared to fiscal 2005.

Maintenance expenses decreased by $34,889, or 3%, as the level of leak repairs, facility maintenance and transmission right-of-way clearing were comparable with the prior fiscal year.

General taxes increased $63,125, or 6%, in fiscal 2006 compared to fiscal 2005 due to increased property taxes associated with greater levels of taxable property.

Depreciation expense increased $196,529, 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 $48,117 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 $300,479, or 18%, from fiscal 2005, as the total average debt outstanding during the year increased by 11% while the average effective interest rate on total debt increased from 6.1% to 6.4%.

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%
Short-term Variable Rate Debt	5,402,310	5,317,290	85,020	2%
Total Debt	32,678,018	29,317,290	3,360,728	11%
Average Interest Rate:				
Long-term Fixed Rate Debt	6.7%	6.8%	-0.1%	-1%
Variable Rate Debt	4.9%	2.9%	2.0%	69%

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 fiscal 2005. The increase in interest rates on short-term and variable rate debt was attributable to Federal Reserve policy designed to control inflation. The average effective interest rate on the Company s variable rate lines-of-credit increased by 195 basis points, or 69%, over fiscal 2005.

Income Taxes Income tax expense from continuing operations decreased $15,430, or 1 % from fiscal 2005 as pre-tax earnings reflected a slight increase. The effective tax rate for fiscal 2006 was 36.5% compared to 37.1% in fiscal 2005.

Net Income and Dividends Income from continuing operations for fiscal 2006 was $2,961,802 as compared to fiscal 2005 income from continuing operations of $2,916,798. 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 $1.40 and $1.39 in fiscal 2006 and 2005. Dividends per share of common stock were $1.20 in fiscal 2006 and $1.18 in fiscal 2005.

DISCONTINUED OPERATIONS

As discussed in footnote 2 of the financial statements, on February 16,2007, Resources entered into a Purchase and Sale Agreement with ANGD, LLC (ANGD) for the sale of all of the capital stock of Bluefield Gas to ANGD and Roanoke Gas entered into an Asset Purchase and Sale Agreement with Appalachian Natural Gas Distribution Company (Appalachian) for the sale of Roanoke Gas natural gas distribution assets located in the Town of Bluefield and the County of Tazewell, Virginia, (Bluefield division of Roanoke Gas Company) to Appalachian, which is a wholly owned subsidiary of ANGD. All of the 3,500 customers of Bluefield Gas and 1,100 Bluefield division of Roanoke Gas Company customers are covered by these sale agreements. The sales price of the stock is equal to the book value of Bluefield Gas net assets on the date of closing. The sales price of the Virginia assets is equal to the book value of net plant plus 1% plus the book value of accounts receivable, natural gas inventory, and certain other listed current assets, subject to mutually agreed upon or arbitrated purchase price adjustments determined subsequent to the closing date but no later than 230 days after closing. $1,300,000 of such sale price is payable in the form of a subordinated promissory note from ANGD with a 5-year term and a 15-year amortization schedule with annual principal payments and quarterly interest payments at a 10% interest rate. As a part of the Purchase and Sale Agreement, Resources and Roanoke Gas will provide certain customer billing, gas control, regulatory and administrative services for

Bluefield Gas and Appalachian on mutually agreeable terms. The length of time this services agreement will be in place will be dependent on the time it takes Bluefield Gas and Appalachian to assume these processes in their own operations; however, management expects most of the services to be fully assumed within one year of closing.

Although the Purchase and Sale Agreement with ANGD for the sale of the capital stock of Bluefield Gas provides for a sales price substantially equal to the book value of Bluefield s net assets on the date of closing, the underlying tax basis that Resources has in the stock is significantly less than the book basis. This lower tax basis has resulted in the recording of an estimated income tax expense attributable to the anticipated taxable gain for the excess of the book basis of the assets over the tax basis. The current estimate of tax liability expected to be realized on this transaction is reflected as part of income tax expense in discontinued operations.

The Company received regulatory approvals from the respective regulatory commissions in Virginia and West Virginia prior to the end of the Company s fiscal year and both transactions closed effective as of October 31, 2007. As the likelihood of the completion of these transactions met the probable definition of SFAS No. 144 prior to September 30, 2007, the activities associated with the Bluefield Operations were reclassified as Discontinued Operations. SFAS No. 144 also requires depreciation to be suspended on those assets classified as held for sale. Due to regulatory requirements, depreciation expense continued on those assets included as held for sale since June 2007 when those assets were reclassified. The total depreciation expense related to those assets while classified as held for sale was approximately $110,000. At closing the Company received payment of $9,000,000 and a subordinated note of $1,300,000 based on estimated values as of October 31, 2007. Determination of the final cash settlement will be made following the reporting of October s results for the Bluefield Operations and mutual agreement of the final valuations of the related accounts, which may be no later than 230 days from the date of closing.

In the short-term, the sale of the Bluefield Operations could result in lower earnings for Resources in the near term. The Bluefield Operations had pre-tax operating losses of approximately $135,000, $182,000 and $279,000 for fiscal 2007, 2006 and 2005, respectively. Included in the Bluefield Operations were approximately $773,000, $732,000 and $685,000 of costs allocated from Resources or Roanoke Gas that will continue after the sale. In applying the provisions of SFAS No. 144, these continuing costs were reclassified from the discontinued operations of Bluefield Gas to the corresponding line items of continuing operations on the income statement. A portion of these continuing costs will be recovered under the services agreement with ANGD as discussed above. In addition, the $1,300,000 promissory note from ANGD will generate interest income, and the Company expects to reinvest the net after-tax proceeds from the sale of Bluefield Gas stock into Roanoke Gas to be used to reduce company debt and interest expense. In Roanoke Gas next non-gas cost rate filing, the Company will file for a return on the additional equity investment resulting from the Bluefield sale as well as for recovery of the balance of those costs retained by the Company after the sale, net of any service agreement revenue. Under this scenario, operating results could improve as the net loss from Bluefield Operations would be replaced by a return on the additional equity investment into Roanoke. Based on the most recent rate filing, the Company could earn a 10 percent return on this equity investment.

In July 2006, the Company entered into an asset purchase and sale agreement for the sale of the assets relating to its Highland Energy gas marketing business. The assets sold included the gas supply contracts between Highland Energy and its customers and related business records. The operations associated with the energy marketing business were reclassified as Discontinued Operations in accordance with the provisions of SFAS No. 144. The Company recognized approximately $233,000 gain on the sale of contracts in fiscal 2006; however, under the agreement, a portion of the sales price was deferred subject to certain provisions. As these provisions had been met, the Company recognized approximately $160,000 in gain on sale of assets in fiscal 2007 as part of discontinued operations in final settlement of the sales contract.

In June 2005, the Company sold 10 parcels of real estate consisting of bulk propane storage facilities and office space owned by Diversified Energy Company. These properties were originally part of the propane operations that were sold to Inergy Propane, LLC (Inergy) in 2004, but were retained and leased to Inergy with an option to purchase. The Company realized a net gain on the sale of real estate of approximately $153,000.

ENERGY PRICES

Energy costs represent the single largest expense of the Company with the cost of natural gas representing approximately 79% for fiscal 2007, 81% for fiscal 2006 and 81% for fiscal 2005 of the total operating expenses of the Company s natural gas utility operations.

To mitigate the impact of price volatility, Roanoke Gas uses a variety of hedging mechanisms including summer storage injections and financial instruments to reduce the volatility of spot market purchases during the winter. At September 30, 2007, the Company s natural gas storage levels were near capacity with nearly 2.56 million decatherms in storage. The Company also has financially hedged 680,000 decatherms of natural gas for the 2007-08 winter period.

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

Although rising natural gas prices are recoverable through the PGA mechanism, 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.

ASSET MANAGEMENT

Roanoke Gas Company uses 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 Roanoke Gas a monthly utilization fee, which is used to reduce the cost of gas for customers. In October 2007, Roanoke Gas executed a new three-year agreement with a new asset manager to provide the same services including the payment of a monthly utilization fee.

