FORM 10-K

Annual report pursuant to section 13 and 15(d)

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FILER

DELTA NATURAL GAS CO INC

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SIC: **4923** Natural gas transmisison & distribution

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

(Mark one)

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

For the fiscal year ended June 30, 2008.

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

For the transition period from _______ to ________

Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

Kentucky	61-0458329
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3617 Lexington Road, Winchester, Kentucky	**40391**
(Address of principal executive offices)	**(Zip code)**

859-744-6171

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock $1 Par Value	NASDAQ OMX Group

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasonal issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or Section 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "accelerated filer, large accelerated filer and smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☒

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recent completed second fiscal quarter. $ 82,978,469

As of August 15, 2008, Delta Natural Gas Company, Inc. had outstanding 3,296,801 shares of common stock $1 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's definitive proxy statement, to be filed with the Commission not later than 120 days after June 30, 2008, is incorporated by reference in Part III of this Report.

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PART I

Item 1. Business

General

We distribute or transport natural gas to approximately 38,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We produce a relatively small amount of natural gas from our southeastern Kentucky wells.

We seek to provide dependable, high-quality service to our customers while steadily enhancing value for our shareholders. Our efforts have been focused on developing a balance of regulated and non-regulated businesses to contribute to our earnings by profitably producing, selling and transporting gas in our service territory.

We strive to achieve operational excellence through economical, reliable service and our emphasis on responsiveness to customers. We continue to invest in facilities for the transmission, distribution and storage of natural gas. We believe that our responsiveness to customers and the dependability of the service we provide afford us additional opportunities for growth. While we seek those opportunities, our strategy will continue a conservative approach that seeks to minimize our exposure to market risk arising from fluctuations in the prices of gas.

We operate through two segments, a regulated segment and a non-regulated segment. See Note 14 of the Notes to Consolidated Financial Statements for a discussion of these segments. Through our regulated segment, we distribute natural gas to our retail customers in 23 predominantly rural counties. In addition, our regulated segment transports gas to industrial customers on our system who purchase gas in the open market. Our regulated segment also transports gas on behalf of local producers and other customers not on our distribution system. Our results of operations and financial condition have been strengthened by regulatory developments in recent years, including a $3,920,000 revenue increase from our last rate case, a weather normalization provision, which has reduced fluctuations in our earnings due to variations in weather, and a gas cost recovery clause, which mitigates market risk arising from fluctuations in the price of gas.

We operate our non-regulated segment through three wholly-owned subsidiaries. Two of these subsidiaries, Delta Resources, Inc. and Delgasco, Inc., purchase natural gas in the open market, including from Kentucky producers. We resell this gas to industrial customers on our distribution system and to others not on our system. Our third subsidiary, Enpro, Inc., produces natural gas that is sold in the open market.

Our executive offices are located at 3617 Lexington Road, Winchester, Kentucky 40391. Our telephone number is (859) 744-6171. Our website is www.deltagas.com.

Distribution and Transmission of Natural Gas

The economy of our service area is based principally on coal mining, farming and light industry. The communities we serve typically contain populations of less than 20,000. Our three largest service areas are Nicholasville, Corbin and Berea, Kentucky. In Nicholasville we serve approximately 8,000 customers, in Corbin we serve approximately 6,000 customers, and in Berea we serve approximately 4,000 customers.

During fiscal 2008 we received an order from the Kentucky Public Service Commission, which granted us an increase in the base rates we charge our customers. The order was the result of a settlement agreement we reached with the Kentucky Attorney General in our rate case. The increased rates are designed to generate an additional $3,920,000 in revenue. The increase in rates helped to offset the impact of declining customer usage due to conservation and efficiency, a trend we have experienced the past several years. Some of the communities we serve continue to expand, resulting in growth opportunities for us. Industrial parks have been developed in our service areas, which could result in additional growth in industrial customers as well.

Factors that affect our revenues include rates we charge our customers, our supply cost for the natural gas we purchase for resale, economic conditions in our service areas, weather and competition.

Although the Kentucky Public Service Commission permits us to pass through to our customers changes in the price we must pay for our gas supply, increases in our rates to customers may cause our customers to conserve or to use alternative energy sources.

Our regulated sales are seasonal and temperature-sensitive, since the majority of the gas we sell is used for heating. Variations in the average temperature during the winter impact our revenues year-to-year. The Kentucky Public Service Commission, through our tariff, permits us to adjust the rates we charge our customers in response to winter weather that is warmer or colder than normal temperatures.

We compete with alternate sources of energy for our regulated distribution customers. These alternate sources include electricity, coal, oil, propane and wood. Our non-regulated subsidiaries, which sell gas to industrial customers and others, compete with natural gas producers and natural gas marketers for those customers.

Our larger customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the gas to their plants or facilities. Customers may undertake such a by-pass of our distribution system in order to achieve lower prices for their gas service. Our larger customers who are in close proximity to alternative supplies would be most likely to consider taking this action. Additionally, some of our industrial customers are able to switch economically to alternative sources of energy. These are competitive concerns that we continue to address.

Some natural gas producers in our service area can access pipeline delivery systems other than ours, which generates competition for our transportation services. We continue our efforts to purchase or transport natural gas that is produced in reasonable proximity to our transportation facilities.

As an active participant in many areas of the natural gas industry, we plan to continue efforts to expand our gas distribution system and customer base. We continue to consider acquisitions of other gas systems, some of which are contiguous to our existing service areas, as well as expansion within our existing service areas.

We anticipate continuing activity in gas production and transportation and plan to pursue and increase these activities wherever practicable. We continue to consider the construction, expansion or acquisition of additional transmission, storage and gathering facilities to provide for increased transportation, enhanced supply and system flexibility.

A single customer, Citizens Gas Utility District, provided $17,087,000, $9,843,000 and $15,422,000 of non-regulated revenues during 2008, 2007 and 2006, respectively, although there is no assurance that revenues from them will continue at these levels. See Note 14 of the Notes to Consolidated Financial Statements.

Gas Supply

We purchase our natural gas from a combination of interstate and Kentucky sources. In our fiscal year ended June 30, 2008, we purchased approximately 99% of our natural gas from interstate sources.

Interstate Gas Supply

We acquire our interstate gas supply from gas marketers. We currently have commodity requirements agreements with Atmos Energy Marketing (“Atmos”) for our Columbia Gas Transmission Corporation (“Columbia Gas”), Columbia Gulf Transmission Corporation (“Columbia Gulf”), Tennessee Gas Pipeline (“Tennessee”) and Texas Eastern Transmission Corporation (“Texas Eastern”) supplied areas. Under these commodity requirements agreements, Atmos is obligated to supply the volumes consumed by our regulated customers in defined sections of our service areas. The gas we purchase under these agreements is priced at index-based market prices or at mutually agreed-to fixed prices. The index-based market prices are determined based on the prices published on the first of the month in Platts’ Inside FERC’s Gas Market Report in the indices that relate to the pipelines through which the gas will be transported, plus or minus an agreed-to fixed price adjustment per million British Thermal Units of gas sold. Consequently, the price we pay for interstate gas is based on current market prices.

Our agreements with Atmos for the Columbia Gas, Columbia Gulf, Tennessee and Texas Eastern supplied service areas continue year to year unless cancelled by either party by written notice at least sixty days prior to the annual anniversary date (April 30) of the agreement.

We also purchase additional interstate natural gas from Atmos, as needed, in addition to our commodity requirements agreements with Atmos. This spot gas purchasing arrangement is pursuant to an agreement with Atmos containing an "evergreen" clause which permits either party to terminate the agreement by providing not less than sixty days written notice. Delta's purchases from Atmos under this spot purchase agreement are generally month-to-month. However, Delta does have the option of forward-pricing gas for one or more months for the upcoming winter season. The price of gas under this agreement is based on current market prices, determined in a similar manner as under the commodity requirements contract with Atmos, with an agreed-to fixed price adjustment per million British Thermal Units purchased. In our fiscal year ended June 30, 2008, approximately 42% of Delta's gas supply was purchased under our agreements with Atmos.

Delta purchases gas from M & B Gas Services, Inc. ("M & B") for injection into our underground natural gas storage field and to supply a portion of our system. We are not obligated to purchase any minimum quantities from M & B nor to purchase gas from M & B for any periods longer than one month at a time. The gas is priced at index-based market prices or at mutually agreed-to fixed prices. Our agreement with M & B may be terminated upon 30 days prior written notice by either party. Any purchase agreements for unregulated sales activities may have longer terms or multiple month purchase commitments. In our fiscal year ended June 30, 2008, approximately 57% of Delta's gas supply was purchased under our agreement with M & B.

We also purchase interstate natural gas from other gas marketers as needed at either current market prices, determined by industry publications, or at forward market prices.

Transportation of Interstate Gas Supply

Our interstate natural gas supply is transported to us from market hubs, production fields and storage fields by Tennessee, Columbia Gas, Columbia Gulf and Texas Eastern.

Our agreements with Tennessee extend through 2013 and thereafter automatically renew for subsequent five-year terms unless terminated by one of the parties. Tennessee is obligated under these agreements to transport up to 19,600 thousand cubic feet ("Mcf") per day for us. During fiscal 2008, Tennessee transported a total of 1,141,000 Mcf for us under these contracts. Annually, approximately 28% of Delta's supply requirements flow through Tennessee to our points of receipt under our transportation agreements with Tennessee. We have gas storage agreements with Tennessee under the terms of which we reserve a defined storage space in Tennessee's storage fields and we reserve the right to withdraw up to fixed daily volumes. These gas storage agreements terminate on the same schedule as our transportation agreements with Tennessee.

Under our agreements with Columbia Gas and Columbia Gulf, Columbia Gas is obligated to transport, including utilization of our defined storage space as required, up to 12,600 Mcf per day for us, and Columbia Gulf is obligated to transport up to a total of 4,300 Mcf per day for us. During fiscal 2008 Columbia Gas and Columbia Gulf transported for us a total of 588,000 Mcf, or approximately 14% of Delta's supply requirements, under all of our agreements with them. All of our transport agreements with Columbia Gas and Columbia Gulf continue on a year-to-year basis until terminated by one of the parties.

Columbia Gulf also transported additional volumes under agreements it has with M & B to a point of interconnection between Columbia Gulf and us where we purchase the gas to inject into our storage field, as discussed above. The amounts transported and sold to us under the agreement between Columbia Gulf and this gas marketer for fiscal 2008 constituted approximately 57% of Delta's gas supply. We are not a party to any of these separate transportation agreements on Columbia Gulf.

We have no direct agreement with Texas Eastern. However, Atmos has an arrangement with Texas Eastern to transport the gas to us that we purchase from that marketer to supply our customers' requirements in specific geographic areas. Consequently, Texas Eastern transports a small percentage of our interstate gas supply. In our fiscal year ended June 30, 2008, Texas Eastern transported approximately 17,000 Mcf of natural gas to our system, which constituted less than 1% of our gas supply.

Kentucky Gas Supply

We have an agreement with Chesapeake Appalachia LLC to purchase natural gas on a year-to-year basis unless terminated by one of the parties. We purchased 41,000 Mcf from Chesapeake during fiscal 2008. The price for the gas we purchase from Chesapeake is based on the index price of spot gas delivered to Columbia Gas in the relevant region as reported in Platt's Inside FERC's Gas Market Report, plus a fixed adjustment per million British Thermal units of gas purchased. Chesapeake delivers this gas to our customers directly from its own pipelines.

We own and operate an underground natural gas storage field that we use to store a significant portion of our winter gas supply needs. This storage capability permits us to purchase and store gas during the non-heating months and then withdraw and sell the gas during the peak usage months.

We continue to maintain an active gas supply management program that emphasizes long-term reliability and the pursuit of cost-effective sources of gas for our customers.

Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our regulated natural gas distribution and transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers.

We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. The test year for the case was the twelve months ended December 31, 2006. The increased rates were requested to become effective May 20, 2007, but the implementation of the proposed rates was suspended until October 20, 2007.

During October, 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

The Kentucky Public Service Commission has also approved a gas cost recovery clause, which permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs. Although we are not required to file a general rate case to adjust rates pursuant to the gas cost recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual gas costs were incurred. Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

In July, 2008, the Kentucky Public Service Commission approved in Case No. 2008-00062 our request to implement a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits and promote conservation awareness, and it also provides rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customers by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates will be adjusted annually to recover the costs incurred under these programs, including the reimbursement of margins on lost sales and the incentives provided to us.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in four other cities we serve. In the other cities and areas we serve, either our franchises have expired, the areas served do not have governmental organizations authorized to grant franchises or the city governments do not require a franchise. We attempt to acquire or reacquire franchises whenever feasible.

Without a franchise, a city could require us to cease our occupation of the streets and public grounds or prohibit us from extending our facilities into any new area of that city. To date, the absence of a franchise has caused no adverse effect on our operations.

Capital Expenditures

Capital expenditures during 2008 were $5.6 million and for 2009 are estimated to be $7.9 million. Our expenditures include system extensions as well as the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities.

Financing

Our capital expenditures and operating cash requirements are met through the use of internally generated funds and a short-term bank line of credit. The current available line of credit is $40 million, of which $6.8 million was borrowed at June 30, 2008.

Present plans are to continue to utilize the short-term bank line of credit to help meet planned capital expenditures and operating cash requirements. The amounts and types of future long-term debt and equity financings will depend upon our capital needs and market conditions.

