COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

APPLICATION OF DELTA NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF RATES	)))	CASE NO. 2010-00116

DIRECT TESTIMONY OF

GLENN R. JENNINGS

April 23, 2010

AFFIDAVIT

The affiant, Glenn R. Jennings, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2010-00116 in the Matter of: Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional examination as may be appropriate at the hearing in Case No. 2010-00116 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

Glenn R. Jennings
GLENN R. JENNINGS

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me by Glenn R. Jennings, this the 21st day of April, 2010.

My Commission Expires: 6/20/12

Emily P. Bennett
Notary Public, State at Large, Kentucky

Q. Please state your name and business address.

A. Glenn R. Jennings, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391.

Q. What is your present employment?

A. I am presently employed as Chairman of the Board, President and Chief Executive Officer of Delta Natural Gas Company, Inc.

Q. For what period of time have you been so employed?

A. I was employed by Delta as Treasurer in 1979. I was appointed Vice President - Finance and Treasurer in 1982; Executive Vice President, Treasurer and Chief Operating Officer in 1983; President, Treasurer and Chief Executive Officer in 1985; President and Chief Executive Officer in 1988 and Chairman of the Board, President and Chief Executive Officer in 2005.

Q. Would you briefly describe your education and professional experience?

A. I attended Berea College, Berea, Kentucky, from 1969 to 1972, receiving a B.S. in Business Administration. I have also attended two graduate schools working toward an M.B.A. I am a Certified Public Accountant in the states of Kentucky and Ohio. From 1972 to 1973, I was employed by Ford Motor Company in Cincinnati, Ohio as a production supervisor in a plant that manufactured automotive transmissions. I was employed by the accounting firm of Arthur Andersen & Co. in its Cincinnati, Ohio office from 1973 to 1977, specializing in the utility area. From July, 1977 to January, 1979, I was employed by Berea College as Internal Auditor and Assistant to the Vice President for Finance, during which time I prepared rate cases and testified before the Public Service Commission several times. Since January, 1979, I have been employed by Delta.

I have appeared before the Public Service Commission on numerous occasions on Delta's behalf.

I served 11 years on the Board of Directors of the Kentucky Gas Association (President in 1991-1992). I am a past Chairman (1997-1998) of the Board of Directors of the Southern Gas Association and serve on the Board of Directors of the American Gas Association (Chairman of Small Member Council and past Chairman of the Audit Committee).

Q. Generally what are your duties with Delta?

A. As Chairman of the Board, President and Chief Executive Officer, I have responsibility for all areas of Delta. I supervise the officers of the Company who report to me and are responsible for each of their respective segments of the Company.

Q. Mr. Jennings, will you please summarize for the Commission the historical development of Delta's business?

A. Certainly. Delta is a Kentucky corporation with its principal office at 3617 Lexington Road in Winchester, Kentucky. In 1950, Delta completed its first distribution system, which served approximately 300 customers in Owingsville and Frenchburg. Delta expanded its business until 1977 when it was serving 11,000 customers in relatively small communities in central Kentucky. At that time Delta's only source of gas supply was the interstate system and the Company was not large enough to attract the capital sufficient to continue to provide a high degree of service to our customers. Therefore, the decision was made to expand our business by acquiring gas systems in the gas producing regions in southeastern Kentucky. In October, 1977, we acquired Gas Service Company, Inc., Cumberland Valley Pipe Line Co. and Laurel Valley Pipe Line Company. These companies operated the distribution systems in London, Pineville, Middlesboro, Williamsburg and part of Barbourville, the transmission lines linking the towns, except London, and related gathering lines and gas storage facilities. At that point we began serving an additional 8,500 customers and began utilizing locally produced natural gas and gas storage facilities. In January, 1981, we acquired the assets of Peoples Gas Company of Kentucky, a subsidiary of The Wiser Oil Company, which added approximately 8,700 customers in Corbin, Barbourville, Manchester, Oneida and Burning Springs. In January, 1982, we purchased approximately 57 miles of transmission lines from Wiser which run generally from Manchester to Corbin and London. In 1989, we leased the TranEx pipeline, a 43 mile 8 inch diameter pipeline which extends from Manchester to Richmond, and began operating it as a part of our transmission system. In 1995-1996, we developed and began operating an underground storage field in Bell County. We purchased the TranEx pipeline in 1997. Delta has continued to successfully expand its distribution systems by extending to new areas such as Beattyville in 1992. Delta expanded into Fayette County in 1997 and also acquired the North Middletown distribution system in Bourbon County as well as Annville Gas & Transmission in Jackson County. We also purchased the Mt. Olivet gas system, located in Robertson and Mason Counties, in 1999.

Delta has thus grown to a system of approximately 37,000 customers in primarily rural areas of Kentucky with 5 district offices, two warehouses and approximately 2,500 miles of transmission, distribution, service and gathering pipeline in 23 counties in central and southeastern Kentucky. This includes transmission lines that interconnect with

Richmond, Berea, Manchester, London, Corbin, Middlesboro, Barbourville, Pineville and Williamsburg. In addition, transmission lines interconnect the other communities we serve with each other and/or the sources of gas. The gathering systems are located in Bell, Knox, Whitley and Clay counties in the vicinity of production wells. Delta owns, operates and maintains service lines as well.

Delta is a relatively small, independent, investor-owned utility headquartered in Winchester. Our system is mainly in smaller Kentucky communities or rural areas, and there are no large concentrations of customers. We serve an area in central and southeastern Kentucky that was not otherwise served and provide service to small, rural areas in eastern Kentucky. We continue to consider expansion into eastern Kentucky areas, including acquisition of smaller systems there. We are the only stand-alone, publicly owned, Kentucky-based utility among the larger utilities in the state. We must meet all requirements for a public company, including compliance with the Sarbanes-Oxley Act of 2002, despite our smaller size. Thus, we are faced with a significant challenge to control the upward pressure on rates while still providing our customers with a high degree of service as well as maintaining an adequate return to our shareholders so that we can continue to raise the capital needed. Our general overhead is thus only spread over our rural Kentucky-based operations. Reduced customer count and customer conservation thus has a significant negative effect on our financial results.

Q. Mr. Jennings, are you sponsoring any of the Filing Requirements in this proceeding?

A. Yes, I am sponsoring the following Filing Requirement:

- Reason for a rate adjustment, Section 10(1) (a) 1 under Tab 1

Q. Mr. Jennings, please tell the Commission the reason an adjustment in rates is required.

A. In this filing, our rate base, capital and operating costs reflect current and known levels. We based our proposed rates on data for the test year ended December 31, 2009, or as of the end of the test year, and included known facts which are reflected as adjustments consistent with our last rate case. We have proposed a rate design similar to that approved by the Commission in our last case with adjustments to reflect our updated cost of service study as well as current market conditions.

Our last rate filing in 2007 utilized a test year ending December 31, 2006. Thus, by the time rates are expected to be implemented from this case, almost four years will have passed since the test year end for the last case. The rates requested in this filing will update our existing rates to reflect current levels of rate base, operating expenses, taxes, depreciation and interest as well as to recover a reasonable return on equity investments. We have adjusted depreciation expense for the depreciation rates recommended in the depreciation study required for this filing, which is included in the testimony of William Steven Seelye in this case.

Delta has experienced increased costs such as for health care and pension expense since 2006. We have made capital expenditures since 2006 to replace and improve portions of our system. We have also experienced reductions in customer usage since our prior rate case as customers have continued to conserve as well as replace equipment with more fuel efficient equipment. Delta has also continued to experience a decline in customer count as some customers have switched to other energy sources. The national trend of declining consumption is consistent with Delta's experience since our last rate case. Our margin on sales (revenues minus gas costs) and earned return on equity in the test year in this rate filing, the twelve months ended December 31, 2009, are less than those results contemplated at the conclusion of Case No. 2007-00099. Our earned return on equity for the test year was only about 5.1%.

Q. Mr. Jennings, can you comment upon Delta's competitive environment today and what impact this has upon rate design and other marketing considerations?

A. Yes, I can. We have competition in our service area from many alternate energy sources, including electricity, coal, oil, wood, propane and other natural gas suppliers. We compete directly with several electric utilities, including Kentucky Utilities, and various RECCs and municipal systems.

Our larger volume customers with alternate fuels available in the case of interruption could switch to those alternate fuels such as oil or propane at any time. Such customer losses place a greater burden on Delta and all remaining customers. It is advantageous to Delta, and Delta's smaller volume customers, to retain the larger volume load customers because of their contribution to the recovery of fixed costs. We also need to be competitive for new industrial prospects, since they too will benefit all our customers.

On and off-system transportation are a significant component of our total throughput. We have been physically bypassed in some instances and threatened in others. Thus competitive transportation rates are very important to us. Maintaining our present interruptible transportation rates as well as competitive off-system transportation rates should help to retain our larger volume customers as well as attract new ones.

Q. In developing the proposed rates in this case, how has Delta considered its cost of service study?

A. The cost of service study determined the cost of service and return on rate base for each customer class. In designing our rates we considered the cost of service study, as well as the principles of rate continuity, gradualism and customer acceptance. This should help to keep Delta's rates in its service areas attractive for economic development.