CAPITAL RESOURCES AND LIQUIDITY

Due to the capital intensive nature of Resources utility business 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 were $6.0 million, $7.2 million and $6.7 million for fiscal 2007, 2006 and 2005, respectively. Operating cash flow provided by depreciation contributed approximately $4.3 million in support of capital expenditures, or approximately 72% of the total investment. In fiscal 2006 and 2005, such cash flow provided 57% and 58%, respectively. It is anticipated that future capital expenditures will remain consistent with current levels and 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.

On March 20, 2007, 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. 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 Company s available limits under the remaining term of the line-of-credit agreements excluding Bluefield Gas $6,000,000 available limit that was terminated at closing are as follows:

Beginning	**Continuing Operations**
September 30, 2007	$ 17,000,000
November 16, 2007	21,000,000
February 16, 2008	16,000,000

At September 30, 2007, the Company had $4,808,000 outstanding under its available lines-of-credit. The average rates on debt outstanding during the year under the lines-of-credit were 5.83% in 2007, 4.86% in 2006 and 2.94% in 2005. The lines do not require compensating balances. These lines-of-credit will expire March 31, 2008, unless extended. The Company anticipates being able to extend or replace the lines-of-credit.

In November 2005, 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 retire 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 the payment of a call premium. The Company entered into an interest rate swap agreement on the note for the purpose of fixing the interest rate at 5.74% over the total term of the note.

In July 2008, Roanoke Gas $5,000,000 note matures. Management anticipates being able to obtain new financing on terms acceptable to the Company to meet the cash requirements of the maturing note.

As discussed above, the Company and Roanoke Gas closed on the sale of the Bluefield Operations effective as of October 31, 2007. On the date of closing the Company received payment of $9,000,000 and a subordinated note of $1,300,000 based on estimated values as of October 31, 2007. After payoff of Bluefield s outstanding debt at the date of closing and payment of the estimated income taxes associated with the taxable gain on sale of the stock of Bluefield Gas, the Company will increase its cash resources by approximately $3,300,000. The Company will use the net proceeds to reduce the corporate borrowing requirements under its line-of-credit agreements and to invest capital in Roanoke Gas to help fund its construction and pipeline renewal programs.

Short-term borrowings, together with internally generated funds through net income and operating cash flow, long-term debt and the sale of common stock through the Company s DRIP Plan, have been adequate to cover construction costs, natural gas purchases, tax payments, debt service and dividend payments to shareholders. Management expects such sources of funds will continue to meet future cash requirements.

Stockholders equity increased for the period by $1,870,365, primarily due to earnings and proceeds from stock issued under the DRIP Plan. The activity is summarized below:

Net income	$ 3,806,209
Dividends	(2,646,101)
DRIP	855,322
Restricted stock and stock options	327,362
Net comprehensive income	(472,427)
Increase in stockholders equity	$ 1,870,365

At September 30, 2007, the Company s consolidated long-term capitalization was 60% equity and 40% debt, compared to 59% equity and 41 % debt at September 30, 2006.

REGULATORY AFFAIRS

On September 14, 2006, Roanoke filed an application with the SCC for an expedited increase in non-gas rates to provide approximately $1,750,000 in additional revenues. The requested rates 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. In April 2007, Roanoke received the final rate order approving $1,667,940 in additional revenues. In June 2007, Roanoke completed the refund of customer billings in excess of the final approved rates plus interest. Roanoke Gas Company also filed a new request to increase non-gas rates on September 17, 2007. These new rates, designed to provide approximately $700,000 in additional revenues, were placed into effect on November 1, 2007 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 late spring of 2008.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

RGC Resources, Inc. s contractual obligations as of September 30, 2007 representing cash obligations that are considered to be firm commitments are as follows.

Payment due within the year ended September 30,

	2008	**2009**	**2010**	**2011**	**2012**	**Thereafter**
Lines-of-credit[1]	$ 4,808,000	$	$	$	$	$
Long-term debt[1]	5,000,000			15,000,000		8,000,000
Natural gas (see below)						
Pipeline and storage capacity	9,729,451	9,729,451	9,729,451	9,729,451	9,729,451	26,318,956
Total contractual obligations	$ 19,537,451	$ 9,729,451	$ 9,729,451	$ 24,729,451	$ 9,729,451	$ 34,318,956

1 Excludes interest payments attributable to the debt

Total available lines-of-credit are scheduled to expire on March 31, 2008, 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 with related fees in the amount of $74,966,211 under contracts expiring at various times through the year 2020. The Company expects to recover these costs through the PGA mechanism. The Company also has commitments to purchase natural gas at market price over the next year in the amount of 285,985 decatherms. Under the new asset management agreement executed subsequent to September 30, 2007, the Company has additional commitments to purchase the following decatherms of natural gas at market price over the next four years:

Year Ended September 30,	Decatherms	Current Price
2008	1,907,195	$ 12,728,000
2009	2,225,059	14,849,000
2010	2,225,059	14,849,000
2011	317,864	2,121,000

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.

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 occurs, 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).

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 in the consolidated statement of income and comprehensive income for the period in which the discontinuance occurred.

Revenue recognition Regulated utility sales and transportation revenues are based upon rates approved by the SCC. The non-gas cost component of rates may not be changed without a formal rate increase application and corresponding authorization by the SCC; however, the gas cost component of rates may be adjusted periodically through the PGA mechanism with approval from the SCC.

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 $1,287,362 and $1,462,878 as of September 30, 2007 and 2006.

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 footnote 7 to the consolidated financial statements, are based on 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. 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. 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 following schedule reflects the sensitivity of pension costs to changes in certain actuarial assumptions, while the other components of the calculation remain constant.

Actuarial Assumption	**Change in Assumption**	**Impact on 2007 Pension Cost**	**Impact on Projected Benefit Obligation**
Discount rate	-0.25%	$ 61,000	$ 514,000
Rate of return on plan assets	-0.25%	23,000	N/A
Rate of increase in compensation	0.25%	36,000	189,000

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 2007 Postretirement Benefit Cost**	**Impact on Accumulated Postretirement Benefit Obligation**
Discount rate	-0.25%	$ 49,000	$ 234,000
Rate of return on plan assets	-0.25%	11,000	N/A
Health care cost trend rate	0.25%	32,000	264,000

Derivatives As discussed in the Market Risk section below, the Company may hedge certain risks incurred in its operation 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.

MARKET RISK

The Company is exposed to market risks associated with commodity prices. 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 risk 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 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, 2007, the Company had collar agreements outstanding for the purpose of hedging the price of natural gas during the winter period for 680,000 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. The SCC currently allows 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.

The Company is also exposed to market risk related to changes in interest rates associated with its borrowing activities. As of September 30, 2007, the Company had $4,808,000 outstanding under its lines-of-credit. Based upon outstanding borrowings at September 30, 2007, a 100 basis point increase in market interest rates applicable to the Company s variable rate debt would have resulted in an increase in annual interest expense of approximately $48,000.

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 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 SCC 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 lower than last year, they are expected to remain above long-term historical levels. The Company has worked diligently at minimizing bad debts and bad debt write offs. However, management anticipates that future significant increases or spikes in natural gas prices could result in an increased rate of delinquencies as customers face higher natural gas bills as well as other higher energy costs. In addition, the SCC has 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 approved 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.

Actuarial Assumptions and Investment Returns RGC Resources, Inc. offers both a defined benefit pension plan and postretirement medical benefits plan. The actuarially determined expenses of each of these plans are significantly impacted by key assumptions including the discount rate, the expected return on plan assets, life expectancies and medical inflation (postretirement plan). From year to year, volatility in the discount rate has perhaps the most significant impact on determining benefit expense, the benefit obligation and corresponding funded status of each plan. For fiscal 2008, the discount remained unchanged at 6.25% and pension and postretirement expense are expected to be comparable with fiscal 2007. In addition, the actual return on plan assets also impacts the expense calculation and funded status. The Company has maintained a funding plan designed to increase plan assets and mitigate the impact of the underfunded position on both plans. However, a 10% loss on the plan assets would increase the underfunded position of the pension plan by nearly $1,100,000 and the postretirement plan by more than $500,000.

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.