Employees

On June 30, 2008, we had 158 full-time employees. We consider our relationship with our employees to be satisfactory. Our employees are not represented by unions nor are they subject to any collective bargaining agreements.

Available Information

We make available free of charge on our Internet website http://www.deltagas.com, our Business Code of Conduct and Ethics, annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC also maintains an internet site http://www.sec.gov that contains reports, proxy and information statements and other information regarding Delta. The public may read and copy any materials the Company files with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The SEC phone number is 1-800-732-0330.

Consolidated Statistics

For the Years Ended June 30,	**2008**	2007	2006	2005	2004
Average Retail Customers Served					
Residential	**31,520**	31,941	32,601	33,284	33,570
Commercial	**5,107**	5,128	5,154	5,241	5,298
Industrial	**54**	59	59	60	61
Total	**36,681**	37,128	37,814	38,585	38,929
Operating Revenues ($000) (a)					
Residential sales	**30,742**	28,648	35,240	29,172	28,737
Commercial sales	**21,171**	19,339	24,081	18,029	18,719
Industrial sales	**1,707**	1,676	2,356	1,744	1,731
Total regulated sales (b)(c)	**53,620**	49,663	61,677	48,945	49,187
On-system transportation (c)	**4,461**	4,258	4,371	4,312	3,854
Off-system transportation (c)	**3,864**	2,979	2,543	2,099	2,104
Non-regulated sales	**54,438**	44,669	51,904	31,971	27,091
Other	**293**	242	250	211	205
Eliminations for intersegment	**(4,019)**	(3,643)	(3,498)	(3,357)	(3,247)
Total	**112,657**	98,168	117,247	84,181	79,194
System Throughput (Million Cu. Ft.) (a)					
Residential sales	**1,695**	1,801	1,764	2,018	2,202
Commercial sales	**1,286**	1,345	1,313	1,381	1,529
Industrial sales	**121**	136	146	158	164
Total regulated sales (b)	**3,102**	3,282	3,223	3,557	3,895
On-system transportation	**4,975**	5,161	5,322	5,273	5,166
Off-system transportation	**12,623**	9,774	8,789	7,194	7,190
Non-regulated sales	**5,394**	4,921	4,398	3,924	3,958
Eliminations for intersegment	**(5,276)**	(4,822)	(4,313)	(3,831)	(3,918)
Total	**20,818**	18,316	17,419	16,117	16,291
Average Annual Consumption Per Average Residential Customer (Thousand Cu. Ft.)	**54**	56	54	61	66
Lexington, Kentucky Degree Days					
Actual	**4,464**	4,419	4,309	4,293	4,493
Percent of 30 year average	**96**	95	92	92	96

(a) Additional financial information related to our segments can be found in Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 14 of the Notes to Consolidated Financial Statements.

(b) 2005 regulated sales includes a $1,246,000 non-recurring increase in revenues due to the recording of 58,000 Mcf of unbilled sales at June 30, 2005.

(c) We implemented new regulated base rates as approved by the Kentucky Public Service Commission in October, 2007 and October, 2004, and the base rates were designed to generate additional annual revenue of $3,920,000 and $2,756,000, respectively.

Item 1A. Risk Factors

The risk factors below should be carefully considered.

WEATHER CONDITIONS MAY CAUSE OUR REVENUES TO VARY FROM YEAR TO YEAR. Our revenues vary from year to year, depending on weather conditions. We estimate that approximately 76% of our annual gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell in any year, which would reduce our revenues and profits. Our weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, only partially mitigates this risk. We adjust our rates to residential and small non-residential customers to reflect variations from thirty-year average weather for our December through April billing cycles.

CHANGES IN FEDERAL REGULATIONS COULD REDUCE THE AVAILABILITY OR INCREASE THE COST OF OUR INTERSTATE GAS SUPPLY. We purchase almost all of our gas supply from interstate sources. For example, in our fiscal year ended June 30, 2008, approximately 99% of our gas supply was purchased from interstate sources. The Federal Energy Regulatory Commission regulates the transmission of the natural gas we receive from interstate sources, and it could increase our transportation costs or decrease our available pipeline capacity by changing its regulatory policies in a manner that could increase transportation rates or reduce pipeline or storage capacity available to us.

OUR GAS SUPPLY DEPENDS UPON THE AVAILABILITY OF ADEQUATE PIPELINE TRANSPORTATION CAPACITY. We purchase almost all of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation service could reduce our normal interstate supply of gas.

OUR CUSTOMERS ARE ABLE TO ACQUIRE NATURAL GAS WITHOUT USING OUR DISTRIBUTION SYSTEM. Our larger customers can obtain their natural gas supply by purchasing their natural gas directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the gas to their plants or facilities. Customers may undertake such a by-pass of our distribution system in order to achieve lower prices for their gas service. Our larger customers who are in close proximity to alternative supply would be most likely to consider taking this action. This potential to by-pass our distribution system creates a risk of the loss of large customers and thus could result in lower revenues and profits.

WE FACE REGULATORY UNCERTAINTY AT THE STATE LEVEL. We are regulated by the Kentucky Public Service Commission. Our regulated segment generates a significant portion of our income from operations. We face the risk that the Kentucky Public Service Commission may fail to grant us adequate and timely rate increases or may take other actions that would cause a reduction in our income from operations, such as limiting our ability to pass on to our customers our increased costs of natural gas. Such regulatory actions would decrease our revenues and our profitability.

VOLATILITY IN THE PRICE OF NATURAL GAS COULD REDUCE OUR PROFITS. Significant increases in the price of natural gas will likely cause our regulated retail customers to continue to conserve or switch to alternate sources of energy. Any decrease in the volume of gas we sell that is caused by such actions will reduce our revenues and profits. Higher prices also make it more difficult to add new customers. Significant decreases in the price of natural gas will likely cause our non-regulated segment margins to decrease.

WE HAVE NOT HISTORICALLY GENERATED SUFFICIENT CASH FLOWS TO MEET ALL OUR CASH NEEDS. We have made capital expenditures in order to maintain, expand and upgrade our distribution and transmission system. As a result, we have funded a portion of our cash needs through borrowing and by offering new securities into the market. For example, by a combination of increasing our borrowings under our short-term bank line of credit and sales of securities through our dividend reinvestment plan, we generated cash in the amount of $3,116,000 in fiscal 2008. In 2007 cash provided by operating activities was sufficient to meet our financing needs, and we were able to make a net repayment on our short-term bank line of credit in the amount of $2,856,000. Although cash needs vary from year to year, our dependence on external sources of financing creates the risks that our profits could decrease as a result of high capital costs and that lenders could impose onerous and unfavorable terms on us as a condition to granting us loans. We also have the risk that we may not be able to secure external sources of cash necessary to fund our operations.

SUBSTANTIAL OPERATIONAL RISKS ARE INVOLVED IN OPERATING A NATURAL GAS DISTRIBUTION, PIPELINE AND STORAGE SYSTEM AND SUCH OPERATIONAL RISKS COULD REDUCE OUR REVENUES AND INCREASE EXPENSES. There are substantial risks associated with the operation of a natural gas distribution, pipeline and storage system, such as operational hazards and unforeseen interruptions caused by events beyond our control. These include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of pipeline facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, floods, landslides or other similar events beyond our control. These risks could result in injury or loss of life, extensive property damage and environmental pollution, which in turn could lead to substantial financial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks. Liabilities incurred that are not fully covered by insurance could adversely affect our results of operations and financial condition. Additionally, interruptions to the operation of our gas distribution, transmission or storage system caused by such an event could reduce our revenues and increase our expenses.

HURRICANES OR OTHER EXTREME WEATHER COULD INTERRUPT OUR GAS SUPPLY AND INCREASE NATURAL GAS PRICES. Hurricanes or other extreme weather could damage production or transportation facilities, which could result in decreased supplies of natural gas and increased supply costs for us and higher prices for our customers.

CROSS-DEFAULT PROVISIONS IN OUR BORROWING ARRANGEMENTS INCREASE THE CONSEQUENCES OF A DEFAULT ON OUR PART. Each indenture under which our outstanding debt has been issued, and the loan agreement for our bank line of credit, contains a cross-default provision which provides that we will be in default under such indenture or loan agreement in the event of certain defaults under any of the other indentures or loan agreement. Accordingly, should an event of default occur under one of our debt agreements, we face the prospect of being in default under all of our debt agreements and obliged in such instance to satisfy all of our then-outstanding indebtedness. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us.

OUR BORROWING ARRANGEMENTS INCLUDE VARIOUS NEGATIVE COVENANTS THAT RESTRICT OUR ACTIVITIES.

Without bank approval or repaying the bank line of credit, our bank line of credit restricts us from:

- merging with another entity,
- selling a material portion of our assets other than in the ordinary course of business,
- issuing stock which in the aggregate exceeds thirty-five percent (35%) of our outstanding shares of common stock, and
- having any person hold more than twenty percent (20%) of our outstanding shares of common stock.

Our 7.00% Debentures and 5.75% Insured Quarterly Notes restrict us from:

- assuming additional mortgage indebtedness in excess of $5,000,000, and
- paying dividends on our common stock unless our consolidated shareholders' equity minus the value of our intangible assets exceed $25,800,000.

These negative covenants create the risk that we may be unable to take advantage of business and financing opportunities as they arise.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We own our corporate headquarters in Winchester, Kentucky. We own ten buildings used for field operations in the cities we serve. Also, we own a building in Laurel County, Kentucky used for training and equipment and materials storage.

We own approximately 2,500 miles of natural gas gathering, transmission, distribution, storage and service lines. These lines range in size up to twelve inches in diameter.

We hold leases for the storage of natural gas under 8,000 acres located in Bell County, Kentucky. We developed this property for the underground storage of natural gas.

We use all the properties described in the three paragraphs immediately above principally in connection with our regulated natural gas distribution, transmission and storage segment. See Note 14 of the Notes to Consolidated Financial Statements for a description of Delta's two business segments.

Through our wholly-owned subsidiary, Enpro, we produce natural gas as part of the non-regulated segment of our business.

Enpro owns interests in oil and natural gas leases on 10,300 acres located in Bell, Knox and Whitley Counties. Thirty-five gas wells are producing from these properties. The remaining proved, developed natural gas reserves on these properties are estimated at 2.8 million Mcf. Also, Enpro owns the natural gas underlying 15,400 additional acres in Bell, Clay and Knox Counties. These properties have been leased to others and are currently being developed. We have performed no reserve studies on these properties. Enpro produced a total of 162,000 Mcf of natural gas during fiscal 2008 from all the properties described in this paragraph.

A producer is conducting exploration activities on part of Enpro's developed holdings. Enpro reserved the option to participate in wells drilled by this producer and also retained certain working and royalty interests in any production from future wells.

Our assets have no significant encumbrances.

Item 3. Legal Proceedings

We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

Item 4. Submission of Matters to a Vote of Security Holders

No matter was submitted during the fourth quarter of 2008.

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

We have paid cash dividends on our common stock each year since 1964. The frequency and amount of future dividends will depend upon our earnings, financial requirements and other relevant factors, including limitations imposed by the indenture for our Insured Quarterly Notes and Debentures (as described in Note 9 of the Notes to Consolidated Financial Statements).

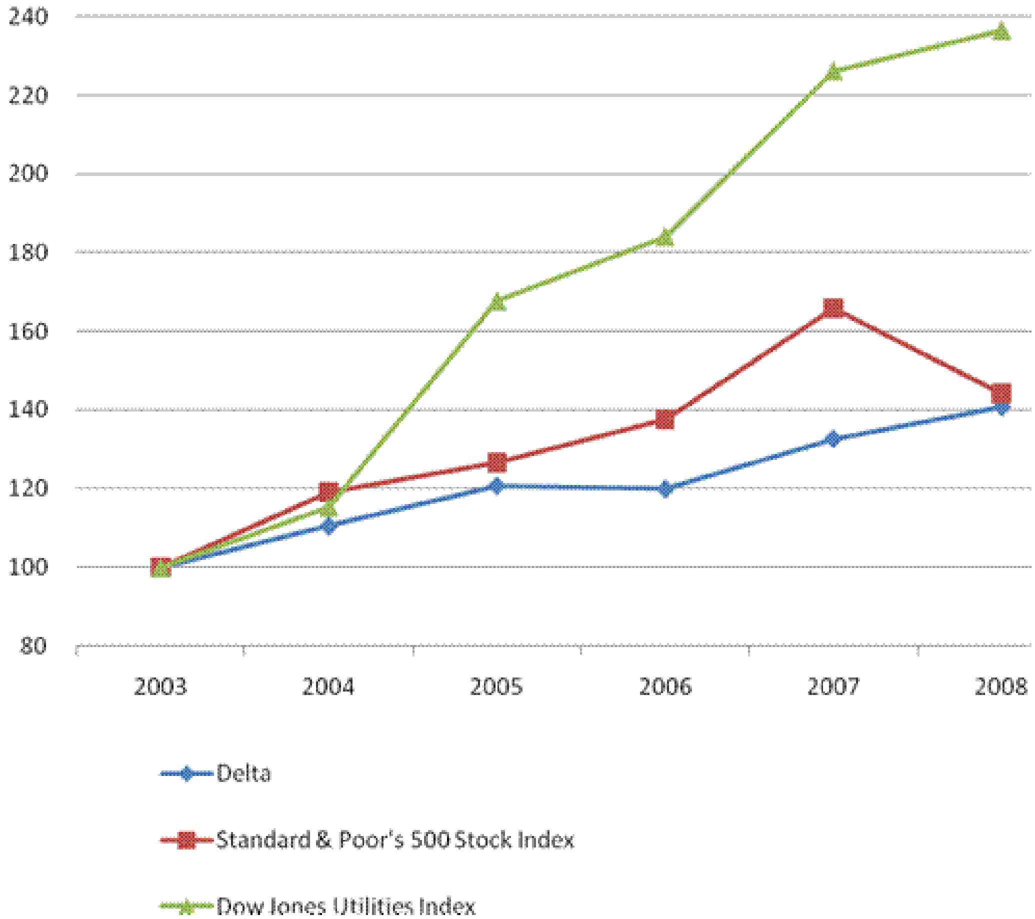
Our common stock is traded on the NASDAQ OMX Group and trades under the symbol "DGAS". There were 1,837 record holders of our common stock as of August 15, 2008. The accompanying table sets forth, for the periods indicated, the high and low sales prices for the common stock on the NASDAQ OMX Group and the cash dividends declared per share.