Q. Mr. Jennings, how do the transportation revenues reflected in this rate filing benefit Delta's sales customers?

A. Delta's sales customers benefit from transportation since the revenue provided by on-system and off-system transportation service reduces the revenue requirement otherwise required from Delta's other customers. Delta continues to try to maximize transportation deliveries for others. Our transportation business has increased in the past several years. We are concerned about whether the test year level of transportation revenues will continue in the future, since transportation volumes can vary as continued deliveries are dependent upon many variables, including weather, overall economic conditions, producers' production capabilities, the level of end-user operations, supply needs, system capabilities, federal regulations and bypass.

Q. Could you comment on Delta's proposal for a Pipe Replacement Program?

A. Yes, I can. As set forth in the testimony of John B. Brown, Delta proposes a Pipe Replacement Program ("PRP") as a new tariff. This proposal is similar to tariffs enacted recently for Columbia of Kentucky and pending approval for Atmos. The purpose is to adjust annually for the costs of replacing older pipe in Delta's system that requires replacement due to age and condition. This will provide for enhanced safety and service to customers on our system. The pipe replacements are required and this will allow a method other than a costly general rate case to recover annual revenues related to the costs of such replacements.

Q. Please comment on Delta's proposal to modify its Gas Cost Recovery mechanism to provide for recovery of the gas costs reflected in uncollectible accounts.

A. As set forth in the testimony of John B. Brown, Delta is requesting to modify its Gas Cost Recovery ("GCR") mechanism to provide for recovery in the future of uncollectible expense associated with the gas cost component of Delta's rates. When our customers do not pay their bills, the gas component is lost as the gas has been purchased by Delta but not recovered due to uncollectible accounts. This provides a means to collect such gas costs through Delta's GCR mechanism, which is adjusted quarterly to reflect changes in gas costs. This will ensure that Delta's rates reflect all gas costs, including uncollectible gas costs. Our proposal is similar to changes recently approved by the Commission for Columbia of Kentucky and pending for Commission approval in Atmos' recent rate case.

Q. Why is Delta not proposing a rate stabilization mechanism in this filing as it has proposed in prior rate filings with the Commission?

A. Although we firmly believe a Customer Rate Stabilization ("CRS") mechanism as we proposed in our last rate case is worthwhile and in our customers' best interests, there is a case before the Kentucky Supreme Court, File No.2009-SC-000143-D, that could result in further clarification of the Commission's authority to approve such a CRS mechanism. Thus we believe that timing and the pending nature of issues in this area require that we not propose such a CRS mechanism in this filing and instead await the outcome of the Kentucky Supreme Court proceeding. We do plan to consider filing such a CRS mechanism in the future when appropriate. We have participated in collaborative meetings with interested parties, including the Attorney General's office, to discuss our proposed CRS mechanism. We will continue to consider such a mechanism through appropriate legislative as well as regulatory solutions.

Q. Mr. Jennings, what impact would such a Customer Rate Stabilization mechanism as Delta has suggested in prior rate cases have on Delta's customers?

A. We believe a rate stabilization tariff could significantly reduce the costs now required to adjust rates because of the simplified annual filing procedure. It could stabilize rate adjustments by providing for annual adjustments in rates and by keeping rates current with smaller adjustments each in keeping with the principle of gradualism. It would prevent continued potential over-earning situations since, if earnings were to exceed allowed amounts, then rates would be adjusted downward for the next year to rectify this. It would also provide for rates to be adjusted annually to reflect the impacts of conservation and efficiency gains by customers, thus better aligning Delta's and our customers' interests. There would be no impact on Delta's required return on equity because the mechanism would not change the return on equity approved in the last general rate case. Delta, like all jurisdictional utilities in Kentucky, has the ability now to file general rate cases as frequently as needed to request adjustments in rates. In the absence of such a CRS mechanism, Delta now finds it necessary to make this filing to increase its rates. If a CRS mechanism had been in effect since Delta's last rate case, smaller annual adjustments should have resulted, at a reduced cost to Delta's customers of such annual adjustments. Thus we continue to advocate the adoption at the appropriate time, either by the Commission or by the General Assembly, of a Customer Rate Stabilization mechanism as has been approved in a growing number of states.

Q **Do you agree with the return on common equity as recommended by Dr. Blake?**

A. Yes. Delta is small in comparison to major utilities, yet, as an independent, investor-owned company, it must compete in the same financial markets for its new capital. Delta must be able to raise common equity to enable it to continue to issue long-term debt securities. Also, common equity issuance is a necessity in order to be able to continue our required short-term lines of credit, which is now necessary to meet summer construction and storage injection needs.

We are in contact with brokers, analysts, investment bankers, investors, shareholders and market makers on a routine basis to discuss Delta and their concerns as they relate to Delta. Their primary concerns are the stability of dividends, future growth in dividends and stock value and maintenance of an adequate return on common equity to provide for these items. In order to be able to issue and sell debt and equity securities on fair terms, we must be able to maintain reasonable retained earnings over and above our dividend payments to shareholders.

As Dr. Blake states in his testimony, Delta's earnings since our last rate case have been inadequate. This trend continued during 2009 and Delta's December 31, 2009, net income provided an inadequate return on common equity, well below Delta's authorized return. Delta's requested return is fair and reasonable and will produce a reasonable yield to investors and allow us to continue our dividends. Such a return should thus strengthen the shareholders' confidence in investing in Delta's common stock. This will also provide Delta the opportunity to continue to fulfill its future capital needs in the common equity markets at a fair cost to both customers and stockholders.

We have asked for a slightly higher return than some other jurisdictional utilities have sought in recent filings with the Commission. We believe this is reasonable due to Delta's smaller size, rural eastern Kentucky service area and higher relative risk.

Q. **Could you please review Delta's current financial condition and financing needs?**

A. Yes. Our earnings for calendar 2009, the test year, are not adequate. Financial indicators such as return on common equity and payout ratio indicate that Delta's financial condition needs to improve. We must improve earnings to be able to continue our dividend and we must be able to continue our dividend in order to raise future equity capital effectively.

We utilize short-term debt, along with internally generated cash flow from operations, to meet our construction expenditure needs. We periodically repay these short-term borrowings as capital markets permit and as our needs dictate. In 2006, we refinanced some of our long-term debt and short-term debt with the issuance of long-term debt.

Delta had borrowed approximately $12 million under its short-term line of credit as of the end of the test period, and our current credit line must be renewed in June, 2011. The continuing availability of this line of credit is closely tied to our ability to refinance those borrowings from time to time. Our continuing ability to raise debt and equity capital, and thus to be able to continue to finance our construction expenditures, is a direct result of our financial stability. An expedient approval of the rates as requested would be fair to both Delta's shareholders and customers and would help to keep our cost of capital as low as possible.

Q. Please describe Delta's response to industry changes that have taken place in the past few years.

A. Delta deals with industry change with the best interests of its customers in mind. Prior to deregulation of natural gas wellhead prices in the 1980s, Delta began transporting for larger volume customers, producers and off-system customers and those additional transportation revenues helped to keep our other rates lower. We have had a mix of supplies from producers, marketers, pipelines and our own supplies and this has helped to balance our supplies and prices and keep our gas costs as low as possible. In order to further respond to the changes, we acquired and developed the Canada Mountain underground natural gas storage field in Bell County, Kentucky. This storage field is a significant factor in meeting our seasonal supply needs. We have continued to seek ways to increase our transportation business to help keep our rates as low as possible to our customers.

We continue to strive to improve productivity and efficiency wherever we can. For example, in fiscal 1999 we had 183 full-time employees who maintained our annual system throughput of approximately 9 bcf. By comparison, in 2009 we had 154 full-time employees maintaining a system throughput approaching 18 bcf. Thus we maintain a system throughput that has increased since that time by approximately 100%, and we are doing so with approximately 16% fewer employees. Our test year in our prior rate case started well over four years ago and inflation has increased by about 9% since that time.

We have a very high level of customer satisfaction. We strive for excellence in customer service, with 100% of our meters being read using automated meter reading devices to provide efficiency, speed, accuracy and actual reads each month for customer bills. Our customer calls are dispatched by Kentucky-based employees in our service area, with knowledge of our customers and service area. We have a well trained and experienced work force of Kentucky-based operations providing our excellent service. Customers make their payments personally to our district offices, or by mail or through direct bank withdrawals for their convenience. Our budget billing program allows customers to smooth out their bill payments. We own, maintain, operate and replace as needed all customer service lines, so our customers do not have that direct responsibility. We try our very best to provide same day service to our customers to meet their schedules and needs in an efficient and effective manner. We also assist in our service area with economic development efforts and work to ensure that our systems are extended to any areas possible to assist in further development that is pursued.

Q. Does this conclude your testimony at this time?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF RATES	)))	CASE NO. 2010-00116

DIRECT TESTIMONY OF

JOHN B. BROWN

AFFIDAVIT

The affiant, John B. Brown, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2010-00116, in the Matter of: An Adjustment of Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional examination as may be appropriate at the hearing in Case No. 2010-00116 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

John B. Brown

JOHN B. BROWN

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me by John B. Brown, this the 21st day of April, 2010.

My Commission Expires: 6/20/12

Emily P. Bennett

Notary Public, State at Large, Kentucky

Q. Please state your name and business address.

A. John B. Brown, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391.

Q. What is your present employment?

A. I am an accountant, presently employed by Delta as its Chief Financial Officer, Treasurer and Secretary.

Q. For what period of time have you been so employed?

A. I was employed by Delta as Manager – Accounting & Finance in April of 1995. I was appointed Controller in March of 1999 and promoted to Vice President – Controller and Assistant Secretary in November, 2005. I was named Chief Financial Officer, Treasurer and Secretary in May, 2007.