Inflation As with most businesses, the Company is subject to the effect of inflationary pressures. The single greatest cost to the Company is natural gas, which represented approximately 80% of the Company s natural gas utility operations over each of the past three years. As discussed above, the PGA mechanism provides the Company with the ability to recover rising gas costs. Furthermore, rising operating and capital costs including labor, materials, contractors and other costs impact the Company s results of operations and cash requirements. To obtain relief from these rising costs from both an expense and capital exposure, the Company will periodically file a request for a non-gas rate increase. See the Regulatory Affairs section above for additional information on current filings. While both the PGA and non-gas rate increases can provide protection for rising costs, approval of the full amount requested by the SCC is not guaranteed and the approved rate adjustments ultimately placed into effect are on a lagged basis to the expenses.

CAPITALIZATION STATISTICS

Years Ended September 30,	2007	2006	2005	2004	2003
COMMON STOCK:					
Shares Issued	**2,186,143**	2,138,595	2,098,935	2,065,408	2,003,232
Continuing Operations:					
Basic Earnings Per Share	**$ 1.74**	$ 1.40	$ 1.40	$ 0.80	$ 0.75
Diluted Earnings Per Share	**$ 1.73**	$ 1.39	$ 1.39	$ 0.80	$ 0.75
Discontinued Operations:					
Basic Earnings Per Share	**$ 0.02**	$ 0.26	$ 0.29	$ 5.58*	$ 1.03
Diluted Earnings Per Share	**$ 0.02**	$ 0.26	$ 0.29	$ 5.53	$ 1.02
Dividends Paid Per Share (Cash)	**$ 1.22**	$ 1.20	$ 1.18	$ 5.67	$ 1.14
Dividends Paid Out Ratio	**69.3%**	72.3%	69.8%	88.9%	64.0%
CAPITALIZATION RATIOS:					
Long-Term Debt, Including Current Maturities	**39.8**	40.9	42.3	39.6	46.4
Common Stock And Surplus	**60.2**	59.1	57.7	60.4	53.6
Total	**100.0**	100.0	100.0	100.0	100.0
Long-Term Debt, Including Current Maturities	**$ 28,000,000**	$ 28,000,000	$ 28,000,000	$ 24,019,987	$ 29,252,359
Common Stock And Surplus	**42,365,233**	40,494,868	38,157,357	36,621,522	33,857,614
Total Capitalization Plus Current Maturities	**$ 70,365,233**	$ 68,494,868	$ 66,157,357	$ 60,641,509	$ 63,109,973

* 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**
2007			
First Quarter	$ 27.800	$ 24.770	$ 0.305
Second Quarter	28.700	24.840	0.305
Third Quarter	29.010	27.010	0.305
Fourth Quarter	28.700	25.880	0.305
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

SUMMARY OF GAS SALES & STATISTICS

Years Ended September 30,	**2007**	**2006**	**2005**	**2004**	**2003**
REVENUES:					
Residential Sales	**$ 50,791,195**	$ 52,274,204	$ 49,332,645	$ 42,826,979	$ 38,233,811
Commercial Sales	**34,566,385**	36,159,320	33,059,542	27,154,959	24,048,119
Interruptible Sales	**1,379,870**	3,054,240	3,029,697	1,234,144	1,887,212
Transportation Gas Sales	**2,254,594**	2,067,929	2,110,002	2,120,506	1,672,522
Backup Services	**3,600**	3,600	62,756	51,452	89,590
Late Payment Charges	**55,438**	70,191	55,109	71,065	96,941
Miscellaneous Gas Utility Revenue	**124,579**	116,924	102,918	92,433	50,889
Other	**725,640**	844,464	848,167	601,056	404,564
Total	**$ 89,901,301**	$ 94,590,872	$ 88,600,836	$ 74,152,594	$ 66,483,648
NET INCOME					
Continuing Operations	**$ 3,765,669**	$ 2,961,802	$ 2,916,798	$ 1,627,165	$ 1,485,822
Discontinued Operations	**40,540**	549,729	590,108	11,306,848	2,042,567
Net Income	**$ 3,806,209**	$ 3,511,531	$ 3,506,906	$ 12,934,013	$ 3,528,389
DTH DELIVERED:					
Residential	**3,778,194**	3,588,364	3,987,368	4,281,320	4,563,672
Commercial	**2,886,403**	2,793,988	2,859,471	2,937,469	3,101,259
Interruptible	**138,176**	278,535	321,860	153,714	294,172
Transportation Gas	**2,735,456**	2,853,500	3,202,923	3,391,620	2,829,700
Backup Service	**0**	0	5,531	5,530	10,727
Total	**9,538,229**	9,514,387	10,377,153	10,769,653	10,799,530
HEATING DEGREE DAYS	**3,735**	3,714	3,783	3,917	4,349
NUMBER OF CUSTOMER					
Natural Gas					
Residential	**50,371**	49,649	49,178	48,215	47,672
Commercial	**5,017**	4,948	4,939	4,903	4,900
Interruptible and Interruptible					
Transportation Service	**32**	32	36	36	37
Total	**55,420**	54,629	54,153	53,154	52,609
GAS ACCOUNT (DTH):					
Natural Gas Available	**9,744,431**	9,703,011	10,546,259	11,061,144	11,089,300
Natural Gas Deliveries	**9,538,229**	9,514,387	10,377,153	10,769,653	10,799,530
Storage-LNG	**65,279**	98,936	89,896	117,378	102,907
Company Use And Miscellaneous	**28,862**	36,321	47,568	52,440	42,902
System Loss	**112,061**	53,367	31,642	121,673	143,961
Total Gas Available	**9,744,431**	9,703,011	10,546,259	11,061,144	11,089,300
TOTAL ASSETS	**$ 116,332,455**	$ 114,662,572	$ 113,563,416	$ 114,972,556	$ 104,364,733
LONG-TERM OBLIGATIONS	**$ 23,000,000**	$ 28,000,000	$ 28,000,000	$ 24,000,000	$ 28,219,987

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 Clinic

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

Vice President Eastern Sales -

Market Analysis & Research

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: [1] [2] [3]

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)

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(1) RGC Resources, Inc.
(2) Roanoke Gas Company
(3) Diversified Energy Company
(4) RGC Ventures of Virginia, Inc.
(5) Bluefield Gas Company

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, 2007, 2006, and 2005, and Report of Independent Registered Public Accounting Firm

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RGC RESOURCES, INC. AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

RGC Resources, Inc.

Roanoke, Virginia

We have audited the accompanying consolidated balance sheet of RGC Resources, Inc. and Subsidiaries (the Company) as of September 30, 2007 and 2006, and the related consolidated statements of income and comprehensive income, stockholders equity, and cash flows for the years then ended. 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 for the year ended September 30, 2005, before the adjustment to reflect the Bluefield, Virginia and West Virginia operations and 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also 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, 2007 and 2006, and the consolidated results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

On February 16, 2007 the Company entered into agreements to sell its Bluefield, Virginia and West Virginia operations, and 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 financial statements to retroactively reflect the Bluefield, Virginia and West Virginia operations and the energy marketing business as Discontinued 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 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 financial statements taken as a whole.