	Range of Stock Prices ($)		Dividends
	High	Low	Per Share ($)
Quarter			
Fiscal 2008			
First	**25.83**	**23.50**	**.31**
Second	**25.84**	**24.10**	**.31**
Third	**26.73**	**24.11**	**.31**
Fourth	**32.19**	**24.25**	**.31**
Fiscal 2007			
First	25.50	24.11	.305
Second	25.60	24.50	.305
Third	25.48	24.30	.305
Fourth	26.08	23.89	.305

The closing sale prices shown above reflect prices between dealers and do not include markups or markdowns or commissions and may not necessarily represent actual transactions.

Comparison of Five-Year Cumulative Total Shareholder Return

The following graph sets forth a comparison of five year cumulative total shareholder return (equal to dividends plus stock price appreciation) among our common shares, the Standard & Poor's 500 Stock Index and the Dow Jones Utilities Index during the past five fiscal years. Information reflected on the graph assumes an investment of $100 on June 30, 2003 in each of our common shares, the Standard & Poor's Stock Index and the Dow Jones Utilities Index. Cumulative total return assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns.



	2003	2004	2005	2006	2007	2008
Delta	100.0	110.5	120.6	119.9	132.6	140.7
Standard & Poor's 500 Stock Index	100.0	119.1	126.6	137.6	165.9	144.1
Dow Jones Utilities Index	100.0	115.4	167.8	184.0	226.1	236.4

Item 6. Selected Financial Data

For the Years Ended June 30,	**2008**	2007	2006	2005	2004
Summary of Operations ($)					
Operating revenues (a)(b)	**112,657,117**	98,168,391	117,247,144	84,181,233	79,193,614
Operating income (a)(b)	**15,663,736**	12,968,043	12,757,507	12,490,127	10,532,904
Net income (a)(b)	**6,829,868**	5,298,347	5,024,635	4,998,619	3,838,059
Basic and diluted earnings per common share (a)(b)	**2.08**	1.62	1.55	1.55	1.20
Cash dividends declared per common share	**1.24**	1.22	1.20	1.18	1.18
Weighted Average Number of Common Shares Outstanding (Basic and Diluted)	**3,285,464**	3,265,800	3,242,223	3,216,668	3,185,158
Total Assets ($)	**170,814,856**	160,400,950	155,554,125	144,762,217	138,372,129
Capitalization ($)					
Common shareholders' equity	**57,593,585**	54,428,471	52,609,724	50,799,454	48,830,161
Long-term debt (c)	**58,318,000**	58,625,000	58,790,000	52,707,000	53,049,000
Total capitalization	**115,911,585**	113,053,471	111,399,724	103,506,454	101,879,161
Short-Term Debt ($)(c)(d)	**8,028,791**	5,389,918	8,246,434	7,609,122	6,388,180
Other Items ($)					
Capital expenditures	**5,563,667**	8,082,918	7,781,396	5,338,356	8,959,153
Total plant, before accumulated depreciation	**192,127,184**	187,148,032	182,155,110	174,711,253	170,337,427

(a) We recorded 58,000 Mcf of unbilled sales at June 30, 2005, resulting in non-recurring increases of $1,246,000 in operating revenues, $617,000 in operating income, $379,000 in net income and $.12 in basic and diluted earnings per common share for fiscal 2005.

(b) We implemented new regulated base rates as approved by the Kentucky Public Service Commission in October, 2007 and October, 2004, and the rates were designed to generate additional annual revenue of $3,920,000 and $2,756,000, respectively.

(c) During April, 2006, we issued $40,000,000 aggregate principal amount of 5.75% Insured Quarterly Notes due 2021. The net proceeds of the offering were $37,671,000. We used the net proceeds to redeem $23,700,000 and $10,200,000 aggregate principal amount of our 7.15% Debentures due 2018 and 6 5/8% Debentures due 2023, respectively. The remaining net proceeds of $3,830,000 were used to pay down our bank line of credit.

(d) Includes current portion of long-term debt.

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

Overview of 2008 and Future Outlook

Overview

The following is a discussion of the segments in which we compete, our corporate strategy for the conduct of our business within these segments and significant events that have occurred during 2008. Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment, and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production.

Earnings from the regulated segment are primarily influenced by sales and transportation volumes, the rates we charge our customers and the expenses we incur. In order for us to achieve our strategy of maintaining reasonable long-term earnings, cash flow and stock value, we must successfully manage each of these factors. Sales volumes are temperature-sensitive. Our regulated sales volumes in any period reflect the impact of weather, with colder temperatures generally resulting in increased sales volumes. The impact of unusual winter temperatures on our revenues is reduced given our ability to adjust our winter rates for residential and small non-residential customers in response to unusual winter temperatures. During 2008 we received an order from the Kentucky Public Service Commission, which granted us an increase in the base rates we charge our customers. The order was the result of a settlement agreement we reached with the Kentucky Attorney General in our rate case. The increased rates became effective in October, 2007 and are designed to annually generate an additional $3,920,000 in revenue.

Our non-regulated segment markets natural gas to large-use customers both on and off Delta's regulated system. We endeavor to enter sales agreements when we can match estimated demand with a supply that provides an acceptable margin.

Earnings per share increased between 2008 and 2007 ($.46 per share) due to the performance of both our regulated and non-regulated segments. The regulated segment experienced increased profitability due to the increased base rates implemented in October, 2007, as well as increased off-system volumes transported. Additionally, our non-regulated segment experienced increased profitability due to an increase in volumes sold.

Future Outlook

In 2009 and beyond, our success will depend, in part, on our ability to maintain a reasonable rate of return in our regulated segment in light of higher gas prices and the resultant conservation by our customers and additional loss of customers switching to alternate energy sources. In 2009, we will be implementing a conservation and efficiency program which is designed to encourage our residential customers to more efficiently use natural gas and to lessen the impact on us from such conservation. The Kentucky Public Service Commission sets the rates we are permitted to charge our customers in the regulated segment. We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our regulated services. Through these general rate cases, we seek approval from the Kentucky Public Service Commission to adjust the rates we charge our customers. The regulated segment's largest expense is gas supply, which we are permitted to pass through to our customers. We control remaining expenses through budgeting, approval and review.

We expect our non-regulated segment to continue to contribute to consolidated net income in 2009. Future profitability of the non-regulated segment, though, is dependent on the business plans of a few large customers and the market prices of natural gas, which are both out of our control. If natural gas prices continue to increase, we expect to experience a corresponding increase in our non-regulated margins related to our production activities. If natural gas prices decrease, we would expect a decrease in our non-regulated margins related to our natural gas production and marketing activities.

Liquidity and Capital Resources

Sources and Uses of Cash

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income adjusted for non-cash items, including depreciation, amortization, deferred income taxes and changes in working capital.

Our ability to maintain liquidity depends on our bank line of credit, shown as notes payable on the accompanying Consolidated Balance Sheets. Notes payable increased to $6,829,000 at June 30, 2008, compared with $4,190,000 at June 30, 2007. The $2,639,000 increase is attributable to decreased cash provided by operations. We made capital expenditures of $5,564,000, $8,083,000 and $7,781,000 during the fiscal years ended 2008, 2007 and 2006, respectively. We finance our seasonal cash needs through our bank line of credit. We periodically repay our short-term borrowings under our bank line of credit by using the net proceeds from the sale of long-term debt and equity securities, as was done in 2006 by a $3,830,000 repayment in connection with the issuance of the 5.75% Insured Quarterly Notes.

Long-term debt decreased to $58,318,000 at June 30, 2008, compared with $58,625,000 at June 30, 2007. This $307,000 decrease resulted from provisions in the Debentures and Insured Quarterly Notes allowing limited redemptions to be made to certain holders or their beneficiaries.

Cash and cash equivalents increased to $250,000 at June 30, 2008 compared with $188,000 at June 30, 2007. This $62,000 increase in cash and cash equivalents for the year ended June 30, 2008 is compared with the $38,000 and $23,000 increases in cash and cash equivalents for the years ended June 30, 2007 and June 30, 2006, respectively, as shown in the following table:

($000)	**2008**	2007	2006
Provided by operating activities	**6,592**	14,486	6,423
Used in investing activities	**(5,266)**	(7,936)	(7,577)
Provided by (used in) financing activities	**(1,264)**	(6,512)	1,177
Increase in cash and cash equivalents	**62**	38	23

In 2008, $7,894,000 less cash was provided by operating activities as compared to 2007. In 2008, we paid $15,288,000 more for gas due to increased commodity prices, increased volumes purchased and the timing of gas payables. This increase was partially offset due to $7,120,000 more cash received from customers due to increased prices and volumes sold (see related discussion in Results of Operations).

In 2007, cash provided by operating activities increased $8,063,000 as compared to 2006. In 2007, we paid $24,909,000 less for gas, partially offset by $16,052,000 less cash received from customers, both of which are a result of decreased sales volumes and cost of gas over the same time period (see related discussion in Results of Operations).

Changes in cash used in investing activities result primarily from changes in the level of capital expenditures between years.

In 2008, $5,248,000 less cash was used in financing activities due to increased net borrowings on our bank line of credit due to a corresponding decrease in cash provided by operating activities.

In 2007, $7,689,000 more cash was used in financing activities due to net repayments on our bank line of credit in the amount of $3,944,000. A further increase in cash used in 2007 in financing activities resulted from $3,480,000 being provided by financing activities in 2006 from the refinancing of the 7.15% and 6 5/8% Debentures. No such refinancing took place in 2007.

Cash Requirements

Our capital expenditures result in a continued need for capital. These capital expenditures are being made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities. We expect our capital expenditures for fiscal 2009 to be $7.9 million. The following is provided to summarize our contractual cash obligations for indicated periods after June 30, 2008:

	Payments Due by Period				
($000)	2009	2010-2011	2012-2013	After 2013	Total
Interest payments (a)	$ 4,406	$ 7,400	$ 7,400	$ 32,400	$ 51,606
Long-term debt (b)	1,200	2,400	2,400	53,518	59,518
Pension contributions (c)	677	1,000	1,000	8,054	10,731
Gas purchased (d)	898	—	—	—	898
Total contractual obligations	$ 7,181	$ 10,800	$ 10,800	$ 93,972	$ 122,753

(a) Our long-term debt, notes payable, customers' deposits and unrecognized tax positions all require interest payments. Interest payments are projected based on fiscal 2008 interest payments until the underlying obligation is satisifed. Interest on notes payable represents interest payments expected on the bank line of credit which extends through October 31, 2009. As of June 30, 2008, we have accrued $116,000 on interest related to uncertain tax positions. This amount has been excluded from the above table of contractual obligations as the timing of such payments is uncertain.

(b) See Note 9 of the Notes to Consolidated Financial Statements for a description of this debt. The cash obligations represent the maximum annual amount of redemptions to be made to certain holders or their beneficiaries through the debt maturity date. Our long-term debt does not have any sinking fund requirements.

(c) Represents currently projected contributions to the defined benefit plan through 2018, as recommended by our actuary.

(d) As of June 30, 2008, we had three contracts which have minimum purchase obligations whose terms extend through December, 2008. The remainder of our gas purchase contracts are requirement-based contracts or if a minimum purchase obligation exists thee contract does not extend for a time period greater than one month.

All of our operating leases are year-to-year and cancelable at our option.

See Note 12 of the Notes to Consolidated Financial Statements for other commitments and contingencies.

Sufficiency of Future Cash Flows

We expect that cash provided by operations, coupled with short-term and long-term borrowings, will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

To the extent that cash provided by operations is not sufficient to satisfy seasonal operating and capital expenditure requirements and to pay dividends, we will rely on our bank line of credit. Our current available bank line of credit is $40,000,000, of which $6,829,000 was borrowed at June 30, 2008 and classified as notes payable on the accompanying Consolidated Balance Sheet. The current bank line of credit is with Branch Banking and Trust Company and extends through October 31, 2009.

Our ability to sustain acceptable earnings levels, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated sales and transportation prices we charge our customers. The Kentucky Public Service Commission sets these prices, and we monitor our need to file rate requests with the Kentucky Public Service Commission for a general rate increase for our regulated services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. During October 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

Critical Accounting Policies and Estimates

Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles requires the use of assumptions and estimates regarding future events, including the likelihood of success of particular investments or initiatives, estimates of future prices or rates, legal and regulatory challenges, and anticipated recovery of costs. Therefore, the possibility exists for materially different reported amounts under different conditions or assumptions. We consider an accounting estimate to be critical if (i) the accounting estimate requires us to make assumptions about matters that were reasonably uncertain at the time the accounting estimate was made, and (ii) changes in the estimate are reasonably likely to occur from period to period.