Q. Would you briefly describe your education and professional experience?

A. I attended Asbury College, Wilmore, Kentucky, from 1985 to 1989, receiving B.A. degrees in accounting and business management with a minor in computer science. I received an MBA degree from the University of Kentucky in 2000. I am a Certified Public Accountant in the state of Kentucky. I was employed by the accounting firm of Arthur Andersen LLP in its Louisville, Kentucky office from 1989 to 1995, specializing in the utility area. Since April, 1995, I have been employed by Delta.

Q. Generally what are your duties with Delta?

A. As Chief Financial Officer, Treasurer and Secretary, I am responsible for finance, budget, accounting, tax, internal audit, information technology, accounts payable, human resources, rates, corporate governance and investor relations.

Q. Are you generally familiar with the business affairs of Delta?

A. Yes, I am.

Q. Have you previously provided testimony to the Commission?

A. Yes, I have been a witness on behalf of Delta in the following proceedings:

- Case No. 2008-00062 Application of Delta Natural Gas Company, Inc. for Approval of a Customer Conservation/Efficiency Program and Demand Side Management Cost Recovery Mechanism.
- Case No. 2007-00089 Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates.
- Case No. 2004-00067 Adjustment of the Rates of Delta Natural Gas Company, Inc.
- Case No. 1999-176 Adjustment of Rates of Delta Natural Gas Company, Inc.
- Case No. 1997-066 Adjustment of Rates of Delta Natural Gas Company, Inc.

Q. Please briefly summarize the scope of your testimony.

A. In my testimony, I sponsor all of the rate application amounts from the books and records of the Company. In that regard I am sponsoring the following filing requirements:

• Most Recent Annual Reports	Section 10(1)(a)2	Tab 2
• Articles of Incorporation	Section 10(1)(a)3	Tab 3
• Limited Partnership	Section 10(1)(a)4	Tab 4
• Certificate of Good Standing	Section 10(1)(a)5	Tab 5
• Certificate of Assumed Name	Section 10(1)(a)6	Tab 6
• Describe and Explain Adjustments	Section 10(6)(a)	Tab 20
• Testimony of Witnesses – Gross Revenue greater than $1,000,000	Section 10(6)(b)	Tab 21

• Testimony of Witnesses – Gross Revenue less than $1,000,000	Section 10(6)(c)	Tab 22
• Revenue Requirements Determination	Section 10(6)(h)	Tab 27
• Reconcile Rate Base & Capitalization	Section 10(6)(i)	Tab 28
• FERC and FCC Audit Reports	Section 10(6)(l)	Tab 31
• FERC Form 1 and Form 2	Section 10(6)(m)	Tab 32
• Stock or Bond Prospectuses	Section 10(6)(p)	Tab 35
• Annual Reports to Shareholders	Section 10(6)(q)	Tab 36
• SEC Reports (10Ks, 10Qs, and 8Ks)	Section 10(6)(s)	Tab 38
• Local Telephone Exchange Companies	Section 10(6)(v)	Tab 41
• Financial Statements with Adjustments	Section 10(7)(a)	Tab 42
• Capital Construction Budget	Section 10(7)(b)	Tab 43
• Pro Forma Adjustment – Plant	Section 10(7)(c)	Tab 44
• Pro Forma Adjustments – Operating	Section 10(7)(d)	Tab 45

Q. Do you adopt the Filing Requirements you just identified, and do you make them a part of your testimony?

A. Yes.

Q. Regarding Tab 2, are Delta's annual reports on file with the Kentucky Public Service Commission?

A. Yes, Delta's annual reports, including the annual report filed under the FERC Form 2 format for the calendar year 2009 are on file with the Kentucky Public Service Commission in accordance with KAR 5:006, Section 3(1).

Q. Have you provided a complete description and quantified explanation for all proposed adjustments, as instructed in Section 10(6)(a)?

A. Yes. In Tab 20, I have described each adjustment that is shown in Tab 42 for FR Section 10(7)(a). Further detail for certain of the adjustments are found in Tab 27 for FR 10(6)(h) as discussed below. The attached workpapers, together with the description of the adjustments, provide the description and explanation of proposed adjustments.

Q. Please explain Tab 27, the determination of the revenue requirement.

A. Tab 27 contains the nine schedules of the revenue requirement study and supporting workpapers. Schedule 2 shows the calculation of revenue at present rates and contains the bill frequency analysis. The supporting workpapers present the calculation of the proposed adjustments included in the revenue deficiency study.

Q. What is the amount of the revenue deficiency?

A. The amount of revenue deficiency to be recovered by proposed rates is $5,315,428 and is shown in Schedule 1. The deficiency of $5,315,428 is calculated by comparing the total cost of service to the revenues at present rates. This revenue deficiency requires a rate increase of approximately 11.54% of normalized revenues. Schedules 2 through 9 present the components of the cost of service.

Q. Briefly describe Schedules 2 through 9.

A. These Schedules present more detail related to the test year actual data and adjustments which were made to arrive at the revenue deficiency.

Q. Please explain Schedule 2.

A. Schedule 2 shows actual billing determinants for the twelve months ended December 31, 2009 and the proposed adjustments to the billing determinants. Schedule 2 also shows the calculation of gas cost using Delta's current GCR effective January 25, 2010. The amount of gas cost recovery included in present rates is applied to the adjusted volumes.

Q. Does Schedule 2 include a proposed increase due to miscellaneous revenue?

A. No. We are not proposing any changes in our current reconnect charge ($60.00), bad check charge ($15.00) or collection charge ($20.00).

Q. Have you included an adjustment for year end customers in Schedule 2?

A. No. While William Steven Seelye prepared a calculation of Number of Customers at the End of the Test Year in Section V of his testimony, we believed that it was not appropriate to apply it to the test year, in light of our history of shrinking customer base over the last five years as shown in Exhibit JB 1. Not only does the exhibit show that our number of retail customers has decreased, but so has our annual usage and usage per customer.

Q. Please explain Schedule 3.

A. Schedule 3 shows actual operation and maintenance expenses for the twelve months ended December 31, 2009 and the pro forma adjustments to reflect changes which were known and measurable with reasonable accuracy during the preparation of this filing. To ensure fair, just and reasonable rates based on the historical test period, this filing includes only those operating expenses which the Company is actually incurring or will incur. The source for the actual test year costs is the Company's books and records.

Q. Please briefly describe these adjustments.

A. The only O & M adjustment which increases test year expenses is the bad debt adjustment. In 2008 a reserve was booked in Delta's uncollectible account to cover uncollectible risk arising from some non-regulated customers. In 2009 that entry was reversed to transfer the reserve to the subsidiary's books. The adjustment is necessary to correctly state test year regulated bad debt expense, less an allocation for the Gas Cost Collection Charge, which we are proposing to collect separately through the GCR mechanism. The payroll adjustment normalizes for wage increases given July 1, 2009. Accounts disallowed in Case No. 2004-00067 are removed. The estimated rate case expense is being amortized over three years, which is consistent with the treatment of this item in our last two rate cases.

Q. Please describe Schedule 4.

A. Schedule 4 shows depreciation and amortization expense. Actual expenses are adjusted to reflect the test year end level of plant investment. The rates used are those from the Depreciation Study presented by Mr. Seelye in his testimony.

Q. What adjustments were made to taxes other than income taxes?

A. Schedule 5 shows taxes other than income taxes. Payroll taxes were adjusted to correspond to the adjusted wage levels.

Q. Please describe Schedule 6.

A. Schedule 6 shows rate base and required return. The total rate base is the investment attributable to Delta's system only, excluding Delta's subsidiary companies. Cash requirements are included at one-eighth of operation and maintenance expenses excluding purchased gas cost. Prepayments, materials and supplies and gas in storage were included using a 13 month average which is consistent with the treatment in our last rate case.

Q. Please explain Schedule 7.

A. Schedule 7 shows income tax expense. The tax expense is calculated based on the required after tax equity return and a combined tax rate of 37.960 percent. The 37.960 percent tax rate is the result of combining the 34 percent federal rate with the state income tax rate of 6 percent as computed on Schedule 7.1.

Q. Please describe Schedule 8.

A. Schedule 8 shows the calculation of Delta's overall cost rate for capital which is 8.677 percent.

Q. **Delta has adopted new accounting standards related to pension accounting since its last case. Is test year pension expense or equity inconsistent with previous cases due to these changes?**

A. No. We recorded a regulatory asset representing the adjustment to the pension asset in recognizing the funded status of the plan. This accounting recognizes the fact that the new accounting standards had no impact on how Delta recovers pension costs in rates therefore its adoption should have no impact on Delta's net income or equity balances which are used as a basis for ratemaking.

Q. What cost rates are used for debt capital in the calculation of the overall cost of capital?

A. Delta's embedded cost of long-term debt as of the end of December, 2009, which is 6.83 percent, was used for long-term debt. The current rate of 2.04 percent as of April 1, 2010 was used for short-term debt.

Q. What is the requested cost of equity capital?

A. I used 12% on the adjusted capital structure as recommended by Dr. Martin J. Blake in his testimony.

Q. Please explain Tab 28, the reconciliation of rate base and capital used to determine its revenue requirements required by Section 10(6)(i).

A. Tab 28 Section 10(6)(i) refers to the reconciliation in Tab 42 on Schedule 1 for Section 10(7)(a).

Q. Regarding Tab 39, did Delta have any amounts charged or allocated to it by an affiliate or general or home office or paid any monies to an affiliate or general or home office during the test period or during the previous three (3) calendar years?