As discussed in Notes 1 and 7, the Company changed its method of accounting for its defined benefit pension plan and its post retirement benefit plan to adopt Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

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

319 McClanahan Street, S.W.

Roanoke, Virginia

November 14, 2007

Member: SEC and Private Companies Practice Sections of American Institute of Certified Public Accountants

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2007 AND 2006

	2007	**2006**
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,408,317	$ 1,490,141
Accounts receivable, less allowance for doubtful accounts of $46,710 in 2007 and $26,584 in 2006	4,447,928	4,558,458
Materials and supplies	515,722	553,773
Gas in storage	19,156,833	19,932,064
Assets available for sale	12,825,344	13,726,791
Prepaid income taxes	1,649,788	879,957
Deferred income taxes	1,001,162	2,654,548
Other	455,445	392,564
Total current assets	41,460,539	44,188,296
UTILITY PROPERTY:		
In service	108,348,844	102,822,594
Accumulated depreciation and amortization	(36,424,831)	(34,447,514)
In service net	71,924,013	68,375,080
Construction work in progress	663,256	1,702,416
Utility plant net	72,587,269	70,077,496
Other assets	2,284,647	396,780
TOTAL ASSETS	$ 116,332,455	$ 114,662,572

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2007 AND 2006

	2007	2006
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 5,000,000	$
Borrowings under lines of credit	4,808,000	3,353,000
Dividends payable	667,245	643,067
Accounts payable	6,457,602	8,328,365
Customer credit balances	4,308,415	4,027,668
Customer deposits	1,439,765	1,245,508
Accrued expenses	2,106,222	3,484,476
Liabilities of assets available for sale	7,558,605	8,252,463
Over-recovery of gas costs	567,295	2,112,256
Fair value of marked-to-market transactions	86,025	1,486,699
Total current liabilities	32,999,174	32,933,502
LONG-TERM DEBT, excluding current maturities	23,000,000	28,000,000
DEFERRED CREDITS AND OTHER LIABILITIES:		
Asset retirement obligations	2,499,345	2,404,839
Regulatory cost of retirement obligations	6,043,088	5,319,198
Benefit plan liabilities	3,855,292	
Deferred income taxes	5,442,563	5,351,746
Deferred investment tax credits	127,760	158,419
Total deferred credits and other liabilities	17,968,048	13,234,202
COMMITMENTS AND CONTINGENCIES (Notes 10 and 11)		
CAPITALIZATION:		
Stockholders equity:		
Common stock, $5 par value; authorized 10,000,000 shares; issued and outstanding 2,186,143 and 2,138,595 shares in 2007 and 2006, respectively	$ 10,930,715	$ 10,692,975
Preferred stock, no par; authorized 5,000,000 shares; no shares issued or outstanding in 2007 and 2006		
Capital in excess of par value	15,466,756	14,521,812
Retained earnings	16,443,017	15,282,909
Accumulated other comprehensive loss	(475,255)	(2,828)
Total stockholders equity	42,365,233	40,494,868
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 116,332,455	$ 114,662,572

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2007, 2006, AND 2005

	2007	**2006**	**2005**
OPERATING REVENUES:			
Gas utilities	$ 89,175,661	$ 93,746,408	$ 87,752,669
Other	725,640	844,464	848,167
Total operating revenues	89,901,301	94,590,872	88,600,836
COST OF SALES:			
Gas utilities	64,342,382	70,885,690	66,036,050
Other	337,143	496,910	358,391
Total cost of sales	64,679,525	71,382,600	66,394,441
GROSS MARGIN	25,221,776	23,208,272	22,206,395
OTHER OPERATING EXPENSES:			
Operations	10,624,555	10,277,021	9,781,845
Maintenance	1,419,830	1,286,732	1,321,621
General taxes	1,130,522	1,114,166	1,051,041
Depreciation and amortization	4,088,590	3,852,853	3,656,324
Total other operating expenses	17,263,497	16,530,772	15,810,831
OPERATING INCOME	7,958,279	6,677,500	6,395,564
OTHER EXPENSES Net	24,758	12,630	60,747
INTEREST EXPENSE	1,931,444	2,000,653	1,700,174
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	6,002,077	4,664,217	4,634,643
INCOME TAX EXPENSE FROM CONTINUING OPERATIONS	2,236,408	1,702,415	1,717,845
INCOME FROM CONTINUING OPERATIONS	3,765,669	2,961,802	2,916,798
DISCONTINUED OPERATIONS:			
Income from discontinued operations net of income taxes of $835,836, $382,558 and $395,482 in 2007, 2006, and 2005, respectively	40,540	549,729	590,108
NET INCOME	3,806,209	3,511,531	3,506,906
OTHER COMPREHENSIVE INCOME (LOSS) NET OF TAX	(50,542)	377,643	(334,961)
COMPREHENSIVE INCOME	$ 3,755,667	$ 3,889,174	$ 3,171,945

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2007, 2006, AND 2005

	2007	2006	2005
BASIC EARNINGS PER COMMON SHARE:			
Income from continuing operations	$ 1.74	$ 1.40	$ 1.40
Discontinued operations	0.02	0.26	0.29
Net income	$ 1.76	$ 1.66	$ 1.69
DILUTED EARNINGS PER COMMON SHARE:			
Income from continuing operations	$ 1.73	$ 1.39	$ 1.39
Discontinued operations	0.02	0.26	0.29
Net income	$ 1.75	$ 1.65	$ 1.68
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	2,162,803	2,120,267	2,079,851
Diluted	2,173,258	2,130,720	2,093,115

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

YEARS ENDED SEPTEMBER 30, 2007, 2006 AND 2005

	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
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
Net income			3,806,209		3,806,209
Loss on hedging activities net of tax				(50,542)	(50,542)
Adoption of SFAS No. 158				(421,885)	(421,885)
Cash dividends declared ($1.22 per share)			(2,646,101)		(2,646,101)
Issuance of common stock (47,548 shares)	237,740	944,944			1,182,684
BALANCE September 30, 2007	$ 10,930,715	$ 15,466,756	$ 16,443,017	$ (475,255)	$ 42,365,233

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2007, 2006 AND 2005

	2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income from continuing operations	$ 3,765,669	$ 2,961,802	$ 2,916,798
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	4,301,102	4,064,704	3,882,593
Cost of removal of utility plant net	(252,931)	(243,015)	(213,924)
Loss on disposal of property			33,590
Gain on sale of short-term investments			(8,540)
Change in over/under recovery of gas costs	(3,027,101)	5,322,010	(3,896,107)
Deferred taxes and investment tax credits	2,003,043	55,201	(154,638)
Other noncash items net	18,201	(144,761)	96,406
Changes in assets and liabilities which provided (used) cash:			
Accounts receivable and customer deposits net	304,787	2,399,290	(948,205)
Inventories, gas in storage and prepaid gas	813,282	225,010	(4,984,889)
Other current assets	(832,712)	64,213	1,081,587
Accounts payable, customer credit balances and accrued expenses	(1,463,285)	(5,454,627)	7,052,308
Total adjustments	1,864,386	6,288,025	1,940,181
Net cash provided by continuing operating activities	5,630,055	9,249,827	4,856,979
Net cash provided by discontinued operations	991,317	1,046,633	656,916
Net cash provided by operating activities	6,621,372	10,296,460	5,513,895
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant and nonutility property	(6,004,190)	(7,175,409)	(6,685,229)
Proceeds from disposal of utility and nonutility property	12,340	3,416	83,371
Proceeds from sale of short-term investments			5,000,000
Net cash used in continuing investing activities	(5,991,850)	(7,171,993)	(1,601,858)
Net cash used in discontinued investing activities	(204,107)	(406,716)	(3,178)
Net cash used in investing activities	(6,195,957)	(7,578,709)	(1,605,036)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of long-term debt		15,000,000	
Retirement of long-term debt and capital leases		(11,000,000)	(19,987)
Net repayments under line-of-credit agreements	1,455,000	(4,672,000)	(1,049,000)
Proceeds from issuance of common stock	1,182,684	999,764	823,417
Cash dividends paid	(2,621,923)	(2,527,892)	(11,743,988)
Net cash provided by (used in) continuing financing activities	15,761	(2,200,128)	(11,989,558)
Net cash used in discontinued financing activities	(523,000)	(377,000)	(31,000)
Net cash used in financing activities	(507,239)	(2,577,128)	(12,020,558)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(81,824)	140,623	(8,111,699)
CASH AND CASH EQUIVALENTS Beginning of year	1,490,141	1,349,518	9,461,217

CASH AND CASH EQUIVALENTS End of year	$ 1,408,317	$ 1,490,141	$ 1,349,518

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2007, 2006 AND 2005

	2007	**2006**	**2005**
SUPPLEMENTAL DISCLOSURE OF CASH FLOWS INFORMATION:			
Cash paid during the year for:			
Interest	$ 2,335,713	$ 2,377,906	$ 2,131,430
Income taxes net of refunds	$ 1,952,794	$ 1,888,858	$ 912,844
Non-cash transactions:			

In 2007, 2006 and 2005, the Company entered into derivative arrangements for the purpose of hedging the cost of gas and in 2005 entered into an interest rate swap 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:

Fair value of marked-to-market transactions	$ (1,400,674)	$ 1,500,305	$ (86,962)
Over recovery of gas costs	1,482,140	(1,482,140)	
Deferred tax liability	32,655	6,896	(33,011)

In September 2007, the Company adopted FASB No. 158 (as discussed in Note 7) which resulted in the establishment of a benefit liability attributable to the Company s underfunded positions under its pension and post-retirement medical plans as well as a regulatory asset related to the portion pertaining to the regulated operations. Prior to the adoption of SFAS No. 158, the Company recorded a minimum pension liability in 2005 which reversed in 2006.