These critical accounting estimates should be read in conjunction with the "Notes to Consolidated Financial Statements" in "Item 8. Financial Statements and Supplementary Data". We have other accounting policies that we consider to be significant; however, these policies do not meet the definition of critical accounting estimates, because they generally do not require us to make estimates or judgments that are particularly difficult or subjective.

Regulatory Accounting

Our accounting policies historically reflect the effects of the rate-making process in accordance with Financial Accounting Standards Board Statement No. 71, entitled Accounting for the Effects of Certain Types of Regulation. Our regulated segment continues to be cost-of-service rate regulated, and we believe the application of Statement No. 71 to that segment continues to be appropriate. We must reaffirm this conclusion at each balance sheet date. If, as a result of a change in circumstances, it is determined that the regulated segment no longer meets the criteria of regulatory accounting under Statement No. 71, that segment will have to discontinue regulatory accounting and write-off the respective regulatory assets and liabilities. Such a write-off could have a material impact on our consolidated financial statements.

The application of Statement No. 71 results in recording regulatory assets and liabilities. Regulatory assets represent the deferral of incurred costs that are probable of future recovery in customer rates. In some cases, we record regulatory assets before approval for recovery has been received from the Kentucky Public Service Commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base this conclusion on certain factors, including changes in the regulatory environment, recent rate orders issued by regulatory agencies and the status of any potential new legislation. Regulatory liabilities represent revenues received from customers to fund expected costs that have not yet been incurred or for probable future refunds to customers.

We use our best judgment when recording regulatory assets and liabilities; however, regulatory commissions can reach different conclusions about the recovery of costs, and those conclusions could have a material impact on our consolidated financial statements. We believe it is probable that we will recover the regulatory assets that have been recorded.

Pension

Our reported costs of providing pension benefits (as described in Note 5(a) of the Notes to Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs associated with our defined benefit pension plan, for example, are impacted by employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the

plan and earnings on plan assets. Changes made to the provisions of the plan may impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

Changes in pension obligations associated with the above factors may not be immediately recognized as pension costs on the Consolidated Statements of Income, but may be deferred and amortized in the future over the average remaining service period of active plan participants. For the years ended June 30, 2008, 2007 and 2006, we recorded pension costs for our defined benefit pension plan of $670,000, $567,000 and $717,000, respectively.

Our pension plan assets are principally comprised of equity and fixed income investments. Differences between actual portfolio returns and expected returns may result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

In selecting our discount rate assumption we considered rates of return on high-quality fixed-income investments that are expected to be available through the maturity dates of the pension benefits. Our expected long-term rate of return on pension plan assets was 7% for 2008 and was based on our targeted asset allocation assumption of approximately 65% equity investments and approximately 35% fixed income investments. Our target investment allocation for equity investments includes allocations to domestic, international, and emerging markets. Our asset allocation is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

We calculate the expected return on assets in our determination of pension costs based on the market value of assets at the measurement date. Using the market value recognizes investment gains or losses in the year in which they occur.

Based on an assumed long-term rate of return of 7%, discount rate of 6.5%, and various other assumptions, we estimate that our pension costs associated with our defined benefit pension plan will decrease from $670,000 in 2008 to $608,000 in 2009. Modifying the expected long-term rate of return on our pension plan assets by .25% would change pension costs for 2009 by approximately $36,000. Increasing the discount rate assumption by .25% would decrease pension costs by approximately $41,000. Decreasing the discount rate assumption by .25% would increase pension costs by approximately $43,000.

Effective May 9, 2008, any employees hired on and after that date are not eligible to participate in our defined benefit pension plan. Employees hired after May 9, 2008 will receive a 4% employer contribution into their Employee Savings Plan account. This contribution is discretionary and subject to change with approval from our Board of Directors. Freezing the plan to new entrants did not impact the level of benefits for existing participants.

Effective July 1, 2008, we adopted the measurement date provision of Financial Accounting Standards Board Statement No. 158 entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, which will require us to change the measurement date of our defined benefit plan from March 31 to June 30. Pension costs from April 1, 2008 to June 30, 2009 are expected to be $760,000. Of this amount, $152,000 is attributable to the change in measurement dates and will be charged directly to retained earnings on July 1, 2008. Thus, in fiscal 2009, pension costs in the amount of $608,000 are expected to be recognized in the Consolidated Statement of Income.

Provisions for Doubtful Accounts

We encounter risks associated with the collection of our accounts receivable. As such, we record a monthly provision for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, we primarily utilize our historical experience related to accounts written-off. Quarterly, at a minimum, we review the reserve for reasonableness based on the level of revenue and the aging of the receivable balance. The underlying assumptions used for the allowance can change from period to period and the allowance could potentially cause a material impact to the Consolidated Statements of Income and working capital. The actual weather, commodity prices and other internal and external economic conditions, such as the mix of the customer base between residential, commercial and industrial, may vary significantly from our assumptions and may impact operating income.

Unbilled Revenues and Gas Costs

At each month-end, we estimate the gas service that has been rendered from the date the customer's meter was last read to month-end. This estimate of unbilled usage is based on projected base load usage for each day unbilled plus projected weather-sensitive usage for each degree day during the unbilled period. Unbilled revenues and gas costs are calculated from the estimate of unbilled usage multiplied by the rates in effect at month-end. Actual usage patterns may vary from these assumptions and may impact operating income.

Asset Retirement Obligations

We have accrued asset retirement obligations for gas well plugging and abandonment costs. Additionally, we have recorded asset retirement obligations required pursuant to Federal regulations related to the retirement of our service lines and mains, although the timing of such retirements is uncertain. The fair value of our retirement obligations are recorded at the time the obligations are incurred. We do not recognize asset retirement obligations with indeterminate useful lives. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time the liabilities are accreted for the change in their present value, through charges to depreciation, and the initial capitalized costs are depreciated over the useful lives of the related assets. For asset retirement obligations attributable to assets of our regulated operations, the depreciation and accretion are deferred as a regulatory asset. We must use judgment to identify all appropriate asset retirement obligations. The underlying assumptions used for the value of the retirement obligations and related capitalized costs can change from period to period. These assumptions include the estimated future retirement costs, the estimated retirement date and the assumed credit-adjusted risk-free interest rate. Our asset retirement obligations are discussed in Note 3 of the Notes to Consolidated Financial Statements.

New Accounting Pronouncements

Significant management judgment is generally required during the process of adopting new accounting pronouncements. See Note 2 of the Notes to Consolidated Financial Statements for a discussion of these pronouncements.

Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations and the other sections of this report contain forward-looking statements that relate to future events or our future performance. We have attempted to identify these statements by using words such as "estimates", "attempts", "expects", "monitors", "plans", "anticipates", "intends", "continues", "strives" ,"seeks", "will rely", "believes" and similar expressions.

These forward-looking statements include, but are not limited to, statements about:

- our operational plans,
- the cost and availability of our natural gas supplies,
- our capital expenditures,
- sources and availability of funding for our operations and expansion,
- our anticipated growth and growth opportunities through system expansion and acquisition,
- competitive conditions that we face,
- our production, storage, gathering and transportation activities,
- acquisition of service franchises from local governments,
- pension fund costs and management,
- our contractual obligations and cash requirements,
- management of our gas supply and risks due to potential fluctuation in the price of natural gas,
- our revenues, income, margins and profitability,
- our efforts to purchase and transport locally produced natural gas,
- recovery of regulatory assets,
- regulatory and legislative matters, and
- dividends.

Our forward-looking statements are not guarantees of future performance and are based upon currently available competitive, financial and economic data along with our operating plans.

Factors that could cause future results to differ materially from those expressed in or implied by the forward-looking statements or historical results include the impact or outcome of:

- the ongoing restructuring of the natural gas industry and the outcome of the regulatory proceedings related to that restructuring,
- general changes in the regulatory environment,
- a change in the rights under present regulatory rules to recover for costs of gas supply, other expenses and investments in capital assets,
- uncertainty of our capital expenditure requirements,
- changes in economic conditions, demographic patterns and weather conditions in our retail service areas,
- changes affecting our costs of providing gas service, including changes in gas supply costs, interest rates, the availability of external sources of financing for our operations, tax laws, environmental laws and the general rate of inflation,
- conservation by customers and loss of customers due to higher gas prices,
- changes affecting the costs of competing energy alternatives and competing gas distributors,
- changes in accounting principles and tax laws or the application of such principles and laws to us, and
- other matters described in Item 1A. Risk Factors.

Results of Operations

Gross Margins

Our regulated and non-regulated revenues, other than transportation, have offsetting gas expenses. Therefore, throughout the following Results of Operations, we refer to "gross margin". With respect to our regulated and non-regulated segments, gross margin refers to operating revenues less purchased gas expense, which can be derived directly from our Consolidated Statements of Income. Operating Income as presented in the Consolidated Statements of Income is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). "Gross margin" is a "non-GAAP financial measure", as defined in accordance with SEC rules. We view gross margin as an important performance measure of the core profitability of our operations. This measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Natural gas prices are determined by an unregulated national market. Therefore, the price that we pay for natural gas fluctuates with national supply and demand. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for the impact of forward contracts.

In the following table we set forth variations in our gross margins for the last two fiscal years compared with the same periods in the preceding year. The variation amounts and percentages presented in the following tables for regulated and non-regulated gross margins include intersegment transactions. These intersegment revenues and expenses are eliminated in the Consolidated Statements of Income.

($000)	**2008 compared to 2007**	2007 compared to 2006
Increase (decrease) in regulated gross margins		
Gas sales	**1,349**	333
On-system transportation	**203**	(112)
Off-system transportation	**884**	436
Other	**(324)**	(155)
Total	**2,112**	502
Increase in non-regulated gross margins		
Gas sales	**1,441**	615
Other	**114**	16
Total	**1,555**	631
Increase in consolidated gross margins	**3,667**	1,133
Percentage increase (decrease) in regulated volumes		
Gas sales	**(5.4)**	1.8
On-system transportation	**(3.6)**	(3.0)
Off-system transportation	**29.1**	11.2
Percentage increase in non-regulated gas sales volumes	**9.6**	11.9

Heating degree days were 96% of normal thirty year average temperatures for fiscal 2008, as compared with 95% and 92% of normal temperatures for 2007 and 2006, respectively. A "heating degree day" results from a day during which the average of the high and low temperature is at least one degree less than 65 degrees Fahrenheit.

Gross margins increased $3,667,000 in 2008 due to an increase in regulated gross margins of $2,112,000 and an increase in non-regulated gross margins of $1,555,000.

The $2,112,000 (9%) increase in regulated gross margins is attributable to increased base rates which became effective October 20, 2007 and a 2,849,000 Mcf (29%) increase in regulated off-system volumes transported. The impact of the increased rates was partially offset by a 178,000 Mcf (5%) decrease in volumes sold attributable to customer conservation.

The $1,555,000 (16%) increase in non-regulated gross margins is primarily attributable to a 569,000 Mcf (19%) increase in off-system volumes sold.

Gross margins increased $1,133,000 (4%) in 2007 due to an increase in non-regulated gross margins of $631,000 and a $502,000 increase in regulated gross margins.

The $631,000 (7%) increase in non-regulated gross margins in 2007 is primarily attributable to a 523,000 Mcf (12%) increase in volumes sold.

The $502,000 (2%) increase in regulated gross margins in 2007, is primarily attributable to a 985,000 Mcf increase in off-system transportation volumes (11%) and the 3% colder weather in 2007. These increases were offset by a 2% decrease in the number of regulated customers.

Operations and Maintenance

The $1,544,000 (12%) increase in operations and maintenance expense is primarily attributable to increased uncollectible expense ($326,000), increased storage maintenance expense ($307,000), increased labor expense ($274,000), increased transportation expenses ($165,000) and increased maintenance of transmission and distribution mains ($133,000).

Depreciation and Amortization

The $527,000 (11%) decrease in depreciation and amortization is primarily due to lower depreciation rates approved by the Kentucky Public Service Commission that became effective October 20, 2007. The decrease was partially offset by increases in depreciable plant resulting from capital expenditures which relate to the replacement and improvement of our transmission, distribution, gathering, storage and general facilities.

The $494,000 (12%) increase in depreciation and amortization for 2007 is primarily due to an increase in depreciable plant resulting from capital expenditures of $8,083,000 for the replacement and improvement of our transmission, distribution, gathering, storage and general facilities.

Other Interest

The increase in other interest for 2008 of $139,000 (25%) was a result of increased borrowings on our bank line of credit.

The decrease in other interest for 2007 of $169,000 (23%) was a result of decreased borrowings on our bank line of credit.

Income Tax Expense

The $990,000 (31%) increase in income tax expense for 2008 was attributable to the increase in net income before income taxes in 2008. Net income before income taxes increased due to the factors discussed throughout the "Results of Operations".

Basic and Diluted Earnings Per Common Share

For the fiscal years ended June 30, 2008, 2007 and 2006, our basic earnings per common share changed as a result of changes in net income and an increase in the number of our common shares outstanding.