A. No.

PIPE REPLACMENT PROGRAM

Q. Please explain the objective of the proposed Pipe Replacement Program mechanism.

A We propose this mechanism because we believe it supports the Company's historic legacy of operating a safe and reliable system in Kentucky while maintaining excellent customer service. The Pipe Replacement Program ("PRP") mechanism would, in essence, provide a mechanism to recover more currently the cost of replacing all existing bare steel within the Company's system. The PRP would also include replacement of service lines, curb valves, meter loops, and any mandated relocates. Delta will replace deteriorating main and service pipe and enhance the safety of its system by ensuring replacement of facilities with new, longer lasting and safer materials. Annual replacement cost may vary from year-to-year depending on size and location of the pipe replaced.

Q. Why does Delta need a Pipe Replacement Program?

A. Delta's gas system still contains bare steel mains along with the associated service lines, service risers, meters and appurtenances needed to deliver natural gas to our customers. Many of these facilities have reached the point in their service lives where it is no longer cost effective to continue to repair them due to accelerated corrosion rates. Since all of these replacement projects generate incremental costs for the Company with no incremental revenues, the only method currently available to the Company to recover the costs it incurs for pipe replacement is through costly traditional rate cases. Delta's PRP will improve public safety and reliability of service for our customers. The PRP mechanism will align our customers' interests of safety and reliability with the shareholders' interests of return on investments. Delta plans to use a systematic approach to replacement that will reduce inconvenience to the public, require fewer unplanned disruptions to traffic for emergency repair, and improve coordination with local and state highway agencies. Public safety will be our highest objective and those pipe sections that need prompt attention will be given priority. We believe the PRP mechanism will provide benefits to Delta as well as to the customer by avoiding the costly and resource-intensive process necessary to review adjustments through the traditional rate case process replacing it instead with a simple, straightforward and financially transparent process. The PRP will allow the Company to earn a more timely return on the incremental investment, including incurred overhead expenditures, and be reimbursed for related expenses including incremental depreciation expense and ad valorem taxes while avoiding the resource commitment and expense required by traditional rate cases. The annual PRP filings made by the Company are streamlined so as to avoid the majority of legal and other expenses inherent in traditional rate cases while maintaining an appropriate level of rigor and review. In the absence of such a mechanism, the Company would find it necessary to:

1) file traditional rate cases more frequently,

2) reduce its level of incremental capital investment (thus prolonging the time required to replace the bare steel pipe), or

3) some combination of 1 and 2.

Q. Please describe in more detail the pipe replacement components that Delta proposes to include in its PRP.

A. Delta proposes to include in the PRP all of the planning, design, replacement construction, investment and retirement costs related to the replacement of the following categories of bare steel (whether or not cathodically protected), cathodically unprotected coated steel, and ineffectively coated steel (whether or not cathodically protected). Also, as a part of the PRP Delta proposes to include all of the planning, design, replacement construction, investment and retirement costs related to the replacement of all piping from the main to the customer's meter including curb valves, service risers, meter sets and all other related appurtenances that do not meet current material and construction standards or pose other operational issues. Finally, Delta will be taking steps to ensure that the newly installed facilities are appropriately designed and sized. This may necessitate in certain circumstances the replacement of facilities other than bare steel mains and services and those planning, design, replacement construction, investment and retirement costs will be included in the PRP as well. We are replacing all service lines regardless of material, that do not meet current material and construction standards, where compliance with current material and construction standards are not practical to determine, and where failing to do so will create additional legacy operating and maintenance costs. Generally, services are replaced at the same time we replace the main piping or in those cases where individual service lines are replaced on a random basis due to emergency leakage, damage, or other relocation or replacement requirements. In most cases service lines are replaced with the same plastic material as used for mains. At times we are mandated to relocate our facilities without reimbursement. All of these costs are included in the PRP.

Q. Please describe the manner in which Delta has historically addressed replacement of its bare steel pipe.

A. Delta has been replacing and retiring bare steel pipe in its system since the 1970's. Delta replaces pipe segments based on analyses of the segment's historical leak rate. Delta attempts to identify the worst likely performing segments and replaces those each year. Delta also replaces short segments of main and service pipe on an emergency basis when it is determined that an effective repair cannot be made.

Q. What are the main causes of leaks on bare steel pipe?

A. The number one cause of leaks on bare steel pipe is galvanic corrosion. Excluding excavation damage, approximately 69 percent of all leaks repaired on Delta's system during 2009 were caused by corrosion.

Q. How does Delta manage or classify leaks and prioritize repairs?

A. Delta classifies each leak found according to the rules outlined in our Operations and Maintenance Manual. Leaks are graded according to severity, Grade 1 being the most severe, through Grade 3. Grade 1 leaks represent an existing or probable hazard to persons or property that requires immediate repair or continuous action until the conditions are no longer hazardous. A Grade 2 leak is a leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard. Grade 3 leaks are non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

Q. What types of materials will be used to replace the bare steel?

A. The majority of replacement piping will be polyethylene plastic where the system pressures will allow it to be used. All of the other replacement piping will be cathodically protected coated steel pipe.

Q. Will corrosion leaks on bare steel increase in the future and does this increase the risk to public safety?

A. Yes, corrosion leaks on bare steel main will increase in the future. The likelihood of leaks occurring increases as the corrosion becomes more general and severe on the pipe wall. The combined effects of aging pipe and continuous corrosion increases the potential of an incident occurring. Each leak found on the system increases the risk to public safety.

Q. Are you saying Delta's system is unsafe?

A. No. Delta's gas system is safe. Leakage rates are managed utilizing the leak grading system described above. All leaks are either repaired when found or monitored on a predetermined schedule to maintain a high level of public safety. However, with the amount of aging bare steel pipe in our system and the continuous corrosion threat that exists, public safety is enhanced with Delta having a PRP mechanism that encourages a systematic, accelerated approach to bare steel pipe replacement.

Q. Will Customers enjoy benefits in addition to enhanced public safety?

A. Yes. Any reduction in line losses, previously attributable to the bare steel pipe being replaced, will automatically accrue to customers through Delta's Gas Cost Recovery mechanism.

Q. Does the Commission have authority to approve such a mechanism?

A. Yes. Kentucky Revised Statues Chapter 278.509 recognizes that such programs enhance regulatory efficiency, preserve economies for the Commission and its staff and save customer costs of repeated filings, stating that "...the Commission may allow recovery of costs for the investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility. No recovery shall be allowed unless the costs shall have been deemed by the Commission to be fair, just, and reasonable."

Q. Have similar mechanisms been approved for other distribution utilities in Kentucky?

A. Yes. The Commission approved a similar program for Columbia Gas of Kentucky, Inc. in Case No. 2009-00141 on September 18, 2009. Per Appendix B to an order of the Kentucky Public Service Commission in Case No. 2009-00354 dated April 1, 2010, Atmos Energy Corporation and the Attorney General of the Commonwealth of Kentucky agreed to implement the PRP as proposed by Atmos, pending approval of the Stipulation and Recommendation by the Commission.

Q. Provide a summary explanation of the PRP recovery mechanism.

A. Delta proposes a tracking mechanism to recover the costs of this system improvement on a timelier basis than provided by the traditional ratemaking process of repeated and more frequent rate cases. The cost recovery program is set forth in detail in the proposed tariffs in this filing.

Q. Does the tracking mechanism in Rider PRP mean that Delta will adjust its revenue requirement to recover its annual expenditures on pipe replacement in each year?

A. No. The annual cost of the program is not recovered in each year. The Company is allowed to earn a return on the investment only after the Commission has approved the actual PRP related expenditures, consistent with traditional ratemaking theory. We project that calendar 2010 investment under the PRP will be $1.5 million. Here is an example of the calculation provided in Rider PRP, assuming the calendar 2010 investment under the PRP equals our projection of $1.5 million. This amount would be reduced by the additional reserve for depreciation (assume this is $17,000 annually) and deferred income taxes related to the $1.5 million investment (assume this amount is $509,000). Subtracting $17,000 and $509,000 from $1,500,000 yields the sum $974,000 which we term the "net rate base for PRP purposes." The weighted cost of capital, calculated using the rate of return authorized in this case, adjusted for taxes, is applied to the net rate base to calculate the return on PRP related investment. In our example, that means $974,000 times 14.02% (Delta's proposed weighted cost of capital adjusted for taxes) or $137,000. The change in operating expenses associated with the PRP is the next step. For this example, assume the change in depreciation expense (computed at the depreciation rates approved in this case) associated with the PRP plant is $17,000. These changes are summed with the return component to determine the change in Delta's revenue requirement. In our example, $137,000 + $17,000 = $154,000. Thus, the Rider PRP annual adjustment would be $154,000.

Q. How would the rate adjustment be allocated to customer classes and rate components?

A. The rate adjustment would be spread proportionately to the monthly customer charge of Residential, Small Non-Residential, Large Non-Residential, Interruptible and On-System transportation customers based upon their relative base revenue share as proposed in this case. Continuing with the example of a PRP annual adjustment of $154,000, the monthly customer charge would increase as follows: Residential: $0.30, Small Non-Residential: $0.44, Large Non-Residential: $1.89 and Interruptible: $3.15. The increase for On-System Transportation customers would be the same as the increase for Small Non-Residential, Large Non-Residential and Interruptible customers, as applicable, set forth above.