Regulatory asset	$ 1,906,068	$	$
Benefit plan liability	3,855,292		
Deferred tax liability	(258,575)	238,366	(238,366)
Accrued expenses	(1,268,764)	(627,278)	627,278

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED SEPTEMBER 30, 2007, 2006, AND 2005

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 (Roanoke Gas); Diversified Energy Company; and RGC Ventures, Inc. of Virginia, operating as Application Resources. Roanoke Gas is a natural gas utility, which distributes and sells natural gas to residential, commercial and industrial customers within its service areas in Roanoke, VA and the surrounding areas. Application Resources provides information system services to software providers in the utility industry.

Roanoke Gas is regulated by the State Corporation Commission (SCC or 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.

On February 16, 2007, Resources entered into a Purchase and Sale Agreement with ANGD, LLC for the sale of all of the capital stock of Bluefield Gas Company (Bluefield Gas), and Roanoke Gas entered into a Purchase and Sale Agreement with Appalachian Natural Gas Distribution Company for the sale of Roanoke Gas natural gas distribution assets located in the Town of Bluefield and the County of Tazewell, Virginia (Bluefield division of Roanoke Gas Company .) Both transactions closed on November 2, 2007 with an effective date of October 31, 2007. In August 2006, Resources sold the assets of Highland Energy, its energy marketing operation that brokered natural gas to industrial transportation customers of Roanoke Gas and Bluefield Gas. These operations have been reflected as discontinued operations in the consolidated financial statements of Resources. With the sale of Highland Energy, Resources has only one reportable segment as defined under SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information.* Please see footnote 2 below for further discussions on the sale of Bluefield Gas, the assets of the Bluefield division of Roanoke Gas Company and certain assets of Highland Energy.

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, 2007 and 2006 are as follows:

	September 30	
	2007	**2006**
Regulatory assets:		
Premium on early retirement of debt	$ 248,077	$ 278,454
Benefit plan assets	1,906,068	
Other	11,945	11,945
Total regulatory assets	$ 2,166,090	$ 290,399
Regulatory liabilities:		
Over-recovery of gas costs	$ 567,295	$ 2,112,256
Regulatory cost of retirement obligation	6,043,088	5,319,198
Asset retirement obligation	2,499,345	2,404,839
Other	330	2,447
Total regulatory liabilities	$ 9,110,058	$ 9,838,740

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 footnote 13.

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. The annual composite rates for utility property are determined by periodic depreciation studies that are approved by the SCC. The Virginia Commission requires Roanoke Gas to conduct a depreciation study every five years and propose new depreciation rates for approval. The results of Roanoke Gas 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 the 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 are accounted for under the provisions of SFAS No. 71. Therefore, such amounts are classified as a regulatory liability. See footnote 13 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.

Reserve for Bad Debts The Company provides an estimate for losses on accounts receivable utilizing historical information, current account balances, account aging and current economic conditions.

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, 2007 and 2006 were $1,287,362 and $1,462,878, 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 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.

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 including footnote information for 2006 and 2005 to reflect the effect of discontinued operations discussed in footnote 2. The Company reclassified non-utility property and related accumulated depreciation into the corresponding utility property accounts. The Company also reclassified refunds from suppliers due customers to accrued expenses .

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		
	2007	**2006**	**2005**
Weighted average common shares	2,162,803	2,120,267	2,079,851
Effect of dilutive securities:			
Options to purchase common stock	10,455	10,453	13,264
Diluted average common shares	2,173,258	2,130,720	2,093,115

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 in any period.

Roanoke Gas is served by multiple natural gas transmission pipelines; however, by the stage of physical interconnection with the 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 both 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.

The Company enters into collars, 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. The Virginia Commission allows 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, 2007, the Company has collar agreements outstanding for the winter period to hedge 680,000 decatherms of natural gas, and the futures price for delivery of natural gas during the periods hedged fell between the upper and lower limits of the collar contracts.

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 as defined under SFAS No. 133 for any period.

Other Comprehensive Income A summary of other comprehensive income and financial instrument activity including the effect of adopting SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*, is provided below:

Year Ended September 30, 2007	Interest Rate Swap	Natural Gas Derivative	SFAS No. 158	Total
Unrealized losses	$ (37,233)	$	$	$ (37,233)
Income tax benefit	14,134			14,134
Net unrealized losses	(23,099)			(23,099)
Transfer of realized gains to income	(44,233)			(44,233)
Income tax expense	16,790			16,790
Net transfer of realized gains to income	(27,443)			(27,443)
Net other comprehensive loss	$ (50,542)	$	$	$ (50,542)
Fair value of marked to market transactions	$ (86,025)	$	$	$ (86,025)
Accumulated comprehensive loss	$ (53,370)	$	$ (421,885)	$ (475,255)

Year Ended September 30, 2006	Interest Rate Swap	Natural Gas Derivative	Minimum 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	$ (4,559)	$ (1,482,140)	$	$ (1,486,699)
Accumulated comprehensive loss	$ (2,828)	$	$	$ (2,828)

Year Ended September 30, 2005	Interest Rate Swap	Natural Gas Derivative	Minimum 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 loss	$	8,441	$		$	(388,912)	$	(380,471)

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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 2007, 2006 and 2005 and all outstanding options were fully vested at the date of adoption.

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 the Company s first quarter of fiscal year ending September 30, 2008. 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 or cash flows.

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. The Company does not anticipate the adoption of this statement to have a material impact on the Company s financial position, results of operations or cash flows.

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* (SFAS No. 158). 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 adoption of SFAS No. 158 resulted in the Company recording an additional benefit liability of $2,586,528 associated with the net underfunded positions of its defined benefit pension plan and post-retirement benefit plan. The Company also recorded a regulatory asset of $1,906,068 associated with the regulated operations of Roanoke Gas in accordance with the provisions of SFAS No. 71 whereby the Company believes that it will continue to be able to recover the change in funded status of the plans through future rates. The Company also recognized other comprehensive loss of $421,885, net of tax, for the associated liabilities not associated with the regulated operations. Footnote 7 includes more information regarding the effect of SFAS No. 158.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement permits, but does not require, entities to choose to measure selected financial assets and liabilities at fair value. Although SFAS No. 159 does not eliminate the fair value disclosure requirements included in other accounting standards, it does provide for additional presentation and disclosures designed to facilitate comparisons between companies that choose different measurement attributes for similar assets and liabilities. The effective date of this statement is for fiscal years beginning after November 15, 2007. The Company has not completed its evaluation of this statement, nor determined the potential effect on its financial position, results of operations or cash flows.

2. DISCONTINUED OPERATIONS

On February 16, 2007, Resources entered into a Purchase and Sale Agreement with ANGD, LLC (ANGD), for the sale of all of the capital stock of Bluefield Gas Company, a wholly owned subsidiary of Resources, to ANGD. The sales price is equal to the book value of Bluefield Gas net assets on the date of closing, subject to mutually agreed upon or arbitrated purchase price adjustments determined subsequent to the closing date but no later than 230 days after Closing. In connection with the sale, (i) certain real estate will be distributed to the Company prior to Closing, (ii) inter-company receivables or payables existing between Bluefield Gas and the Company (including its other affiliates) will be settled as of Closing, and (iii) the Company will pay off Bluefield Gas outstanding debt at Closing out of the sales proceeds.