We have no potentially dilutive securities. As a result, our basic earnings per common share and our diluted earnings per common share are the same.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. The price of spot market gas is based on the market price at the time of delivery. The price we pay for our natural gas supply acquired under our forward gas purchase contracts, however, is fixed prior to the delivery of the gas. Additionally, we inject some of our gas purchases into gas storage facilities in the non-heating months and withdraw this gas from storage for delivery to customers during the heating season. For our regulated business, we have minimal price risk resulting from these forward gas purchase and storage arrangements because we are permitted to pass these gas costs on to our regulated customers through the gas cost recovery rate mechanism, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to price risk resulting from changes in the market price of gas on uncommitted gas volumes of our non-regulated companies.

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts and gas sales contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Financial Accounting Standards Board Statement No. 133, entitled Accounting for Derivative Instruments and Hedging Activities.

We are exposed to risk resulting from changes in interest rates on our variable rate bank line of credit. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly London Interbank Offered Rate. The balance on our bank line of credit was $6,829,000 and $4,190,000 on June 30, 2008 and 2007, respectively. The weighted average interest rate on our bank line of credit was 3.2% and 6.3% as of June 30, 2008 and 2007, respectively. Based on the amount of our outstanding bank line of credit on June 30, 2008 and 2007, a 1% (one hundred basis points) increase in our average interest rate would result in a decrease in our annual pre-tax net income of $68,000 and $42,000, respectively.

Item 8. Financial Statements and Supplementary Data

Schedules other than those listed above are omitted because they are not required, are not applicable or the required information is shown in the financial statements or notes thereto.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure controls and procedures are our controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's ("SEC") rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a – 15(e) and 15d – 15(e) under the Exchange Act) as of June 30, 2008 and based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in

providing reasonable assurance that information requiring disclosure is recorded, processed, summarized, and reported within the time frame specified by the SEC's rules and forms.

Our management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principles.

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

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of June 30, 2008 based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on that evaluation, management concluded that our internal control over financial reporting was effective as of June 30, 2008.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter ended June 30, 2008 and found no change that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on our internal control over financial reporting. That report immediately follows:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Delta Natural Gas Company, Inc.:

We have audited the internal control over financial reporting of Delta Natural Gas Company, Inc. and subsidiaries (the "Company") as of June 30, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Certification of the Chief Executive Officer and Certification of the Chief Financial Officer. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of June 30, 2008, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended June 30, 2008 of the Company and our report dated August 28, 2008 expressed an unqualified opinion on those financial statements and financial statement schedule, and included explanatory paragraphs regarding the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement 109* and Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

/S/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 28, 2008

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance of the Registrant

We have a Business Code of Conduct and Ethics that applies to all directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. You can find our Business Code of Conduct and Ethics on our website by going to the following address: http://www.deltagas.com. We will post any amendments to the Business Code of Conduct and Ethics, as well as any waivers that are required to be disclosed by the rules of either the Securities and Exchange Commission or the NASDAQ OMX Group, on our website.

Our Board of Directors has adopted charters for the Audit, Corporate Governance and Compensation and Executive Committees of the Board of Directors. You can find these documents on our website by going to the following address: http://www.deltagas.com and clicking on the appropriate link.

You can also obtain a printed copy of any of the materials referred to above by contacting us at the following address:

Delta Natural Gas Company, Inc.
Attn: John B. Brown
3617 Lexington Road
Winchester, KY 40391
(859) 744-6171

The Audit Committee of our Board of Directors is an "audit committee" for purposes of Section 3(a)(58) of the Securities Exchange Act of 1934.

The other information required by this Item is incorporated herein by reference to the applicable information in the proxy statement for our 2008 annual meeting.

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Item 13. Certain Relationships and Related Transactions, and Director Independence

Item 14. Principal Accountant Fees and Services

Registrant intends to file a definitive proxy statement with the Commission pursuant to Regulation 14A (17 CFR 240.14a) no later than 120 days after the close of the fiscal year. In accordance with General Instruction G(3) to Form 10-K, the information called for by Items 10 (except for the language above in Item 10 in this report), 11, 12, 13 and 14 is incorporated herein by reference to the definitive proxy statement. The Report on Executive Compensation included in the Company's definitive proxy statement shall not be deemed incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Schedules and Exhibits

(1) Financial Statements
See Index at Item 8

(2) Financial Statement Schedules
See Index at Item 8

(3) Exhibits

<u>Exhibit No.</u>

3(i) Registrant's Amended and Restated Articles of Incorporation (dated November 16, 2006) are incorporated herein by reference to Exhibit 3(i) to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2007.

3(ii) Registrant's Amended and Restated By-Laws (dated November 16, 2006) are incorporated herein by reference to Exhibit 3(ii) to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2007.

4(a) The Indenture dated March 1, 2006 in respect of 5.75% Insured Quarterly Notes due April 1, 2021, is incorporated herein by reference to Exhibit 4(d) to Delta's Form S-3 (Reg. No. 333-132322) dated March 31, 2006.

4(b) The Indenture dated January 1, 2003 in respect of 7% Debentures due February 1, 2023, is incorporated herein by reference to Exhibit 4(d) to Delta's Form S-2 (Reg. 333-100852) dated October 30, 2002.

10(a) Employment agreements between Registrant and four officers, those being John B. Brown, Johnny L. Caudill, Alan L. Heath and Glenn R. Jennings, are incorporated herein by reference to Exhibit 10(k) to Registrant's Form 10-Q (File No. 000-08788) for the period ended March 31, 2000.

10(b) Supplemental retirement benefit agreement and trust agreement between Registrant and Glenn R. Jennings is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated February 25, 2005.

10(c) Gas Sales Agreement, dated May 1, 2005, by and between the Registrant and Atmos Energy Marketing, L.L.C is filed herewith.

10(d) Gas Sales Agreement, dated May 1, 2003, by and between the Registrant and Atmos Energy Marketing, LLC is filed herewith.

10(e) Gas Transportation Agreement (Service Package 9069), dated December 19, 1994, by and between Tennessee Gas Pipeline Company and Registrant is incorporated herein by reference to Exhibit 10(e) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.

10(f) GTS Service Agreement (Service Agreement No. 37815), dated November 1, 1993, by and between Columbia Gas Transmission Corporation and Registrant is incorporated herein by reference to Exhibit 10(f) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.

10(g) FTS1 Service Agreement (Service Agreement No. 4328), dated October 4, 1994, by and between Columbia Gulf Transmission Company and Registrant is incorporated herein by reference to Exhibit 10(g) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003

10(h) Loan Agreement, dated October 31, 2002, by and between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(i) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.

10(i) Promissory Note, in the original principal amount of $40,000,000, made by Registrant to the order of Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2002.

10(j) Gas Storage Lease, dated October 4, 1995, by and between Judy L. Fuson, Guardian of Jamie Nicole Fuson, a minor, and Lonnie D. Ferrin and Assignment and Assumption Agreement, dated November 10, 1995, by and between Lonnie D. Ferrin and Registrant is incorporated herein by reference to Exhibit 10(j) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(k) Gas Storage Lease, dated November 6, 1995, by and between Thomas J. Carnes, individually and as Attorney-in-fact and Trustee for the individuals named therein, and Registrant, is incorporated herein by reference to Exhibit 10(k) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003

10(l) Deed and Perpetual Gas Storage Easement, dated December 21, 1995, by and between Katherine M. Cornelius, William Cornelius, Frances Carolyn Fitzpatrick, Isabelle Fitzpatrick Smith and Kenneth W. Smith and Registrant is incorporated herein by reference to Exhibit 10(l) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(m) Underground Gas Storage Lease and Agreement, dated March 9, 1994, by and between Equitable Resources Exploration, a division of Equitable Resources Energy Company, and Lonnie D. Ferrin and Amendment No. 1 and Novation to Underground Gas Storage Lease and Agreement, dated March 22, 1995, by and between Equitable Resources Exploration, Lonnie D. Ferrin and Registrant, is incorporated herein by reference to Exhibit 10(m) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(n) Base Contract for Short-Term Sale and Purchase of Natural Gas, dated January 1, 2002, by and between M & B Gas Services, Inc. and Registrant, is incorporated herein by reference to Exhibit 10(n) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(o) Oil and Gas Lease, dated July 19, 1995, by and between Meredith J. Evans and Helen Evans and Paddock Oil and Gas, Inc.; Assignment, dated June 15, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; Assignment, dated August 31, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; and Assignment and Assumption Agreement, dated November 10, 1995, by and between Lonnie D. Ferrin and Registrant, is incorporated herein by reference to Exhibit 10(o) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(p) Agreement to transport natural gas between Registrant and Nami Resources Company L.L.C. is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated March 23, 2005.

10(q) Modification Agreement extending to October 31, 2009 the Promissory Note and Loan Agreement dated October 31, 2002 between the Registrant and Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2007.

12 Computation of the Consolidated Ratio of Earnings to Fixed Charges.

21 Subsidiaries of the Registrant.

23 Consent of Independent Registered Public Accounting Firm.

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 29th day of August, 2008.

DELTA NATURAL GAS COMPANY, INC.

By: /s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

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

(i) Principal Executive Officer:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 29, 2008

(ii) Principal Financial Officer and Principal Accounting Officer

/s/John B. Brown (John B. Brown)	Chief Financial Officer, Treasurer and Secretary	August 29, 2008

(iii) A Majority of the Board of Directors:

/s/Linda K. Breathitt (Linda K. Breathitt)	Director	August 29, 2008
/s/Lanny D. Greer (Lanny D. Greer)	Director	August 29, 2008
/s/Billy Joe Hall (Billy Joe Hall)	Director	August 29, 2008
/s/Michael J. Kistner (Michael J. Kistner)	Director	August 29, 2008
/s/Lewis N. Melton (Lewis N. Melton)	Director	August 29, 2008
/s/Arthur E. Walker, Jr. (Arthur E. Walker, Jr.)	Director	August 29, 2008
/s/Michael R. Whitley (Michael R. Whitley)	Director	August 29, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Delta Natural Gas Company, Inc.:

We have audited the accompanying consolidated balance sheets of Delta Natural Gas Company, Inc. and subsidiaries (the "Company") as of June 30, 2008 and 2007, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended June 30, 2008. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at June 30, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, on July 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement 109*.

As discussed in Note 2 to the consolidated financial statements, on June 30, 2007, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of June 30, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated August 28, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/S/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 28, 2008

Delta Natural Gas Company, Inc.

Consolidated Statements of Income

For the Years Ended June 30,	**2008**	2007	2006
Operating Revenues	**$ 112,657,117**	$ 98,168,391	$ 117,247,144
Operating Expenses			
Purchased gas	**$ 76,882,387**	$ 66,060,368	$ 86,271,854
Operation and maintenance	**14,128,620**	12,584,607	12,293,652
Depreciation and amortization	**4,171,145**	4,697,639	4,203,711
Taxes other than income taxes	**1,811,229**	1,857,734	1,720,420
Total operating expenses	**$ 96,993,381**	$ 85,200,348	$ 104,489,637
Operating Income	**$ 15,663,736**	$ 12,968,043	$ 12,757,507
Other Income and Deductions, Net	**$ 83,521**	$ 134,265	$ 227,636
Interest Charges			
Interest on long-term debt	**$ 3,677,983**	$ 3,694,389	$ 3,968,993
Other interest	**705,240**	565,790	735,082
Amortization of debt expense	**387,266**	387,082	273,533
Total interest charges	**$ 4,770,489**	$ 4,647,261	$ 4,977,608
Income Before Income Taxes	**$ 10,976,768**	$ 8,455,047	$ 8,007,535
Income Tax Expense	**$ 4,146,900**	$ 3,156,700	$ 2,982,900
Net Income	**$ 6,829,868**	$ 5,298,347	$ 5,024,635
Basic and Diluted Earnings Per Common Share	**$ 2.08**	$ 1.62	$ 1.55
Weighted Average Number of Common Shares Outstanding (Basic and Diluted)	**3,285,464**	3,265,800	3,242,223
Dividends Declared Per Common Share	**$ 1.24**	$ 1.22	$ 1.20

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Statements of Cash Flows

For the Years Ended June 30,	**2008**	2007	2006
Cash Flows From Operating Activities			
Net income	**$ 6,829,868**	$ 5,298,347	$ 5,024,635
Adjustments to reconcile net income to net cash from operating activities			
Depreciation and amortization	**4,660,410**	5,157,922	4,550,444
Deferred income taxes and investment tax credits	**2,095,000**	2,345,300	1,814,475
Gain on sale of asset	**(16,955)**	—	—
Other - net	**(219,041)**	(205,827)	(73,869)
(Increase) decrease in assets			
Accounts receivable	**(5,016,055)**	1,746,732	(1,374,334)
Gas in storage	**(2,634,602)**	(475,801)	(2,172,326)
Deferred gas cost	**(1,670,877)**	(1,116,773)	819,453
Materials and supplies	**(38,568)**	(87,859)	103,365
Prepayments	**(129,153)**	(897,682)	(525,634)
Other assets	**(75,390)**	(197,887)	(772,733)
Increase (decrease) in liabilities			
Accounts payable	**1,920,832**	3,835,813	(668,039)
Accrued taxes	**890,309**	(1,061,563)	(226,523)
Other current liabilities	**(889)**	148,901	(66,759)
Other liabilities	**(2,358)**	(3,717)	(9,107)
Net cash provided by operating activities	**$ 6,592,531**	$ 14,485,906	$ 6,423,048
Cash Flows From Investing Activities			
Capital expenditures	**$ (5,563,667)**	$ (8,082,918)	$ (7,781,396)
Proceeds from sale of property, plant and equipment	**297,425**	146,810	204,372
Net cash used in investing activities	**$ (5,266,242)**	$ (7,936,108)	$ (7,577,024)