Q. When does Delta propose to file its first PRP Rider filing?

A. Delta proposes to make its first filing on March 1, 2011. This filing would cover PRP investments made since the end of the test year in this case, that is, since December 31, 2009. Subsequent filings would be made on or about March 1 of each year, and would cover PRP investments made during the prior calendar year.

Q. How will main replacement expenditures be reflected in future base rate proceedings?

A. The ability to recover the depreciation and carrying costs related to the capital investment, less operating expense reductions, lowers Delta's need to file frequent rate applications. However, when a general rate case is filed, the program investment and reduced operating expense should be included in base rates and the Rider PRP reset to zero.

Q. What are the filing requirements associated with the proposed revenue adjustment for Rider PRP?

A. Delta proposes to submit its annual adjustment of Rider PRP on or about March 1 each year, to be effective with meter readings on and after its May billing cycle of the same year. The adjustment would be calculated to reflect actual activity for the prior calendar year and would be subject to Commission review.

UNCOLLECTIBLE GAS COST

Q. Please summarize your testimony on the issue of recovery of the gas cost component of bad debt through the GCR.

A. The Company's GCR is intended to provide recovery of 100% of the costs it incurs in procuring gas for its customers, no more, no less. The Company fails to receive 100% of the costs that it pays for natural gas when our customers do not pay their bills. Historically, the gas cost component of uncollectible accounts has been addressed in base rates but this recovery practice is inadequate in an era of volatile gas costs. Being authorized to recover the gas cost component of uncollectible accounts through its GCR mechanism would enhance the ability to recover all of the Company's gas costs.

Q. Why should the uncollectible portion of gas costs be treated differently than other expenses traditionally included in the Company's cost of service?

A. There is a clear distinction between the uncollectible portion of gas costs and other expenses included in a company's cost of service. The total bad debt expense is directly related to the total billings for residential, commercial and public authority accounts, which is largely driven by gas costs. Gas costs have exhibited much greater volatility in recent years due to national market issues beyond our local control. Providing for recovery of these gas costs through the GCR reduces the risk for customers and the Company that the level of expense set in base rates is too high or too low in future periods.

Q. Would allowing recovery of these costs through the GCR create a disincentive for the Company to aggressively pursue the recovery of bad debts?

A. No. Allowing recovery of the gas cost portion of bad debt does not create an incentive for the utility to deemphasize the collection of bad debts. The Company would continue to have $145,581 included in its base rates related to margin portion of uncollectible accounts. If collection efforts became lax and more write-offs were to occur, the Company would be exposed to incremental margin losses above those included in our base rates. The Company would retain every incentive to remain vigilant and maintain tight collection practices.

Q. How do you propose to modify the GCR tariff?

A. Delta proposes for the GCR tariff to allow the expected gas cost component (EGC) to include an estimate of Uncollectible Gas Costs. The quarterly estimate of Uncollectible Gas Costs will be a line item on Schedule II of the GCR filing. The actual Uncollectible Gas Costs booked will be reflected on Schedule IV of the GCR filing in the "Other Cost (Specify)" category of "Supply Cost Per Books".

Q. How do you propose that the actual Uncollectible Gas Cost amount be calculated?

A. Each month-end, when we determine the appropriate balance for our reserve for bad debts, we will calculate the percentage of gas costs booked to total revenue billed in the month and apply that percentage to the total provision needed to adjust the reserve for bad debts. The uncollectible base rate portion will be charged to uncollectible expense as it always has while the uncollectible gas cost portion will be charged to the unrecovered gas cost account on the balance sheet, and be relieved from that account as the EGC is billed.

Q. How will the Commission be able to review the Uncollectible Gas Cost Amounts?

A. We will present the Uncollectible Gas Cost amounts to the Commission for approval each quarter with the GCR filings.

Q. How will this method handle over- and under-recoveries?

A. Since the uncollectible gas cost will be treated the same as all gas cost, it will be subject to the same gas cost adjustment accounts which insures that the mechanism remains a dollar-tracker. Since the GCR is a dollar-tracker, every dollar of uncollectible gas cost will ultimately be recovered from our customers.

Q. In the event the Commission does not approve Delta's request for the Uncollectible Gas Cost, what do you propose?

A. In the event the PSC does not approve Delta's request for uncollectible gas cost, Delta should be permitted to recover uncollectible expense as has been the practice in Delta's past rate cases. This change would increase our adjustment to test year bad debt expense by $238,007.

Q. Has the Commission approved a similar proposal?

A. Yes. The Commission approved a similar proposal by Columbia Gas of Kentucky, Inc. in Case No. 2009-00141 on September 18, 2009. In Addition, Atmos Energy Corporation and the Attorney General of the Commonwealth of Kentucky agreed that Atmos' modification of the Gas Cost Adjustment Mechanism to allow recovery of uncollected gas costs through the mechanism is to be adopted and implemented as proposed per the Stipulation and Recommendation for Case No. 2009-0354 dated March 12, 2010.

Q. Does this conclude your testimony at this time?

A. Yes.

DELTA NATU GAS CO., INC.
Customer Count and Usage
Eight Years Ended December 2009

CUSTOMERS BILLED IN DECEMBER

	2009	2008	2007	2006	2005	2004	2003	2002
Residential	30,827	31,427	31,999	32,511	33,323	33,691	34,100	34,479
Small Non-Residential	4,203	4,329	4,402	4,449	4,513	4,545	4,629	4,667
Large Non-Residential	877	883	874	868	858	843	872	872
Interruptible	5	6	8	8	8	9	9	9
Delta Natural Retail	35,912	36,645	37,283	37,836	38,702	39,088	39,610	40,027

USAGE BILLED CALENDAR YEAR

	2009	2008	2007	2006	2005	2004	2003	2002
Residential	1,650,520	1,736,619	1,689,988	1,779,377	2,036,700	2,100,518	2,293,335	2,266,493
Small Non-Residential	515,838	542,126	521,733	544,497	604,106	630,092	697,273	667,590
Large Non-Residential	835,665	872,127	842,207	888,907	922,886	940,845	985,231	936,257
Interruptible	27,475	31,858	33,108	35,216	41,530	47,309	51,349	44,570
Delta Natural Retail	3,029,498	3,182,730	3,087,036	3,247,997	3,605,222	3,718,764	4,027,188	3,914,910

USAGE PER YEAREND CUSTOMERS

	2009	2008	2007	2006	2005	2004	2003	2002
Residential	53.5	55.3	52.8	54.7	61.1	62.3	67.3	65.7
Small Non-Residential	122.7	125.2	118.5	122.4	133.9	138.6	150.6	143.0
Large Non-Residential	952.9	987.7	963.6	1,024.1	1,075.6	1,116.1	1,129.9	1,073.7
Interruptible	5,495.0	5,309.7	4,138.5	4,402.0	5,191.3	5,256.6	5,705.4	4,952.2
Delta Natural Retail	84.4	86.9	82.8	85.8	93.2	95.1	101.7	97.8

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL	)	
GAS COMPANY, INC. FOR AN	)	**CASE NO. 2010-00116**
ADJUSTMENT OF RATES	)	

DIRECT TESTIMONY OF

MATTHEW D. WESOLOSKY

AFFIDAVIT

The affiant, Matthew D. Wesolosky, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2010-00116, in the Matter of: An Adjustment of Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional examination as may be appropriate at the hearing in Case No. 2010-00116 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

MATTHEW D. WESOLOSKY

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me by Matthew D. Wesolosky, this the 21st day of April, 2010.

My Commission Expires: 6/20/12

Emily P. Bennett
Notary Public, State at Large, Kentucky

Q. Please state your name and business address.

A. My name is Matthew D. Wesolosky. My business address is 3617 Lexington Road, Winchester, Kentucky, 40391.

Q. By whom and in what capacity are you employed?

A. I am employed by Delta Natural Gas Company, Inc. as its Manager – Accounting & IT.

Q. Please describe your professional and educational background.

A. I received a Bachelors of Science in Accounting from the University of Kentucky in 1999. I am a Certified Public Accountant in the State of Kentucky. From 1998 through 2001, I worked at Delta as the Accounting Systems Analyst/Coordinator. From 2001 through 2005 I worked in public accounting including two years at PricewaterhouseCoopers specializing in the utilities industry. From 2005 through 2007 I worked at Delta as the Manager – Internal Controls. Beginning in 2007 through present I have been employed by Delta as the Manager – Accounting & IT.

Q. Generally, what are your duties with respect to Delta?

A. I manage the daily operations of the Accounting and Information Technology Departments. My duties include maintaining Delta's accounting records to ensure the records properly reflect the financial position of the Company in accordance with generally accepted accounting principles and other regulatory requirements. This includes overseeing customer accounting and billing, payroll, property accounting, gas accounting and corporate accounting functions. I prepare the corporate income tax return and the workpapers to support the Company's tax positions, including the income tax provision and deferred income taxes. Delta retains Deloitte as their independent certified public accountants, with whom I work on a routine basis.

Q. Please describe your previous professional experience with Delta.

A. As the Manager – Internal Controls, I was primarily responsible for the monitoring and evaluation of Delta's internal controls. I reported to and acted on behalf of Delta's Audit Committee to assist in the Committee's oversight of Delta's corporate governance. I assisted in directing the Company's programs for compliance under Section 404 of the Sarbanes-Oxley Act of 2002 and assisted in coordination of the audit performed by our independent certified public accountants, Deloitte. As the Accounting Systems Analyst/Coordinator, my primary responsibility was to assist in the integration of the accounting and information technology departments.