Also on February 16, 2007, Roanoke Gas entered into an Asset Purchase and Sale Agreement with Appalachian Natural Gas Distribution Company (Appalachian) for the sale of Roanoke Gas natural gas distribution assets located in the Town of Bluefield and the County of Tazewell, Virginia, (Bluefield division of Roanoke Gas Company) to Appalachian, which is a wholly owned subsidiary of ANGD. The sales price is equal to the book value of net plant plus 1% and the book value of accounts receivable, natural gas inventory, and certain other listed current assets, subject to mutually agreed upon or arbitrated purchase price adjustments determined subsequent to the closing date but no later than 230 days after Closing. $1,300,000 of such sales price is payable in the form of a promissory note from ANGD with a 5-year term and a 15-year amortization schedule with annual principal payments and quarterly interest payments at a 10% interest rate.

Although the Purchase and Sale Agreement with ANGD, LLC for the sale of the capital stock of Bluefield Gas provides for a sales price substantially equal to the book value of Bluefield s net assets on the date of closing, the underlying tax basis that Resources has in the stock is significantly less than the book basis. This lower tax basis has resulted in the recording of an estimated income tax expense attributable to the anticipated taxable gain for the excess of the book basis of the assets over the tax basis. The current estimate of tax liability expected to be realized on this transaction is reflected as part of income tax expense in discontinued operations.

Bluefield Gas and the Bluefield division of Roanoke Gas Company (Bluefield Operations) represent approximately 4,600 of Resources 60,000 customers and approximately $12,800,000 of the consolidated assets and $7,600,000 of the consolidated liabilities of the Company as of September 30, 2007 as reflected below. The sale of the Bluefield Operations closed effective as of October 31, 2007.

The Board of Directors approved the Purchase and Sale Agreements of Bluefield Gas and the Bluefield division of Roanoke Gas Company for several reasons. The management time and effort required to oversee Bluefield operations were significantly disproportionate to the size of these operations. The regulatory environment in West Virginia has historically hindered the ability to recover increasing expenses on a timely basis resulting in net losses from those operations in each of the last four fiscal years. The economic conditions in southern West Virginia have led to a loss of population and gas customers in the West Virginia service area. Management believes that the net proceeds realized from these transactions can be reinvested in the Roanoke Gas operations and ultimately provide a better return for the Company than could be realized in the Bluefield operations.

The Company received regulatory approvals from the respective regulatory commissions in Virginia and West Virginia prior to the end of the Company s fiscal year. The operations of both Bluefield Gas and Bluefield Division of Roanoke Gas Company were classified as discontinued operations in accordance with the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, as the pending sale met the probable definition requirement. Both transactions closed on November 2, 2007 with an effective date of October 31, 2007.

In July 2006, the Company entered into an asset purchase and sale agreement for the sale of the assets relating to its Highland Energy gas marketing business. The assets sold included the gas supply contracts between Highland Energy and its customers and related business records. The operations associated with the energy marketing business were reclassified as Discontinued Operations in accordance with the provisions of SFAS No. 144. Under the agreement, a portion of the purchase price was deferred as realization of those revenues was subject to certain provisions. The Company met substantially all of the provisions of the agreement and recorded $160,162 gain on sale of assets in final settlement of the sales contract as part of discontinued operations in 2007.

In June 2005, the Company sold 10 parcels of real estate consisting of bulk propane storage facilities and office space owned by Diversified Energy Company. These properties were originally part of the propane operations that were sold to Inergy Propane, LLC (Inergy) in 2004, but were retained and leased to Inergy with an option to purchase. Inergy exercised its option to purchase all properties in 2005 and the corresponding rental activities and gain on sale of the real estate were recorded in discontinued operations for that period.

The activities associated with the Bluefield Operations, Highland Energy and the real estate operations are included in discontinued operations and are summarized as follows:

	Years Ended September 30		
	2007	2006	2005
Bluefield Operations			
Total Revenues	$ 11,229,432	$ 13,206,878	$ 11,475,831
Pretax Operating Loss	(134,650)	(181,671)	(279,258)
Continuing Costs	773,304	732,007	684,987
Income Tax Expense	(745,598)	(237,544)	(174,887)
Discontinued Operations	$ (106,944)	$ 312,792	$ 230,842
Highland Energy			
Revenues	$	$ 21,962,564	$ 21,571,120
Gain on Sale of Assets	160,162	233,216	
Pretax Operating Income	77,560	98,743	331,420
Continuing Costs		49,992	55,928
Income Tax Expense	(90,238)	(145,014)	(147,055)
Discontinued Operations	$ 147,484	$ 236,937	$ 240,293
Real Estate			
Revenues	$	$	$ 39,366
Gain on Sale of Assets			153,147
Pretax Operating Income			39,366
Continuing Costs			
Income Tax Expense			(73,540)
Discontinued Operations	$	$	$ 118,973
Total			
Revenues	$ 11,229,432	$ 35,169,442	$ 33,086,317
Gain on Sale of Assets	160,162	233,216	153,147
Pretax Operating Income (Loss)	(57,090)	(82,928)	91,528
Continuing Costs	773,304	781,999	740,915
Income Tax Expense	(835,836)	(382,558)	(395,482)
Discontinued Operations	$ 40,540	$ 549,729	$ 590,108

The carrying amounts of the major classes of assets and liabilities subject to the purchase agreements at September 30, 2007 and 2006 are as follows:

	September 30	
	2007	2006
Assets:		
Accounts receivable, net	$ 429,582	$ 658,551
Gas in storage	3,230,624	3,399,639
Other current assets	90,913	619,862
Net utility plant	9,018,903	8,962,113
Other assets	55,322	86,626
Assets available for sale	$ 12,825,344	$ 13,726,791
Liabilities:		
Accounts payable and customer credit balances	$ 1,499,604	$ 1,499,143
Accrued expenses	99,821	217,054
Other current liabilities	4,800,048	3,442,251
Non-current liabilities	1,159,132	3,094,015
Liabilities of assets available for sale	$ 7,558,605	$ 8,252,463

The purchase agreements related to the sale of the Bluefield Operations provide, at Closing for a services agreement to be executed whereby Resources and Roanoke will provide certain customer billing, gas control, regulatory and other administrative services for Bluefield and Appalachian on mutually agreeable terms.

3. ALLOWANCE FOR DOUBTFUL ACCOUNTS

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

	Years Ended September 30		
	2007	2006	2005
Balances, beginning of year	$ 26,584	$ 73,725	$ 25,866
Provision for doubtful accounts	120,671	354,947	282,313
Recoveries of accounts written off	294,887	213,503	264,825
Accounts written off	(395,432)	(615,591)	(499,279)
Balances, end of year	$ 46,710	$ 26,584	$ 73,725

The amounts above are exclusive of the Bluefield operations.

4. BORROWINGS UNDER LINES-OF-CREDIT

The Company has available unsecured lines-of-credit with a bank which will expire March 31, 2008. 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 expenditures 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, 2007	$ 17,000,000
November 16, 2007	21,000,000
February 16, 2008	16,000,000

A summary of the lines-of-credit follows:

	2007	2006	2005
Lines-of-credit at year-end	$ 17,000,000	$ 20,000,000	$ 20,000,000
Outstanding balance at year-end	4,808,000	3,353,000	4,025,000
Highest month-end balances outstanding	8,421,000	17,827,000	14,016,000
Average month-end balances	2,715,000	6,565,000	6,334,000
Average rates of interest during year	5.83%	4.86%	2.94%
Average rates of interest on balances outstanding at year-end	5.62%	5.82%	4.36%

5. LONG-TERM DEBT

Long-term debt consists of the following:

	September 30 2007	2006
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 (5.13% at September 30, 2007) plus 69 basis point spread, with provision for retirement on December 1, 2010	15,000,000	15,000,000
Total long-term debt	28,000,000	28,000,000
Less current maturities	(5,000,000)	
Total long-term debt excluding current maturities	$ 23,000,000	$ 28,000,000

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, 2007 and 2006. At September 30, 2007, approximately $12,283,000 of retained earnings were available for dividends.

The First Mortgage notes are secured by the Company s land and buildings.