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Statements of Cash Flows (continued)

For the Years Ended June 30,	**2008**	2007	2006
Cash Flows From Financing Activities			
Dividends on common stock	**$ (4,073,278)**	$ (3,983,909)	$ (3,890,800)
Issuance of common stock, net	**477,155**	504,309	676,435
Long-term debt issuance expense	—	(10,970)	(2,329,393)
Issuance of long-term debt	—	—	40,000,000
Repayment of long-term debt	**(307,000)**	(165,000)	(34,367,000)
Issuance of notes payable	**64,602,956**	51,518,605	92,710,796
Repayment of notes payable	**(61,964,083)**	(54,375,121)	(91,623,484)
Net cash (used in) provided by financing activities	**$ (1,264,250)**	$ (6,512,086)	$ 1,176,554
Net Increase in Cash and Cash Equivalents	**$ 62,039**	$ 37,712	$ 22,578
Cash and Cash Equivalents, Beginning of Year	**187,820**	150,108	127,530
Cash and Cash Equivalents, End of Year	**$ 249,859**	$ 187,820	$ 150,108
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year for			
Interest	**$ 4,383,367**	$ 4,232,155	$ 4,766,191
Income taxes (net of refunds)	**1,376,093**	1,763,518	1,922,348

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Balance Sheets

As of June 30,		**2008**		2007
Assets				
Current Assets				
Cash and cash equivalents	**$**	**249,859**	$	187,820
Accounts receivable, less provisions for doubtful accounts of $465,000 and $300,000 in 2008 and 2007, respectively		**11,437,219**		7,389,993
Gas in storage, at average cost		**14,476,393**		11,841,791
Deferred gas costs (Note 1 and 13)		**4,612,752**		2,941,826
Materials and supplies, at average cost		**565,333**		559,087
Prepayments		**2,683,854**		2,629,682
Total current assets	**$**	**34,025,410**	$	25,550,199
Property, Plant and Equipment	**$**	**192,127,184**	$	187,148,032
Less – Accumulated provision for depreciation		**(67,754,068)**		(64,879,205)
Net property, plant and equipment	**$**	**124,373,116**	$	122,268,827
Other Assets				
Cash surrender value of officers' life insurance (face amount of $1,146,786)	**$**	**444,312**	$	425,609
Prepaid pension cost (Note 5)		**1,423,932**		951,571
Regulatory assets (Note 1)		**7,713,358**		8,220,590
Unamortized debt expense and other (Notes 1 and 9)		**2,834,728**		2,984,154
Total other assets	**$**	**12,416,330**	$	12,581,924
Total assets	**$**	**170,814,856**	$	160,400,950

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc. and Subsidiary Companies

Consolidated Balance Sheets (continued)

As of June 30,		2008		2007
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable	**$**	**12,154,432**	$	10,299,066
Notes payable (Note 8)		**6,828,791**		4,189,918
Current portion of long-term debt (Notes 9 and 10)		**1,200,000**		1,200,000
Accrued taxes		**1,656,391**		973,651
Customers' deposits		**505,058**		482,446
Accrued interest on debt		**865,727**		865,871
Accrued vacation		**720,625**		702,521
Deferred income taxes		**1,483,700**		1,273,000
Other liabilities		**418,239**		459,651
Total current liabilities	**$**	**25,832,963**	$	20,446,124
Long-term debt (Notes 9 and 10)	**$**	**58,318,000**	$	58,625,000
Deferred Credits and Other				
Deferred income taxes	**$**	**24,576,000**	$	22,467,900
Investment tax credits		**177,800**		213,600
Regulatory liabilities (Note 1)		**2,144,951**		2,503,256
Asset retirement obligations and other (Note 3)		**2,171,557**		1,716,599
Total deferred credits and other	**$**	**29,070,308**	$	26,901,355
Commitments and Contingencies (Note 12)				
Total liabilities	**$**	**113,221,271**	$	105,972,479
Common Shareholders' Equity				
Common shares ($1.00 par value), 20,000,000 shares authorized; 3,295,759 and 3,277,106 shares outstanding at June 30, 2008 and June 30, 2007, respectively	**$**	**3,295,759**	$	3,277,106
Premium on common shares		**43,967,481**		43,508,979
Retained earnings		**10,330,345**		7,642,386
Total common shareholders' equity	**$**	**57,593,585**	$	54,428,471
Total liabilities and common shareholders' equity	**$**	**170,814,856**	$	160,400,950

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Statements of Changes in Shareholders' Equity

For the Years Ended June 30,	2008	2007	2006
Common Shares			
Balance, beginning of year	$ 3,277,106	$ 3,256,043	$ 3,229,988
Dividend reinvestment and stock purchase plan, $1.00 par value of 18,653, 21,063 and 26,055 shares issued in 2008, 2007 and 2006, respectively	18,653	21,063	26,055
Balance, end of year	$ 3,295,759	$ 3,277,106	$ 3,256,043
Premium on Common Shares			
Balance, beginning of year	$ 43,508,979	$ 43,025,733	$ 42,375,353
Dividend reinvestment and stock purchase plan	458,502	483,246	650,380
Balance, end of year	$ 43,967,481	$ 43,508,979	$ 43,025,733
Retained Earnings			
Balance, beginning of year	$ 7,642,386	$ 6,327,948	$ 5,194,113
Adoption of FASB Interpretation No. 48	(68,631)	—	—
Balance, beginning of year, as adjusted	$ 7,573,755	$ 6,327,948	$ 5,194,113
Net income	6,829,868	5,298,347	5,024,635
Cash dividends declared on common shares (See Consolidated Statements of Income for rates)	(4,073,278)	(3,983,909)	(3,890,800)
Balance, end of year	$ 10,330,345	$ 7,642,386	$ 6,327,948
Common Shareholders' Equity			
Balance, beginning of year	$ 54,428,471	$ 52,609,724	$ 50,799,454
Adoption of FASB Interpretation No. 48	(68,631)	—	—
Balance, beginning of year, as adjusted	$ 54,359,840	$ 52,609,724	$ 50,799,454
Net income	6,829,868	5,298,347	5,024,635
Issuance of common stock	477,155	504,309	676,435
Dividends on common stock	(4,073,278)	(3,983,909)	(3,890,800)
Balance, end of year	$ 57,593,585	$ 54,428,471	$ 52,609,724

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

(a) Principles of Consolidation Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 38,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties and undeveloped acreage. All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

(b) Cash Equivalents For the purposes of the Consolidated Statements of Cash Flows, all temporary cash investments with a maturity of three months or less at the date of purchase are considered cash equivalents.

(c) Property, Plant and Equipment Property, plant and equipment is stated at original cost, which includes materials, labor, labor related costs and an allocation of general and administrative costs. Construction work in progress has been included in the rate base for determining customer rates, and therefore an allowance for funds used during construction has not been recorded. The cost of regulated plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost, plus removal expense, less salvage value, is charged to the accumulated provision for depreciation.

(d) Depreciation We determine the provision for depreciation using the straight-line method and by the application of rates to various classes of utility plant. The rates are based upon the estimated service lives of the properties and were equivalent to composite rates of 2.3%, 2.7% and 2.5% of average depreciable plant for 2008, 2007 and 2006, respectively.

(e) Maintenance All expenditures for maintenance and repairs of units of property are charged to the appropriate maintenance expense accounts in the month incurred. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired.

(f) Gas Cost Recovery We have a Gas Cost Recovery ("GCR") clause which provides for a dollar-tracker that matches revenues and gas costs and provides eventual dollar-for-dollar recovery of all gas costs incurred by the regulated segment and approved by the Kentucky Public Service Commission. We expense gas costs based on the amount of gas costs recovered through revenue. Any differences between actual gas costs and those estimated costs billed are deferred and reflected in the computation of future billings to customers using the GCR mechanism.

(g) Revenue Recognition We bill our customers on a monthly meter reading cycle. At the end of each month, gas service which has been rendered from the date the customer's meter was last read to the month-end is unbilled.

Unbilled revenues and gas costs include the following:

(000)	**2008**	2007
Unbilled revenues ($)	**1,579**	1,058
Unbilled gas costs ($)	**736**	497
Unbilled volumes (Mcf)	**51**	48

Unbilled revenues are included in accounts receivable and unbilled gas costs are included in deferred gas costs on the accompanying Consolidated Balance Sheets.

(h) Excise Taxes Certain excise taxes levied by state or local governments are collected by Delta from our customers. These taxes are accounted for on a net basis and therefore are not included as revenues in the accompanying Consolidated Statements of Income.

(i) Revenues and Customer Receivables We serve 38,000 customers in central and southeastern Kentucky. Revenues and customer receivables arise primarily from sales of natural gas to customers and from transportation services for others. Provisions for doubtful accounts are recorded to reflect the expected net realizable value of accounts receivable. Customer accounts are charged off when deemed to be uncollectible or when turned over to a collection agency to pursue.

(j) Use of Estimates The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(k) Rate Regulated Basis of Accounting Our regulated operations follow the accounting and reporting requirements of Financial Accounting Standards Board Statement No. 71, entitled Accounting for the Effects of Certain Types of Regulation. The economic effects of regulation can result in a regulated company recovering costs 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 Sheets (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). The amounts recorded as regulatory assets and regulatory liabilities are as follows:

($000)

Regulatory assets	2008	2007
Current assets		
Deferred gas costs	**4,613**	2,942
Other assets		
Loss on extinguishment of debt	**2,539**	2,729
Asset retirement obligations	**1,352**	1,249
Accrued pension	**3,538**	3,935
Regulatory case expenses	**285**	307
Total other assets	**7,714**	8,220
Total regulatory assets	**12,327**	11,162
Regulatory liabilities		
Accrued cost of removal on long-lived assets	**615**	785
Regulatory liability for deferred income taxes	**1,530**	1,718
Total regulatory liabilities	**2,145**	2,503

Deferred gas costs are presented every three months to the Kentucky Public Service Commission for recovery in accordance with the gas cost recovery rate mechanism. We are currently earning a return on loss on extinguishment of debt. Asset retirement costs are recovered through customer rates as they are included in our depreciation rates. Pension expenses and rate case expenses are recovered through customer rates as allowed operating expenses.

(l) Impairment of Long-Lived Assets We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for an impairment loss if the carrying value is greater than the fair value. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. In the opinion of management, our long-lived assets are appropriately valued in the accompanying consolidated financial statements.

(m) Derivatives We purchase and sell natural gas. Certain of our gas purchase and sale contracts qualify as a derivative under Financial Accounting Standards Board Statement No. 133, entitled Accounting for Derivative Instruments and Hedging Activities. All such contracts have been designated as normal purchases and sales and as such are accounted for under the accrual basis and are not recorded at fair value in the accompanying consolidated financial statements.

(2) New Accounting Pronouncements

Recently Adopted Pronouncements

In July, 2006, the FASB issued Interpretation No. 48, entitled Accounting for Uncertainty in Income Taxes, to clarify the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with Financial Accounting Standards Board Statement No. 109, entitled Accounting for Income Taxes. Interpretation No. 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under Interpretation No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

We adopted the provisions of Interpretation No. 48 on July 1, 2007. The adoption of Interpretation No. 48 resulted in an adjustment to beginning retained earnings of $68,000. At adoption, the total amount of gross unrecognized tax benefits for uncertain tax positions, including positions impacting only the timing of tax benefits, was $668,000, of which $97,000 related to interest. Note 4 of the Notes to Consolidated Financial Statements further discusses our income taxes.

We have not entered into any share-based payment transactions, therefore, the adoption of Statement of Financial Accounting Standards No. 123(R), entitled Share-Based Payment, and Securities and Exchange Commission Staff Accounting Bulletin No. 107, entitled Share-Based Payment, had no impact on us.

In September, 2006, the Financial Accounting Standards Board issued Statement No. 158, entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans. Statement No. 158 requires employers who sponsor defined benefit plans to recognize the funded status of the plan and gains and losses not previously recognized in net periodic benefit cost in the sponsor's financial statements in fiscal years ending after December 15, 2006. Additionally, Statement No. 158 requires employers who sponsor defined benefit plans to measure assets and benefit obligations as of the end of the employer's fiscal year in fiscal years beginning after December 15, 2007. Statement No. 71 provides guidance to regulated utilities for deferring costs that would otherwise be charged to expense or equity by non-regulated enterprises. We adopted the disclosure and recognition provisions of Statement No. 158 effective June 30, 2007 and in applying the provisions of this statement, we recorded a regulatory asset representing the adjustment to the pension asset in recognizing the funded status of the plan. This adjustment would have been represented in Accumulated Other Comprehensive Income without the application of Statement No. 71. The adoption of Statement No. 158 recognition and disclosure provisions resulted in an increase in regulatory assets of $3,935,000 offset by a decrease in prepaid pension cost of $3,935,000. The adoption of Statement No. 158, as further discussed in Note 5 of the Notes to Consolidated Financial Statements, did not have any impact on our consolidated results of operations or cash flows.