Q. Please describe your public accounting experience related to the utilities industry.

A. I was a senior associate with PricewaterhouseCoopers from 2003-2005. During this time I primarily worked on the financial audits for E.ON U.S. and its subsidiaries (Louisville Gas and Electric Company, and Kentucky Utilities Company), Western Kentucky Energy Corp. and the audit of internal controls for Southwest Power Pool. I was in charge of planning and managing the audit fieldwork as well as focusing on industry specific issues dealing with regulatory accounting, energy trading and ISO transactions.

Q. Have you testified previously before the Commission?

A. Yes, I have been a witness on behalf of Delta in the following proceedings:

Case No. 2007-00089, *Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates,* and

Case No. 2008-00062, *Application of Delta Natural Gas Company, Inc, for Approval of A Customer Conservation/Efficiency Program and Demand Side Management Cost Recovery Mechanism.*

Q. Are you generally familiar with the business affairs of Delta?

A. Yes, I am.

Q. Please summarize the scope of your testimony.

A. I am sponsoring the following filing requirements:

• Proposed Tariff	Section 10(1)(a)7	Tab 7
• Proposed Tariff Changes	Section 10(1)(a)8	Tab 8
• Statement about Customer Notice	Section 10(1)(a)9	Tab 9
• Notice of Intent	Section 10(2)	Tab 10
• Customer Notice Information	Section 10(3)	Tab 11
• Sewer Utility Notices	Section 10(4)(a)	Tab 12
• Typewritten Notices by Mail	Section 10(4)(b)	Tab 13
• Other Customer Notices	Section 10(4)(c)	Tab 14
• Publisher's Affidavit	Section 10(4)(d)	Tab 15
• Verification – Mailed Notices	Section 10(4)(e)	Tab 16
• Sample Notices Posted	Section 10(4)(f)	Tab 17
• Comply w/ 807 KAR 5:051, Section 2	Section 10(4)(g)	Tab 18
• Hearing Notice Published	Section 10(5)	Tab 19
• New Rates Effect – Overall Revenues	Section 10(6)(d)	Tab 23
• Average Customer Class Bill Impact	Section 10(6)(e)	Tab 24
• Local Telephone Exchange Companies	Section 10(6)(f)	Tab 25
• Current Chart of Accounts	Section 10(6)(j)	Tab 29
• Annual Auditor's Opinion(s)	Section 10(6)(k)	Tab 30
• Computer Software, Hardware, etc.	Section 10(6)(o)	Tab 34

- Monthly Managerial Reports — Section 10(6)(r) — Tab 37
- Affiliate, et al., Allocations/Charges — Section 10(6)(t) — Tab 39

Q. Do you adopt these filing requirements and make them part of your testimony?

A. Yes.

Q. Please explain Tab 24, the effect of the proposed rates on the average bill for each customer class.

A. Tab 24 contains a comparison of average bills at present rates with average bills at proposed rates. Average bills are presented separately for the different customer classes. The percentage of increase in annual revenues to Delta will approximate 11.54%. The effect upon consumer bills will vary depending upon usage.

Q. Is Delta proposing new tariffs or changes to existing tariffs?

A. Yes. Delta is proposing a new tariff related to our Pipe Replacement Program. A copy of the new tariff is included in Tab 7 and further discussion of the tariff can be found in the Direct Testimony of John B. Brown. Delta is proposing a change to its Gas Cost Recovery Clause to include recovery of gas costs that have been written off as bad debts, which is further described in the Direct Testimony of Mr. Brown. Additionally, there have been some minor wording changes in the Gas Cost Recovery Clause to better describe the calculation of the expected gas cost component of the Gas Cost Recovery tariff.

Q. Please explain why the proposed tariff changes included in Tab 8 shows a decrease in the Conservation and Efficiency Program Cost Recovery Component from \$0.0085 per Ccf, as approved in filing no. TFS2009-00923 to \$0.0077 per Ccf.

A. We have adjusted the Conservation/Efficiency Program Lost Sales (CEPLS) component of the Conservation/Efficiency Program Cost Recovery Component from $0.0085 per Ccf to $0.000 per Ccf. Pursuant to page 15 of the Conservation/Efficiency Program, filed as Exhibit I in Case No. 2008-00062, "lost sales are based on the cumulative lost sales since the program inception and will reset when a company completes a general rate case." Thus, we are resetting the CEPLS component.

Q. Please explain Tab 30, Section 10(6)(k).

A. Tab 30 Section 10(6)(k) contains the independent auditor's annual opinion reports which is part of the Company's Annual Report to Shareholders for the year ended June 30, 2009. The Company's independent accounting firm is Deloitte. Two opinions are issued in connection with the Annual Report to Shareholders. The first report is an unqualified opinion on the financial statements taken as a whole. The second opinion is an unqualified opinion stating that Delta's assessment of internal controls is fairly stated. Based on the opinions issued by Deloitte, there were no material weaknesses or significant deficiencies in internal control, and therefore no correspondence regarding such items.

Q. Does this conclude your testimony at this time?

A. Yes it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF RATES	**)))**	**CASE NO. 2010-00116**

DIRECT TESTIMONY OF

MARTIN J. BLAKE

AFFIDAVIT

The affiant, Martin J. Blake, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2010-00116 in the Matter of: Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional examination as may be appropriate at the hearing in Case No. 2010-00116 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

Martin J. Blake
MARTIN J. BLAKE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me by Martin J. Blake, this the 19th day of April, 2010.

My Commission Expires: 9/13/11

Notary Public, State at Large, Kentucky

BRYAN S. POTTER, JR.
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
MY COMMISSION EXPIRES SEPTEMBER 13, 2011

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Martin J. Blake. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q: BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A: I am a Member and Principal of The Prime Group, LLC. The Prime Group provides consulting services in the areas of cost of service, rate design, regulatory support, training, and strategic planning for energy industry clients.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Delta Natural Gas Company, Inc. ("Delta") engaged The Prime Group to conduct an analysis of and to provide a recommendation regarding the appropriate cost of common equity for use in determining Delta's weighted cost of capital in this proceeding. My testimony contains the results of this analysis and identifies the fair rate of return on equity that Delta should be given the opportunity to earn during the period when the new rates will be in effect. My analysis utilizes appropriate financial valuation techniques and incorporates the factors that affect the return on equity that shareholders expect when investing in Delta and in other companies of corresponding risk.

Professional Qualifications & Experience

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A: I received my Ph.D. in Agricultural Economics in 1976 from the University of Missouri, Columbia. My doctoral work centered on the areas of marketing and econometrics. I also hold a Master of Arts in Economics from the University of Missouri, Columbia, which I received in 1972. In addition, I received a Bachelor of Arts degree in Economics from Illinois Benedictine College in 1970.

Q: HAVE YOU FILED TESTIMONY REGARDING THE APPROPRIATE RETURN ON EQUITY IN OTHER PROCEEDINGS?

A: Yes. I have filed testimony regarding the appropriate return on equity in Federal Energy Regulatory Commission Docket No. ER01-1938 in support of Southern Indiana Gas and Electric Company's request for a revision in transmission and ancillary service rates including cost of capital testimony. I have filed testimony regarding the appropriate return on equity in Federal Energy Regulatory Commission Docket No. ER02-708 in support of Central Illinois Power Company's request for a revision in transmission and ancillary service rates including cost of capital testimony. I have filed testimony regarding the appropriate return on equity in Docket Nos. 99-046, 2004-00067 and 2007-00089 before the Kentucky Public Service Commission regarding the return on equity in support of Delta Natural Gas Company's requests for adjustments in rates.

Q: PLEASE BRIEFLY SUMMARIZE YOUR AREAS OF PROFESSIONAL EXPERIENCE PRIOR TO JOINING THE PRIME GROUP.

A: I have professional experience as an economist and professor of economics, as a utility regulator, and as a utility manager and executive.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS AN ECONOMIST.

A: From January 1977 to December 1986, I was employed first as an Assistant Professor, then as an Associate Professor, and finally as a Professor of Agricultural Economics at New Mexico State University in Las Cruces, New Mexico ("NMSU"). I was the head of the undergraduate program and taught economics, agricultural economics and econometrics. While at NMSU, I also worked as a consultant for various clients, providing price forecasting, load forecasting, and marketing services. Since 1992, I have taught mathematical economics and econometrics as an Adjunct Professor in the Economics Department at the University of Louisville. Prior to my joining the faculty at NMSU, I served in the U. S. Army as an instructor of economics, statistics, and accounting at the U. S. Army Institute of Administration at Fort Benjamin Harrison, Indianapolis, Indiana.

I also have a wealth of experience with the application of economics to utility public policy issues. In addition to my experience as a utility regulator and executive, which I describe below, I have taught ratemaking for utilities at the NARUC Annual Regulatory Studies Program at Michigan State University since 1993. From May 1983 to August 1983, while on a sabbatical leave from NMSU, I served as a Policy Analyst for the Assistant Secretary for Land and Water at the U. S. Department of Interior.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A UTILITY REGULATOR.

A: From January 1987 to November 1990, I served as a Commissioner and as the Chairman of the New Mexico Public Service Commission. As a Commissioner, my duties included making policy and adjudicatory decisions regarding rates, terms of service, financing, certificates of public convenience and necessity, and complaints for electric, gas, water, and sewer utilities. I interpreted legislation, reviewed prior Commission cases to determine the precedents that they provided, drafted rules and regulations, wrote orders, conducted hearings, ruled on motions, and served as an arbitrator in alternative dispute resolution proceedings. I performed adjudicatory and regulatory functions for the four years that I served on the Commission.