The aggregate annual maturities of long-term debt, subsequent to September 30, 2007, are as follows:

Years Ended **September 30**	**Maturities**
2008	$ 5,000,000
2009	
2010	
2011	15,000,000
2012	
Thereafter	8,000,000
Total	$ 28,000,000

6. INCOME TAXES

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

	Years Ended September 30		
	2007	**2006**	**2005**
Current income taxes:			
Federal	$ 806,956	$ 1,448,286	$ 1,491,928
State	113,461	232,491	301,527
Total current income taxes	920,417	1,680,777	1,793,455
Deferred income taxes:			
Federal	1,100,072	8,990	(16,384)
State	246,407	44,929	(26,058)
Total deferred income taxes	1,346,479	53,919	(42,442)
Amortization of investment tax credits	(30,488)	(32,281)	(33,168)
Total income tax expense	$ 2,236,408	$ 1,702,415	$ 1,717,845

Income tax expense for the years ended September 30, 2007, 2006 and 2005 differed from amounts computed by applying the U.S. Federal income tax rate of 34 percent to earnings before income taxes as a result of the following:

	Years Ended September 30		
	2007	**2006**	**2005**
Income before income taxes	$ 6,002,077	$ 4,664,217	$ 4,634,643
Income tax expense computed at the federal statutory rate	$ 2,040,706	$ 1,585,834	$ 1,575,779
Increase (reduction) in income tax expense resulting from:			
State income taxes, net of federal income tax benefit	237,513	183,097	181,810
Amortization of investment tax credits	(30,488)	(32,281)	(33,168)
Other net	(11,323)	(34,235)	(6,576)
Total income tax expense	$ 2,236,408	$ 1,702,415	$ 1,717,845

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

	September 30	
	2007	**2006**
Deferred tax assets:		
Allowance for uncollectibles	$ 18,838	$ 73,197
Accrued pension and post-retirement medical benefits	1,454,905	1,282,947
Accrued vacation	187,173	184,857
Over recovery of gas costs	215,346	1,364,433
Costs of gas held in storage	853,169	825,850
Deferred compensation	338,891	258,231
Other	202,170	126,199
Total deferred tax assets	3,270,492	4,115,714
Deferred tax liabilities:		
Utility plant	7,054,425	6,759,555
Accrued gas costs	51,630	53,357
Sale of Bluefield Gas stock	605,838	
Total deferred tax liabilities	7,711,893	6,812,912
Net deferred tax liability	$ 4,441,401	$ 2,697,198

7. EMPLOYEE BENEFIT PLANS

The Company sponsors both a defined benefit plan and a postretirement benefit 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.

On September 30, 2007, the Company adopted SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*, *an amendment of FASB Statements No. 87, 88, 106 and 132R* (SFAS No. 158). This Standard retains the previous periodic expense calculation on an actuarial basis under the provisions of SFAS No. 87, *Employers Accounting for Pensions* and SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions*. In addition, this statement also requires an employer to recognize the overfunded or underfunded status of defined benefit pensions and other postretirement plans as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. For pension plans, the benefit obligation is the projected benefit obligation, and for other postretirement plans, the benefit obligation is the accumulated benefit obligation. The Company established a regulatory asset for the portion of the obligation expected to be recovered in rates in future periods in accordance with SFAS No. 71. The portion of the obligation attributable to the unregulated operations of the holding company parent is recognized in comprehensive income. SFAS No. 158 also requires an employer to measure the funded status of each plan as of the Company s fiscal year end for fiscal years ending after December 31, 2008. The Company currently uses a June 30 measurement date for its benefit plans.

The following table summarizes the effect of the adoptions of SFAS No. 158 on the Company s financial statements as of September 30, 2007:

	Before Application of SFAS No. 158	Effect of SFAS No. 158	After Application of SFAS No. 158
Regulatory assets	$	$ 1,906,068	$ 1,906,068
Benefit liabilities	1,268,764	2,586,528	3,855,292
Accumulated other comprehensive loss, net of tax		(421,885)	(421,885)

The following tables set forth the benefit obligation, 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		Postretirement Benefits	
	2007	2006	2007	2006
Accumulated benefit obligation	$ 9,364,621	$ 9,106,162	$ 8,427,326	$ 8,266,411
Change in projected benefit obligation:				
Benefit obligation at beginning of year	$ 12,102,103	$ 13,488,753	$ 8,266,411	$ 9,612,853
Service cost	404,909	477,279	147,693	164,539
Interest cost	740,918	695,593	501,838	481,368
Participant contributions			44,042	49,675
Plan amendments				(343,313)
Actuarial gain	(307,353)	(2,102,764)	(113,471)	(1,193,081)
Benefit payments	(402,277)	(456,758)	(419,187)	(505,630)
Benefit obligation at end of year	$ 12,538,300	$ 12,102,103	$ 8,427,326	$ 8,266,411
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 9,248,810	$ 8,424,279	$ 4,212,556	$ 3,586,307
Actual return on plan assets	1,312,622	506,289	624,768	245,374
Employer contributions	825,000	775,000	770,000	896,830
Participant contributions			44,042	49,675
Tax payments			(30,000)	(60,000)
Benefit payments	(402,277)	(456,758)	(419,187)	(505,630)
Fair value of plan assets at end of year	$ 10,984,155	$ 9,248,810	$ 5,202,179	$ 4,212,556
Reconciliation of funded status:				
Funded status	$ (1,554,145)	$ (2,853,293)	$ (3,225,147)	$ (4,053,855)
Unrecognized actuarial gain	N/A	1,986,054	N/A	947,260
Unrecognized transition obligation	N/A		N/A	1,322,246
Contributions made between the measurement date and fiscal year-end	200,000	225,000	724,000	770,000
Net amount recognized	$ (1,354,145)	$ (642,239)	$ (2,501,147)	$ (1,014,349)
Amounts recognized in the balance sheets consist of:				
Noncurrent liabilities	$ (1,354,145)		$ (2,501,147)	
Amounts recognized in accumulated other comprehensive loss:				
Transition obligation, net of tax	$		$ 175,671	
Net actuarial loss, net of tax	160,387		85,827	
Total amounts included in other comprehensive loss, net of tax	$ 160,387		$ 261,498	

The Company established regulatory assets of $726,454 and $1,179,614 as of September 30, 2007 for the portion of the pension and postretirement obligations to be recovered through rates in future periods in accordance with SFAS No. 71.

The Company is amortizing the unrecognized transition obligation over a remaining life of 6 years and projects approximately $29,000 of other comprehensive loss to be recognized as a component of net periodic benefit cost for the year ended September 30, 2008.

The following table details the actuarial assumptions used in determining the projected benefit obligations and net benefit cost of the pension and the accumulated benefit obligations and net benefit cost of the postretirement plan for 2007, 2006 and 2005:

	Pension Benefits			**Postretirement Benefits**		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
Assumptions related to benefit obligations:						
Discount rate	6.25%	6.25%	5.25%	6.25%	6.25%	5.25%
Expected rate of compensation increase	5.00%	5.00%	5.00%	N/A	N/A	N/A
Assumptions related to benefit costs:						
Discount rate	6.25%	5.25%	6.25%	6.25%	5.25%	6.25%
Expected long-term rate of return on plan assets	7.50%	7.50%	7.50%	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**		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
Components of net periodic pension cost:						
Service cost	$ 404,909	$ 477,279	$ 327,424	$ 147,693	$ 164,539	$ 128,972
Interest cost	740,918	695,593	631,731	501,838	481,368	444,267
Expected return on plan assets	(691,262)	(628,273)	(571,881)	(238,896)	(215,026)	(185,810)
Amortization of unrecognized transition obligation				188,892	200,994	237,300
Recognized loss	72,225	240,307	62,395	9,887	78,969	
Net periodic benefit cost	$ 526,790	$ 784,906	$ 449,669	$ 609,414	$ 710,844	$ 624,729

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) of 9%, 10%, and 9% for 2007, 2006 and 2005, respectively. The rates were assumed to decrease gradually to 5% by 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:

	1% Point Increase	1% Point Decrease
Effect on total service and interest cost components	$ 94,808	$ (77,294)
Effect on accumulated postretirement benefit obligation	1,008,371	(836,137)

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	2007	2006	Target	2007	2006
Asset category:						
Equity securities	50%-70%	60%	61%	35%-65%	51%	50%
Debt securities	30%-50%	34%	36%	35%-65%	41%	42%
Other	0%-20%	6%	3%	0%-20%	8%	8%

The primary objectives of the Company s investment policy 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 $600,000 to its postretirement benefit plan in 2008.