Effective July 1, 2008, we will adopt the measurement date provision of Statement No. 158, which will require us to change the measurement date of our defined benefit plan from March 31 to June 30. Pension costs from April 1, 2008 to June 30, 2009 are expected to be $760,000. Of this amount, $152,000 is attributable to the change in measurement dates and will be charged directly to retained earnings on July 1, 2008. In fiscal 2009, pension costs in the amount of $608,000 are expected to be recognized in the Consolidated Statement of Income.

Recently Issued Pronouncements

In September, 2006, the Financial Accounting Standards Board issued Statement No. 157, entitled Fair Value Measures, and in February 2007 it issued Statement No. 159, entitled The Fair Value Option for Financial Assets and Financial Liabilities. Both statements are effective for fiscal years beginning after

November 15, 2007. The statements define fair value, establish a framework for measuring fair value in generally accepted accounting principles and expand disclosures about fair value measurements. We do not expect these statements, which shall be effective for our 2009 fiscal year, to have a material impact on our results of operations or financial position.

In February, 2008, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. 157-2, entitled Effective Date of FASB Statement No. 157, which delays the effective date of Statement No. 157 for one year for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis.

In March, 2008, the Financial Accounting Standards Board issued Statement No. 161, entitled Disclosures about Derivative Instruments and Hedging Activities. Statement No. 161 enhances the disclosures as required by Statement No. 133. Entities are required to provide enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. We do not expect this statement, which shall be effective for our 2010 fiscal year, to have an impact on our results of operations or financial position.

(3) Asset Retirement Obligations Legal obligations

As required by Financial Accounting Standards Board Statement No. 143, entitled Accounting for Asset Retirement Obligations, and Financial Accounting Standards Interpretation No. 47, entitled Accounting for Conditional Asset Retirement Obligations, as of June 30, 2008 and 2007 we have accrued liabilities and related assets, net of accumulated depreciation, relative to the legal obligation to retire certain gas wells, storage tanks, mains and services. For asset retirement obligations related to regulated assets, accretion of the liability and depreciation of the asset retirement costs are recorded as regulatory assets, pursuant to Statement No. 71, as we recover the cost of removing our regulated assets through our depreciation rates.

The following is a summary of our asset retirement obligations and related assets (net of accumulated depreciation), reflected in the accompanying Consolidated Balance Sheets under the captions asset retirement obligations and other, and property, plant and equipment, respectively:

($000)	Asset Retirement Obligations	Net Assets
As of June 30, 2006	1,578	274
Accretion	120	—
Depreciation	—	(10)
Change in obligations	(232)	(232)
As of June 30, 2007	1,466	32
Accretion	111	—
Depreciation	—	(2)
Change in obligations	23	23
As of June 30, 2008	1,600	53

We have an additional asset retirement obligation relative to the retirement of wells located at our underground natural gas storage facility. Since we expect to utilize the storage facility as long as we provide natural gas to our customers, we have determined the underlying asset has an indeterminate life. Therefore, we have not recorded a liability associated with the cost to retire the asset, pursuant to Interpretation No. 47.

Non-legal obligations

In accordance with established regulatory practices, we accrue costs of removal on long-lived assets through depreciation expense if we believe removal of the assets at the end of their useful life is likely even though such costs do not represent legal obligations under Statement No. 143. In accordance with the provisions of Statement No. 71, we have recorded approximately $615,000 and $785,000 of such accrued cost of removal as regulatory liabilities on the accompanying Consolidated Balance Sheets as of June 30, 2008 and 2007, respectively.

(4) Income Taxes

We provide for income taxes on temporary differences resulting from the use of alternative methods of income and expense recognition for financial and tax reporting purposes. The differences result primarily from the use of accelerated tax depreciation methods for certain properties versus the straight-line depreciation method for financial reporting purposes, differences in recognition of purchased gas costs and certain accruals which are not currently deductible for income tax purposes. Investment tax credits were deferred for certain periods prior to fiscal 1987 and are being amortized to income over the estimated useful lives of the applicable properties. We utilize the asset and liability method for accounting for income taxes, which requires that deferred income tax assets and liabilities be computed using tax rates that will be in effect when the book and tax temporary differences reverse. Changes in tax rates applied to accumulated deferred income taxes are not immediately recognized in operating results because of ratemaking treatment. A regulatory liability has been established to recognize the regulatory obligation to refund these excess deferred taxes through customer rates. The current portion of net accumulated deferred income tax liability is shown as current liabilities and the long-term portion is included in deferred credits and other on the accompanying Consolidated Balance Sheets. The temporary differences which gave rise to the net accumulated deferred income tax liability for the periods are as follows:

($000)	**2008**	2007
Deferred Tax Liabilities		
Accelerated depreciation	**23,251**	21,036
Deferred gas costs	**1,751**	1,116
Pension	**515**	921
Regulatory assets – loss on extinguishment of debt	**964**	1,036
Regulatory assets – asset retirement obligations	**513**	474
Regulatory assets – unrecognized accrued pension	**1,343**	1,494
Other	**445**	448
Total	**28,782**	26,525
Deferred Tax Assets		
Alternative minimum tax credits	**172**	753
Regulatory liabilities	**815**	950
Investment tax credits	**68**	81
Reserve for bad debt	**177**	114
Asset retirement obligations	**545**	494
Accrued personal leave	**227**	215
Section 263(a) capitalized costs	**113**	82
Other	**605**	95
Total	**2,722**	2,784
Net accumulated deferred income tax liability	**26,060**	23,741

The components of the income tax provision are comprised of the following for the years ended June 30:

($000)	**2008**	2007	2006
Components of Income Tax Expense			
Current			
Federal	**1,158**	494	813
State	**395**	213	256
Total	**1,553**	707	1,069
Deferred	**2,594**	2,450	1,914
Income tax expense	**4,147**	3,157	2,983

Reconciliation of the statutory federal income tax rate to the effective income tax rate is shown in the table below:

	2008	2007	2006
Statutory federal income tax rate	**34.0%**	34.0%	34.0%
State income taxes, net of federal benefit	**4.0**	4.6	4.6
Amortization of investment tax credits	**(0.3)**	(0.5)	(0.5)
Other differences, net	—	(0.8)	(0.8)
Effective income tax rate	**37.7%**	37.3%	37.3%

In July 2006, the Financial Accounting Standards Board issued Interpretation No. 48, to clarify the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with Statement No. 109. Interpretation No. 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under Interpretation No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

The liability for unrecognized tax benefits expected to be recognized within the next twelve months has been presented in accrued taxes in the June 30, 2008 Consolidated Balance Sheet. The liability for unrecognized tax benefits not expected to be recognized within the next twelve months has been presented in asset retirement obligations and other in the June 30, 2008 Consolidated Balance Sheet. Interest and penalties on tax uncertainties are classified in income tax expense on the Consolidated Statements of Income.

The amount of unrecognized tax benefits, net of tax, which, if recognized, would impact the effective tax rate was $156,000. We accrued interest of $116,000 on unrecognized tax positions, of which $18,000 was recognized on the 2008 Consolidated Statement of Income. We expect our unrecognized tax benefits to decrease approximately $204,000 within the next twelve months, primarily due to filing a method change with the Internal Revenue Service. This decrease is related to timing differences and is not expected to have a material impact on our financial position, results of operations or effective tax rate. It is reasonably possible that there will be additional changes to the unrecognized tax benefits. However, it is not expected that such change will have a significant impact on our results of operations or financial position.

The following is a tabular reconciliation of our unrecognized tax benefits:

($000)

As of July 1, 2007	668
Gross increases	
Tax positions in prior period	1
Tax positions in current period	102
Gross decreases	
Tax positions in prior period	(102)
Lapse of statute of limitations	(16)
As of June 30, 2008	653

We file income tax returns in the federal and Kentucky jurisdictions. Tax years previous to June 30, 2005 and June 30, 2004 are no longer subject to examination for federal and Kentucky income taxes, respectively.

(5) Employee Benefit Plans

(a) Defined Benefit Retirement Plan We have a trusteed, noncontributory, defined benefit pension plan covering all eligible employees. Retirement income is based on the number of years of service and annual rates of compensation. The Company makes annual contributions equal to the amounts necessary to fund the plan adequately.

We adopted the disclosure and recognition provisions of Statement No. 158 effective June 30, 2007. The following table describes the total incremental effect of the adoption of Statement No. 158 on individual line items on the June 30, 2007 Consolidated Balance Sheet. This statement requires employers who sponsor defined benefit plans to recognize the funded status of a defined benefit pension plan on the statement of financial position and to recognize through comprehensive income the changes in the funded status in the year in which the changes occur. Statement No. 71 provides that regulated entities can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky is based on Financial Accounting Standards Board Statement No. 87, entitled Employers' Accounting for Pensions, which was amended by Statement No. 158. Regulators have been clear and consistent with their historical treatment of such rate recovery; therefore, we have recorded a regulatory asset representing the probable recovery of the portion of the change in funded status of the defined benefit plan that is expected to be recovered through future rates. The regulatory asset will be adjusted annually as prior service cost and actuarial losses are recognized in net periodic benefit cost.

($000)	Before application of Statement No. 158	Adjustments	After application of Statement No. 158
Prepaid pension cost	4,887	(3,935)	952
Regulatory assets – accrued pension	—	3,935	3,935

Our obligations and the funded status of our plan, measured at March 31, are as follows:

($000)	**2008**	2007
Change in Benefit Obligation		
Benefit obligation at beginning of year	**13,277**	12,696
Service cost	**749**	715
Interest cost	**746**	700
Actuarial gain (loss)	**(894)**	202
Amendment	**(3)**	—
Benefits paid	**(1,102)**	(1,036)
Benefit obligation at end of year	**12,773**	13,277
Change in Plan Assets		
Fair value of plan assets at beginning of year	**14,229**	13,067
Actual return on plan assets	**325**	698
Employer contributions	**745**	1,500
Benefits paid	**(1,102)**	(1,036)
Fair value of plan assets at end of year	**14,197**	14,229
Recognized Amounts		
Projected benefit obligation	**(12,773)**	(13,277)
Plan assets at fair value	**14,197**	14,229
Funded status	**1,424**	952
Net amount recognized as prepaid benefit costs in the Consolidated Balance Sheets	**1,424**	952
Items Not Yet Recognized as a Component of Net Periodic Benefit Costs		
Prior service cost	**(857)**	(940)
Net loss	**4,395**	4,875
Amounts recognized as regulatory assets	**3,538**	3,935

The accumulated benefit obligation was $11,679,000 and $12,191,000 for 2008 and 2007, respectively.

($000)	**2008**	2007	2006
Components of Net Periodic Benefit Cost			
Service cost	**749**	715	780
Interest cost	**745**	700	697
Expected return on plan assets	**(988)**	(995)	(931)
Amortization of unrecognized net loss	**250**	233	257
Amortization of prior service cost	**(86)**	(86)	(86)
Net periodic benefit cost	**670**	567	717
Weighted-Average % Assumptions Used to Determine Benefit Obligations			
Discount rate	**6.5**	5.8	5.8
Rate of compensation increase	**4.0**	4.0	4.0
Weighted-Average % Assumptions Used to Determine Net Periodic Benefit Cost			
Discount rate	**5.8**	5.8	5.8
Expected long-term return on plan assets	**7.0**	8.0	8.0
Rate of compensation increase	**4.0**	4.0	4.0

Our expected long-term rate of return on pension plan assets is based on our targeted asset allocation assumption of approximately 65% equity investments and approximately 35% fixed income investments and the market-related value of plan assets; market-related value of plan assets is based upon the fair value of the plan assets.

Plan Assets

Our pension plan weighted-average asset allocations as of the plan's measurement date (March 31) by asset category are as follows:

	2008	2007
Equity securities	**63%**	59%
Fixed income securities	**30**	37
Other	**7**	4
	100%	100%

Our equity investment target of approximately 65% includes allocations to domestic, international and emerging markets. Our asset allocation is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

We expect to contribute $677,000 to the pension plan in 2009.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

($000)

2009	732
2010	334
2011	822
2012	549
2013	2,183
2014 – 2018	6,112

Effective May 9, 2008, any employees hired on and after that date are not eligible to participate in our defined benefit pension plan. Employees hired after May 9, 2008 will receive a 4% contribution into their Employee Savings Plan account. This contribution is discretionary and subject to change with approval from our Board of Directors. Freezing the defined benefit plan for new entrants did not impact the level of benefits for existing participants.

The Statement of Financial Accounting Standards No. 106, entitled Employers' Accounting for Postretirement Benefits, and the Statement of Financial Accounting Standards No. 112, entitled Employers' Accounting for Postemployment Benefits, do not affect us as we do not provide postretirement or postemployment benefits other than the pension plan for retired employees.

(b) Employee Savings Plan We have an Employee Savings Plan ("Savings Plan") under which eligible employees may elect to contribute a portion of their annual compensation up to the maximum amount permitted by law. The Company matches 100% of the employee's contribution up to a maximum company contribution of 3.5% of the employee's annual compensation. Employees hired after May 9, 2008 will annually receive a 4% non-elective contribution into their Savings Plan account beginning July 1, 2008. This contribution is discretionary and subject to change with approval from our Board of Directors. For 2008, 2007, and 2006, Delta's Savings Plan expense was $281,000, $256,000 and $240,000, respectively. Effective July 1, 2008, the Company will match 100% of the employee's elective contribution up to a maximum matching contribution of 4.0%.