As Chairman, I supervised a staff of thirty-two professionals and sixteen support staff. During my tenure on the New Mexico Commission, I also served as Chairman of the Western Conference of Public Service Commissioners Electric Committee and as Chairman of the Committee on Regional Electric Power Cooperation, a group composed of state public service commissioners and representatives from the state energy offices of the thirteen western states.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A UTILITY MANAGER.

A: From December, 1990 to June 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). Initially, I served as LG&E's Director of Regulatory Planning. In this position, I was responsible for coordinating all of LG&E's state and federal regulatory efforts, and prepared and presented testimony to regulators. My areas of responsibility were expanded in April 1994 to include marketing and strategic planning. As the Director, Marketing, Planning and Regulatory Affairs, I was responsible for coordinating LG&E's retail gas and electric marketing, strategic planning, and state and federal regulatory efforts. I continued to be employed in that capacity at LG&E until June 1996, when I joined The Prime Group as one of its Principals.

Q: PLEASE DESCRIBE THE INDUSTRY GROUPS IN WHICH YOU HAVE PARTICIPATED.

A: I have served on several regional transmission coordination groups such as the Interregional Transmission Coordination Forum, and the General Agreement on Parallel Paths, as well as the following committees of the Edison Electric Institute ("EEI"): Economics and Public Policy Executive Advisory Committee, Strategic Planning

Executive Advisory Committee, Transmission Task Force, and Power Supply Policy Technical Task Force. Currently, I am a member of the Midwest ISO Transmission Owners Committee and the Transmission Owners Tariff Working Group representing Southern Illinois Power Cooperative and Hoosier Energy. I served a three year term as the Chairman of the Transmission Owners Tariff Working Group and am currently the Vice-Chair of the Midwest ISO Finance Subcommittee.

Q: HAVE YOU TAUGHT ANY COURSES OR SEMINARS IN THE AREA OF UTILITY REGULATION?

A: Yes. I have taught the following courses at the NARUC Annual Regulatory Studies Program at Michigan State University: 1) retail ratemaking, 2) wholesale pricing, 3) rate of return regulation, 4) competitive market fundamentals, 5) electric industry overview, 6) the economics of power production and delivery, 7) electric system technologies, and 8) the institutions and organizations of the new electric utility industry. Each year, I also teach and conduct numerous workshops and programs and deliver invited presentations to utility managers and regulators on a variety of subjects.

Q. IN WHICH CASES HAVE YOU PREVIOUSLY TESTIFIED?

A. A list of the cases in which I have previously testified is included in Exhibit MJB-1.

Return on Equity

Q. PLEASE DESCRIBE DELTA'S BUSINESS OPERATIONS.

A. Delta purchases, produces and stores natural gas for distribution to retail customers, and also provides transportation service to industrial customers and interconnected pipelines through facilities located in 23 counties in central and southeastern Kentucky. The Company had 35,912 retail customers at the end of 2009. Its service territory is more rural than those of most publicly traded, investor owned natural gas distribution companies and consists mainly of light industry, farming and coal mining operations. Approximately 86% of Delta's customers are residential.

Exhibit MJB-2 shows a ranking of Delta's total capitalization compared to other publicly traded, investor owned natural gas distribution utilities. The data in Exhibit MJB-2 was taken from a report titled Natural Gas Industry Summary Quarterly Financial & Common Stock Information issued by Edward Jones Co. dated December 31, 2009. This report classifies companies that provide natural gas into three categories: 1) diversified companies, 2) combination gas and electric companies and 3) natural gas distribution companies. Delta is classified as a natural gas distribution company. Among the publicly traded, investor owned natural gas distribution utilities included in this report Delta was the third lowest with respect to total capitalization.

Exhibit MJB-3 contains a ranking of the publicly traded investor owned natural gas distribution companies based on the percentage of equity in the companies' capital structures. These equity percentages are calculated using long term debt and equity and do not include short term debt in the calculation of the equity percentage for a company. Thus, the percent equity in the Edward Jones report is different than the percentage of equity in the capital structure for Delta in this proceeding. However, because it uses the same calculation for all companies in the panel, the Edward Jones report does provide a good basis for comparing the companies in the panel with regard to the equity component of their capitalizations. Exhibit MJB-3 shows that the two natural gas distribution utilities with a lower total capitalization than Delta had percentages of equity of 61.5% and 57.6%, which are higher than Delta's 45.7% equity percentage. Furthermore, the only natural gas distribution utility with a percentage of equity lower than Delta had a total capitalization that was 32 times larger than Delta's total capitalization. Thus, Delta can be characterized as a small, publicly traded, investor owned, natural gas distribution utility with an essentially rural service territory and with a relatively highly leveraged capital structure relative to other natural gas distribution utilities shown in Exhibit MJB-3.

Q. HOW DOES DELTA'S EARNED RETURN ON EQUITY FOR 2009 COMPARE WITH OTHER NATURAL GAS DISTRIBUTION COMPANIES?

A. Exhibit MJB-4 contains a ranking of the publicly traded investor owned natural gas distribution companies based on return on equity. This exhibit shows that the only two companies with a total capitalization lower than Delta had higher earned returns on equity of 10.9% and 10.4% compared to Delta's earned return on equity of 7.5%.

Q. IS THERE A PUBLIC BENEFIT TO PROVIDING NATURAL GAS SERVICE TO RURAL AREAS?

A. Yes. If natural gas service is available in an area, customers have a choice whether to use natural gas or electricity for particular applications. Customers' ability to switch between natural gas and electricity helps to keep downward pressure on the prices of both products. Furthermore, the availability of natural gas service can help in attracting industrial loads to an area and thus assist in economic development efforts. However, if natural gas service is to be provided to rural areas, the companies providing such service must have the opportunity to earn adequate returns or they will no longer be able or willing to provide such service. Additionally, in order to expand Delta's service into additional rural areas, either through main extensions or through acquisition of other natural gas companies, Delta needs a sufficiently high allowed return on equity in this proceeding to increase the percentage of equity in its capital structure to a level more appropriate for a company of its size, decrease its payout ratio which is well above the industry average as shown in Exhibit MJB-5, and increase its interest coverage which is below the industry average as shown in Exhibit MJB-6. I discuss each of these important objectives later in my testimony. None of this can be done with a return on equity that is inadequate.

Q. PLEASE COMPARE DELTA'S PERFORMANCE FOR ITS SHAREHOLDERS TO OTHER NATURAL GAS DISTIBUTION COMPANIES.

A. Delta's earnings per share growth was negative 44.8% in 2009 which was the second lowest in the panel of natural gas distribution companies, as shown in Exhibit MJB-7, and was well below the mean earnings per share growth of negative 10.1%. Delta's 5-year total return on investment was the lowest of all of the natural gas distribution utilities at 32.5% compared to the mean of 55.6%, as shown in Exhibit MJB-8. Similarly, Delta's 5-year dividend growth was the second lowest of all of the natural gas distribution utilities at 2.0% compared to the mean of 4.7%, as shown in Exhibit MJB-9. The financial performance shown in Exhibits MJB-3, MJB-4, MJB-5, MJB-6, MJB-7, MJB-8 and MJB-9 may make it difficult for Delta to continue to attract capital in the future. It is essential that the Commission allow Delta a sufficiently high rate of return on equity in this proceeding to turn this performance around.

Q. HOW SHOULD THE RATE OF RETURN BE DETERMINED UNDER PUBLIC UTILITY REGULATION?

A. The purpose of public utility regulation with respect to rate of return is to permit a utility the opportunity to earn its cost of capital while avoiding monopoly profits. Long-run earnings above the cost of capital would imply monopoly profits, while long-run earnings below the cost of capital would impair a utility's ability to attract capital on reasonable terms. A rate of return based on a utility's cost of capital is consistent with the guidelines established by the U.S. Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944). These cases require that a utility be allowed to earn a rate of return that: 1) is comparable to alternative investment opportunities of corresponding risk, 2) will permit capital attraction on reasonable terms, and 3) will maintain a utility's financial integrity.

In the *Hope* case, the U.S. Supreme Court stated that:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard <u>the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks</u>. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. (emphasis added) [*Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).]

It is important to note that the U.S. Supreme Court did not limit the return on equity to being commensurate with that of other utilities. It stated that the return on equity should be commensurate with other companies having corresponding risk. Later in my testimony I will utilize a panel of companies with similar risk as Delta as measured by the beta value reported in <u>Value Line</u>. This applies the Supreme Court's standard of returns to enterprises of corresponding risk without limiting the panel of companies to natural gas distribution utilities or to the utility industry as a whole. This is an important comparison because the return on equity for these companies is determined in the market and is not set through the regulatory process.

Q. HOW DO YOU INTERPRET THE REQUIREMENT THAT A UTILITY HAVE

AN OPPORTUNITY TO EARN A FAIR RATE OF RETURN?

A. An opportunity to earn a fair rate of return implies that a utility has a reasonable assurance that it will be allowed to earn a rate of return that is sufficient to attract capital, that will maintain its financial integrity and that is comparable to the return earned by alternative investments of comparable risk. While there are numerous factors that may result in an actual rate of return that is higher or lower than the allowed rate of return in any given year, a utility that consistently earns less than the allowed rate of return or which has averaged significantly less than the allowed rate of return for a long period of time cannot be said to have a reasonable assurance of earning the allowed rate of return. Thus, an assurance of earning a fair and reasonable rate of return could be viewed statistically as the arithmetic average of a series of returns over a period of time equaling the allowed rate of return.