The following table reflects expected future benefit payments.

Fiscal year ending September 30	Pension Plan	Postretirement Benefit Plan
2008	$ 410,000	$ 490,000
2009	423,000	497,000
2010	435,000	501,000
2011	465,000	512,000
2012	512,000	515,000
2013-2017	3,193,000	2,784,000

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 makes matching contributions to the plan with a 100% match on the participants first 3% of contributions and 50% on the next 3% of contributions. Company matching contributions were $240,946, $233,327 and $229,441 for 2007, 2006 and 2005, 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, 2007, 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 KESOP are as follows:

	Number of Shares	Weighted-Average Price	Option Price Per Share
Options outstanding, September 30, 2004	53,500	$ 19.288	$ 15.500-$ 20.875
Options exercised	(7,500)	$ 17.708	
Options expired			
Options outstanding, September 30, 2005	46,000	$ 19.545	$ 16.875-$ 20.875
Options exercised	(2,000)	$ 20.875	
Options expired			
Options outstanding, September 30, 2006	44,000	$ 19.485	$ 16.875-$ 20.875
Options exercised	(12,500)	$ 19.425	
Options expired			
Options outstanding, September 30, 2007	31,500	$ 19.508	$ 18.100-$ 20.875

	Options Outstanding and Exercisable		
	Shares	Remaining Life (Years)	Exercise Price
	9,000	2.2	$ 20.875
	7,000	3.2	19.250
	9,000	4.2	19.360
	6,500	5.2	18.100
Weighted average	31,500	3.6	$ 19.508

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, 2007 and 2006. No options were granted in 2007, 2006 and 2005. The Company received $242,812 from the exercise of options in 2007.

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 28,490, 29,721 and 20,349 shares in 2007, 2006 and 2005, respectively. As of September 30, 2007, the Company had 287,401 shares available for issuance under this plan.

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. 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 4,091 shares of Restricted Stock in fiscal 2007, representing $84,550 in compensation and $25,013 in dividends reinvested. The directors also received 4,038 shares of Restricted Stock in fiscal 2006, representing $83,080 in compensation and $19,662 in dividends reinvested and 3,366 shares of Restricted Stock in fiscal 2005, representing $68,601 in compensation and $18,770 in dividends reinvested. As of September 30, 2007, the Company had 19,720 shares available for issuance under this plan.

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 amount of their annual salary. To promote this policy, the Plan provides that all officers with stock ownership positions below 50% 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 2,462, 3,899 and 2,314 shares valued at $68,573, $101,438 and $61,895, respectively, in 2007, 2006 and 2005. As of September 30, 2007, the Company had 23,779 shares available for issuance under this plan.

10. ENVIRONMENTAL MATTER

Both Roanoke Gas and Bluefield Gas, subsidiaries of RGC Resources, Inc., operated manufactured gas plants (MGPs) as a source of fuel for lighting and heating until the late 1940s or early 1950s. 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 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 right of Bluefield Gas to defer MGP clean-up costs, should any be incurred, and to seek rate recovery for such costs. While the Company is selling the stock of Bluefield Gas to ANGD, it has retained ownership of the former MPG site, and entered into an Indemnification and Cost Sharing Agreement with ANGD and Bluefield Gas concerning the site that requires Bluefield Gas and ANGD to seek recovery of any environmental remediation costs through rate recovery and under any applicable insurance policies or from any third party and to reimburse the Company for 25% of any such costs to the extent they are not otherwise recovered. If the Company eventually incurs costs associated with a required clean-up of the Roanoke Gas 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.

11. 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 under asset management contracts. The Company uses an asset manager to assist in optimizing the use of its transportation, storage rights, and gas supply inventories to provide a 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, 2007. 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 table reflects the financial and volumetric obligations as of September 30, 2007 for each of the years presented for Roanoke Gas. The table does not include the contracts related to the discontinued operations of Bluefield Gas.

Fiscal Year Ending September 30,	Fixed Price Contracts Pipeline and Storage Capacity	Market Price Contracts Natural Gas Contracts (Decatherms)
2008	$ 9,729,451	285,985
2009	9,729,451	
2010	9,729,451	
2011	9,729,451	
2012	9,729,451	

The Company purchased approximately $60,121,000 in gas under the asset management contracts in fiscal 2007.

Subsequent to September 30, 2007, the Company executed a new asset management agreement effective November 1, 2007. The new three-year asset management agreement will result in additional volumetric obligations of 1,907,195; 2,225,059; 2,225,059 and 317,864 decatherms for fiscal 2008, 2009, 2010 and 2011, respectively.

The Company has historically entered into derivative financial contracts for the purpose of hedging the price of natural gas. As of September 30, 2007, the Company has contracted to hedge a set amount of decatherms of natural gas for each month in the winter period, totaling 680,000 decatherms. All decatherm amounts have a ceiling price of $9.90 per decatherm and floor prices ranging from $5.30 to $7.95 per decatherm; see *Derivative and Hedging Activities* section in footnote 1 for more information.

12. 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, 2007 and 2006 are as follows:

	2007		2006	
	Carrying Amounts	Approximate Fair Value	Carrying Amounts	Approximate Fair Value
Long-term debt	$ 28,000,000	$ 28,934,541	$ 28,000,000	$ 29,009,682

Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of September 30, 2007 and 2006 are not necessarily indicative of the amounts the Company could have realized in market exchanges.

13. 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 purging and capping its distribution mains and services upon retirement, although the timing of such retirements is uncertain. The Company recorded a conditional asset retirement obligation of $2,499,345 and $2,404,839 pursuant to its legal obligations upon retirement of its distribution pipeline system as of September 30, 2007 and 2006, 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.

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Quarterly financial data for the years ended September 30, 2007 and 2006 is summarized as follows:

2007	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Operating revenues	$ 26,417,644	$ 37,572,113	$ 15,131,375	$ 10,780,169
Gross margin	$ 7,243,434	$ 8,540,116	$ 4,947,278	$ 4,490,948
Operating income	$ 2,962,789	$ 4,167,463	$ 764,884	$ 63,143
Net income (loss) from continuing operations	$ 1,511,653	$ 2,286,035	$ 236,520	$ (268,539)
Net income (loss) from discontinued operations	$ 173,862	$ 306,669	$ (459,586)	$ 19,595
Net income (loss)	$ 1,685,515	$ 2,592,704	$ (223,066)	$ (248,944)
Basic earnings (loss) per share				
Continuing operations	$ 0.70	$ 1.06	$ 0.11	$ (0.13)
Discontinued operations	$ 0.08	$ 0.14	$ (0.21)	$ 0.01
Net income (loss)	$ 0.78	$ 1.20	$ (0.10)	$ (0.12)

2006	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenues	$ 38,384,131	$ 33,488,422	$ 11,495,048	$ 11,223,271
Gross margin	$ 6,618,623	$ 7,778,537	$ 4,387,464	$ 4,223,648
Operating income	$ 2,511,910	$ 3,493,431	$ 457,497	$ 214,662
Net income (loss) from continuing operations	$ 1,211,167	$ 1,817,998	$ 26,127	$ (93,490)
Net income (loss) from discontinued operations	$ 241,015	$ 339,076	$ (83,086)	$ 52,724
Net income (loss)	$ 1,452,182	$ 2,157,074	$ (56,959)	$ (40,766)
Basic earnings (loss) per share				
Continuing operations	$ 0.58	$ 0.86	$ 0.01	$ (0.05)
Discontinued operations	$ 0.11	$ 0.16	$ (0.04)	$ 0.03
Net income (loss)	$ 0.69	$ 1.02	$ (0.03)	$ (0.02)

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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