(c) Supplemental Retirement Agreement We sponsor a nonqualified defined contribution supplemental retirement agreement for Glenn R. Jennings, Delta's Chairman of the Board, President and Chief Executive Officer. Delta contributes $60,000 annually into an irrevocable trust until Mr. Jennings' retirement. At retirement, the trustee will make annual payments of $100,000 to Mr. Jennings until the trust is depleted. As of June 30, 2008 and 2007, the irrevocable trust assets are $250,000 and $203,000, respectively. These amounts are included in unamortized debt expense and other on the accompanying Consolidated Balance Sheets. Liabilities, in corresponding amounts, are included in asset retirement obligations and other on the accompanying Consolidated Balance Sheets.

(6) Dividend Reinvestment and Stock Purchase Plan

Our Dividend Reinvestment and Stock Purchase Plan ("Reinvestment Plan") provides that shareholders of record can reinvest dividends and also make limited additional investments of up to $50,000 per year in shares of common stock of the Company. Under the Reinvestment Plan we issued 18,653, 21,063 and 26,055 shares in 2008, 2007 and 2006, respectively. We registered 200,000 shares for issuance under the Reinvestment Plan in 2006, and as of June 30, 2008 there were 156,098 shares available for issuance.

(7) Note Receivable From Officer Related Party Transaction

Reflected in our 2007 and 2006 Consolidated Statements of Income is $62,000 and $24,000, respectively, of compensation related to the forgiveness of principal on a $160,000 loan made to Glenn R. Jennings, our

Chairman of the Board, President and Chief Executive Officer. We forgave $2,000 of the principal amount for each month of service Mr. Jennings completed through June 30, 2007. Mr. Jennings made monthly interest payments on the note based on an annual interest rate of 6%. We forgave the remaining balance of the note effective June 30, 2007.

(8) Notes Payable

The current available bank line of credit with Branch Banking and Trust Company is $40,000,000, of which $6,829,000 and $4,190,000 were borrowed having a weighted average interest rate of 3.21% and 6.32% as of June 30, 2008 and 2007, respectively. The maximum amount borrowed during 2008 and 2007 was $26,858,000 and $18,975,000, respectively. The interest on this line is determined monthly at the London Interbank Offered Rate plus .75% on the used bank line of credit. The annual cost of the unused bank line of credit is .125% and the bank line of credit extends through October 31, 2009.

(9) Long-Term Debt

In April, 2006, we issued $40,000,000 of 5.75% Insured Quarterly Notes that mature in April, 2021. Redemption of up to $25,000 annually will be made on behalf of deceased holders, up to an aggregate of $800,000 annually for all deceased beneficial owners. The 5.75% Insured Quarterly Notes can be redeemed by us beginning in April, 2009 with no premium.

In February, 2003 we issued $20,000,000 of 7.00% Debentures that mature in February, 2023. Redemption of up to $25,000 annually will be made on behalf of individual deceased holders, up to an aggregate of $400,000 annually for all deceased beneficial owners. The 7.00% Debentures can be redeemed by us through February, 2009 at a 1% premium. Subsequent to February, 2009, there is no premium to redeem the Debentures.

In May, 2006, we redeemed $23,672,000 aggregate principal amount of 7.15% Debentures due 2018.

In May, 2006, we redeemed $10,169,000 aggregate principal amount of 6 5/8% Debentures due 2023.

We amortize debt issuance expenses over the life of the related debt on a straight-line basis, which approximates the effective yield method. At June 30, 2008 and 2007, the unamortized balance was $5,123,000 and $5,511,000, respectively. Loss on extinguishment of debt of $2,539,000 and $2,729,000 included in the above has been deferred and is being amortized over the term of the related debt consistent with regulatory treatment.

The current portion of long-term debt of $1,200,000 represents the maximum aggregate principal amounts which can be paid to deceased beneficial owners. Therefore, the maximum maturities over the next five years are $1,200,000 each year. The Insured Quarterly Notes and Debentures do not have any sinking fund requirements.

Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined “events of default” which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders’ equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and

- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented.

(10) Fair Values of Financial Instruments

The fair value of our long-term debt is estimated using discounted cash flow analysis, based on our current incremental borrowing rates for similar types of borrowing arrangements. The fair value of our long-term debt at June 30, 2008 and 2007 was estimated to be $55,164,000 and $57,457,000, respectively. The carrying amounts in the accompanying Consolidated Balance Sheets as of June 30, 2008 and 2007 are $59,518,000 and $59,825,000, respectively.

The carrying amounts of our other financial instruments including cash equivalents, accounts receivable, notes receivable and accounts payable approximate their fair value.

(11) Operating Leases

We have no non-cancellable operating leases. Our operating leases relate primarily to well and compressor station site leases and are cancellable at our option. Rental expense under operating leases was $78,000, $78,000 and $88,000 for the three years ending June 30, 2008, 2007 and 2006, respectively.

(12) Commitments and Contingencies

We have entered into individual employment agreements with our four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments or lump sum payments and continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $3 million would be paid in addition to continuation of specified benefits for up to five years.

(13) Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and our transportation services. The Kentucky Public Service Commission’s regulation of our business includes setting the rates we are permitted to charge our regulated customers.

We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. The test year for the rate case was the twelve months ended December 31, 2006. The increased rates were requested to become effective May 20, 2007, but the implementation of the proposed rates was suspended until October 20, 2007.

During October, 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders’ equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

The Kentucky Public Service Commission has also approved a gas cost recovery clause, which permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs. Although we are not required to file a general rate case to adjust rates pursuant to the gas cost recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual gas costs were incurred. Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in four other cities we serve. In the other cities and areas we serve, either our franchises have expired, the areas served do not have governmental organizations authorized to grant franchises or the city governments do not require a franchise. We attempt to acquire or reacquire franchises whenever feasible.

Without a franchise, a city could require us to cease our occupation of the streets and public grounds or prohibit us from extending our facilities into any new area of that city. To date, the absence of a franchise has caused no adverse effect on our operations.

(14) Operating Segments

Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment, and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production. The regulated segment serves residential, commercial and industrial customers in the single geographic area of central and southeastern Kentucky. Virtually all of the revenue recorded under both segments comes from the sale or transportation of natural gas. Price risk for the regulated business is mitigated through our Gas Cost Recovery Clause, approved quarterly by the Kentucky Public Service Commission. Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict our demand. In addition, we are exposed to price risk resulting from changes in the market price of gas and uncommitted gas volumes of our non-regulated companies.

A single customer, Citizens Gas Utility District, provided $17,087,000, $9,843,000 and $15,422,000 of non-regulated revenues during 2008, 2007 and 2006, respectively, although there is no assurance that revenues from them will continue at these levels.

In 2008, 2007 and 2006, we purchased approximately 99% of our natural gas from interstate sources. We utilize Atmos Energy Marketing and M & B Gas Services to fulfill our interstate purchase requirements.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements. Intersegment revenues and expenses consist of intercompany revenues and expenses from intercompany gas transportation and gas storage services. Intersegment transportation revenues and expenses are recorded at our tariff rates. Revenues and expenses for the storage of natural gas are recorded based on quantities stored. Operating expenses, taxes and interest are allocated to the non-regulated segment. Segment information is shown in the following table:

($000)	**2008**	2007	2006
Operating Revenues			
Regulated			
External customers	**58,219**	53,499	65,343
Intersegment	**4,019**	3,643	3,498
Total regulated	**62,238**	57,142	68,841
Non-regulated			
External customers	**54,438**	44,669	51,904
Eliminations for intersegment	**(4,019)**	(3,643)	(3,498)
Total operating revenues	**112,657**	98,168	117,247
Operating Expenses			
Regulated			
Purchased gas	**33,493**	30,887	43,233
Depreciation	**4,053**	4,579	4,084
Other	**14,840**	13,538	13,292
Total regulated	**52,386**	49,004	60,609
Non-regulated			
Purchased gas	**43,389**	35,173	43,039
Depreciation	**118**	119	120
Other	**5,119**	4,547	4,219
Total non-regulated	**48,626**	39,839	47,378
Eliminations for intersegment	**(4,019)**	(3,643)	(3,498)
Total operating expenses	**96,993**	85,200	104,489
Other Income and Deductions, Net			
Regulated	**83**	134	228
Non-regulated	**—**	—	—
Total other income and deductions	**83**	134	228
Interest Charges			
Regulated	**4,556**	4,501	4,991
Non-regulated	**214**	146	(13)
Total interest charges	**4,770**	4,647	4,978
Income Tax Expense			
Regulated	**2,022**	1,349	1,235
Non-regulated	**2,125**	1,808	1,748
Total income tax expense	**4,147**	3,157	2,983
Net Income			
Regulated	**3,356**	2,422	2,234
Non-regulated	**3,474**	2,876	2,791
Total net income	**6,830**	5,298	5,025

Assets			
Regulated	**163,952**	154,029	150,541
Non-regulated	**6,863**	6,372	5,013
Total assets	**170,815**	160,401	155,554
Capital Expenditures			
Regulated	**5,564**	8,083	7,781
Non-regulated	—	—	—
Total capital expenditures	**5,564**	8,083	7,781

(15) Subsequent Events

In July, 2008, the Kentucky Public Service Commission approved in Case No. 2008-00062 our request to implement a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits and promote conservation awareness, and it also provides rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customers by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates will be adjusted annually to recover the costs incurred under these programs, including the reimbursement of margins on lost sales and the incentives provided to us.

(16) Quarterly Financial Data (Unaudited)

The quarterly data reflects, in the opinion of management, all normal recurring adjustments necessary to present fairly the results for the interim periods.

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss)	Basic and Diluted Earnings (Loss) per Common Share
Fiscal 2008				
September 30	**$ 12,404,170**	**$ (102,919)**	**$ (810,945)**	**$ (.25)**
December 31	**29,298,418**	**5,289,682**	**2,455,285**	**.75**
March 31	**48,396,125**	**9,884,436**	**5,421,108**	**1.65**
June 30	**22,558,404**	**592,537**	**(235,580)**	**(.07)**
Fiscal 2007				
September 30	$ 13,113,351	$ 274,217	$ (536,745)	$ (.16)
December 31	28,434,215	5,135,224	2,380,821	.73
March 31	41,022,436	7,140,820	3,665,329	1.12
June 30	15,598,389	417,782	(211,058)	(.07)

DELTA NATURAL GAS COMPANY, INC. AND SUBSIDIARY COMPANIES
VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED JUNE 30, 2008, 2007, and 2006

Column A	Column B	Column C Additions		Column D Deductions	Column E
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts – Recoveries	Amounts Charged Off Or Paid	Balance at End of Period
Deducted From the Asset to Which it Applies – Allowance for doubtful accounts for the years ended:					
June 30, 2008	$ 300,000	$ 599,345	$ 64,139	$ 498,484	$ 465,000
June 30, 2007	520,000	272,893	9,824	502,717	300,000
June 30, 2006	310,000	705,474	134,325	629,799	520,000

EXHIBIT 12

DELTA NATURAL GAS COMPANY, INC. AND SUBSIDIARY COMPANIES
COMPUTATION OF THE CONSOLIDATED RATIO OF EARNINGS
TO FIXED CHARGES

	2008	2007	2006	2005	2004
Earnings					
Net income	**$ 6,829,868**	$ 5,298,347	$ 5,024,635	$ 4,998,619	$ 3,838,059
Provisions for income taxes (a)	**4,146,900**	3,156,700	2,982,900	3,138,800	2,391,100
Fixed charges	**4,796,489**	4,673,261	5,006,608	4,494,445	4,424,777
Total	**$ 15,773,257**	$ 13,128,308	$ 13,014,143	$ 12,631,864	$ 10,653,936
Fixed Charges					
Interest on debt (a)	**$ 4,383,223**	$ 4,260,179	$ 4,704,075	$ 4,229,261	$ 4,158,988
Amortization of debt	**387,266**	387,082	273,533	236,184	236,789
One third of rental expense	**26,000**	26,000	29,000	29,000	29,000
Total	**$ 4,796,489**	$ 4,673,261	$ 5,006,608	$ 4,494,445	$ 4,424,777
Ratio of earnings to fixed charges	**3.29x**	2.81x	2.60x	2.81x	2.41x

(a) Interest accrued on uncertain tax positions, in accordance with Financial Accounting Standards Board Interpretation No. 48, is presented in income taxes on the 2008 Consolidated Statement of Income. This interest has been excluded from the determination of fixed charges.

Subsidiaries of the Registrant

Delgasco, Inc., Enpro, Inc. and Delta Resources, Inc. are wholly-owned subsidiaries of the Registrant, are incorporated in the state of Kentucky and do business under their corporate names.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 33-104301 of (1) our report dated August 28, 2008 relating to the consolidated financial statements and financial statement schedule of Delta Natural Gas Company, Inc. and subsidiaries (the Company) which report expressed an unqualified opinion on the Company's consolidated financial statements and financial statement schedule and included explanatory paragraphs regarding the Company's adoption of new accounting standards in 2008 and 2007 and (2) our report dated August 28, 2008 relating to the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Delta Natural Gas Company, Inc. for the year ended June 30, 2008.

/S/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 28, 2008

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn R. Jennings, certify that:

1. I have reviewed this annual report on Form 10-K of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 29, 2008

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John B. Brown, certify that:

1. I have reviewed this annual report on Form 10-K of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 29, 2008

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

/s/Glenn R. Jennings

Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

August 29, 2008

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

/s/John B. Brown

John B. Brown
Chief Financial Officer, Treasurer and Secretary

August 29, 2008