Q. WOULD YOU REGARD DELTA'S CURRENT RATES AS PROVIDING AN OPPORTUNITY TO EARN AN ADEQUATE RETURN FOR PROVIDING NATURAL GAS SERVICE TO ITS CUSTOMERS?

A. No, I would not. Exhibit MJB-10 shows the actual earned return on equity for Delta as reported by the Value Line Survey –Small and Mid-Cap Edition compared to the allowed rates of return granted by the Commission in various Delta rate cases for the period 1995-2009. The earned returns for Delta reported in Value Line are for the consolidated entity, i.e. Delta's combined regulated and unregulated activities. Exhibit MJB-11 shows both the earned returns on equity for the consolidated company and for the regulated entity alone for the period 2000-2009.

In December, 1997, the Commission issued an Order in Case No. 97-066 which set new rates for Delta which became effective in January, 1998. In that case, the Commission allowed a return on common equity of 11.6%. In December, 1999, the Commission issued an Order in Case No. 99-046 which set new rates for Delta which became effective in January, 2000. In that case, the Commission also allowed a return on common equity of

11.6%. In November, 2004, the Commission issued an Order in Case No. 2004-00067 which set new rates for Delta which became effective on October 7, 2004. In that case, the Commission allowed a return on common equity of 10.5%. In October, 2007, the Commission issued an Order in Case No. 2007-00089 which set new rates for Delta. In that case, the Commission allowed a return on common equity of 10.5%. However, Exhibit MJB-10 shows that for the fifteen year period from 1995 to 2009, only once has the consolidated company earned an actual return on shareholders' equity that was as high as the return on equity allowed by the Commission in Delta's most recent rate case. Exhibit MJB-10 shows that Delta has averaged a 9.33% return on shareholder equity for the consolidated company for this fifteen year period compared to an average Commission approved ROE of 11.05%. Exhibit MJB-11 shows that the regulated entity has never earned its allowed rate of return for the period 2000-2009. When Delta as a regulated entity has never earned a return on shareholder equity that was equal to or greater than the return on equity allowed by the Commission for ten successive years, it cannot be said to have a reasonable assurance of earning the allowed rate of return. Delta's actual annual earned returns on equity for the regulated entity should have the same mean as the allowed rate of return with actual annual earned returns both above and below the allowed rate of return. This has not been the case for the last ten years, and it indicates a problem that the Commission could remedy by allowing Delta a higher allowed ROE in this proceeding than it has approved in the past in order to allow Delta to build equity. A percentage of equity that is well below natural gas distribution companies of similar size likely contributes significantly to the under-earning problem that Delta has experienced historically, as will be explained more fully below.

Q. SHOULD THE COMMISSION CONSIDER THE RETURN ON EQUITY FOR THE CONSOLIDATED COMPANY WHEN DETERMINING A FAIR RETURN ON EQUITY FOR DELTA IN THIS PROCEEDING?

A. No. Because the Commission would not allow Delta to recover from its customers any losses from its unregulated activities, it is also not appropriate for the Commission to consider any profits that Delta might earn from its unregulated activities when determining a fair return on equity for Delta. Thus, the returns on equity reported for the regulated entity in Exhibit MJB-11 are the appropriate returns for the Commission to consider in determining Delta's allowed return on equity in this proceeding, and a review of Exhibit MJB-11 shows that these returns on equity for the regulated entity have been very low, never exceeding 7.2% for the period 2000-2009.

Q. WHAT FACTORS DO YOU BELIEVE HAVE CAUSED DELTA TO UNDER EARN COMPARED TO ITS ALLOWED RATE OF RETURN ON EQUITY?

A. I believe that there are several factors: 1) Delta's equity as a percentage of total capitalization is lower than other natural gas distribution companies of similar size, 2) Delta's predominantly rural service territory, 3) customer conservation in response to higher natural gas prices, and 4) efficiency gains of natural gas appliances. Customer conservation in response to higher prices and efficiency gains of natural gas appliances result in under recovery of Delta's fixed costs and margin when a significant portion of fixed cost and margin are collected through a volumetric charge rather than through a fixed charge per customer per month. With a significant portion of Delta's fixed costs and margins currently collected using a volumetric charge, both customer conservation and appliance efficiency gains have lead to under recovery as these factors have reduced the per customer usage of natural gas. This problem could be mitigated by the Commission approving the full cost based customer charge that Delta is requesting in this proceeding.

Q. PLEASE DESCRIBE DELTA'S EQUITY AS A PERCENTAGE OF TOTAL CAPITALIZATION COMPARED TO OTHER NATURAL GAS DISTRIBUTION COMPANIES.

A. As described above, Exhibits MJB-2 and MJB-3 provide data for natural gas distribution companies ranked by total capitalization and percentage equity, respectively, taken from <u>Natural Gas Industry Summary Monthly Financial & Common Stock Information</u>

published by Edward Jones. The mean percentage of equity is calculated as 50.9% for the panel of eleven natural gas distribution utilities with a median of 49.9%. These percentages are calculated using long term debt and equity and do not include short term debt in the calculation of the equity percentage for a company. The capital structure that includes both short and long term debt and that is used as the capital structure in this proceeding is shown in Exhibit MJB-12 and reflects 44.5% equity and 54.5% debt. Thus, the percent equity in the Edward Jones report is different than the percentage of equity in the capital structure for Delta in this proceeding. However, because it uses the same calculation for all companies in the panel, it does provide a good basis for comparing the companies in the panel with regard to the equity component of their capitalizations. As noted above, the percentage of equity for the two companies smaller than Delta are 61.5% and 57.6%. The percentage of equity for the company that is the next largest is 56.2%. Delta's reported percentage of equity of 45.7% is 5.2% below the mean and 4.2% below the median for this panel, making Delta more heavily leveraged than other natural gas distribution utilities of similar size.

Q. DOES A LOWER PERCENTAGE OF EQUITY RELATIVE TO TOTAL CAPITALIZATION MAKE DELTA A RISKIER INVESTMENT?

A. Yes. The more debt that a firm has as a part of its total capitalization, the greater are the fixed interest payments that the firm will have to make to bond holders out of any given revenue stream that it generates. A company is required to make payments to the bond holders in specified amounts at specified times, while it is under no such obligation to its common equity holders. Thus, the more equity the firm has, the greater is its ability to deal with revenue fluctuations. However, this flexibility comes at a cost, as equity is more expensive than debt because of the greater risk that shareholders bear. As a company's business environment becomes riskier and its business risk becomes greater, the company should increase its equity and lower its debt ratio. By reducing its debt ratio, its fixed obligations to bond holders would be reduced and the company would be better able to manage the financial fluctuations that result from a riskier business environment. Furthermore, a utility's equity ratio must be high enough to allow additional debt capital to be issued without an adverse effect on its credit rating. This would be consistent with the criteria established in the *Bluefield* and Hope cases that the rate of return be sufficient to permit capital attraction on reasonable terms. If the capital structure does not permit some margin for additional debt financing at all times, a utility is subject to the potential adverse impact of unanticipated tight credit conditions, thus making it a riskier investment. Delta is below both the average percentage equity for the panel of eleven natural gas distribution companies and the average percentage equity for natural gas distribution companies of similar size as Delta. Getting Delta's percentage of equity closer to the average for natural gas distribution companies of a similar size will only occur if the Commission allows a high enough rate of return to accommodate this long term improvement in Delta's equity ratio.

Q. HOW WOULD DELTA'S LOW EQUITY RATIO AFFECT THE RETURN ON EQUITY THAT IT EARNS?

A. Because Delta is about 54.5% debt financed based on the capital structure in this proceeding, its fixed obligations to bondholders exacerbate the impact on the return on equity resulting from any revenue reductions that Delta might experience. This is an important factor that contributes to the fact that Delta has earned its allowed rate of return only once in the past fifteen years.

Q. COULD YOU GIVE AN EXAMPLE OF HOW LEVERAGE MIGHT AFFECT THE ACTUAL RETURN ON EQUITY EARNED BY DELTA?

A. Yes. Exhibit MJB-13 provides several examples of how a change in the percentage of equity in Delta's overall capitalization would affect the actual return on equity earned by Delta. All three examples in Exhibit MJB-13 have the same total capitalization, but have different equity ratios. The first example in Exhibit MJB-13, uses the same percentage of equity and debt as Delta's capital structure in this proceeding and assumes a return on equity of 10.5% and an interest rate of 6.74% on the debt, which is what the Commission approved in Case No. 2007-00089. The dollar value of the return elements for equity and debt are calculated by multiplying the dollar value of the equity and debt capitalization by their respective rates of return and interest. In Example 1, the dollar value of the return element for equity would be $5,931,695 and the dollar value of the return element for debt would be $4,749,997. Next assume that Delta experiences a decrease in earnings of $960,000. Delta would still have to pay $4,749,997 to debt holders and now would have only $4,971,695 to provide to shareholders. Dividing $4,971,695 by the $56,492,338 of equity capitalization would result in an actual return on equity of 8.80%, which is what Value Line reported as an earned return on equity for Delta for 2009.

Example 2 uses a capital structure that reflects the industry average as calculated in Exhibit MJB-2 and uses the same rates of return and interest as in Example 1. Thus, the only factor that is changing is the equity and debt ratios. Again a decrease in earnings of $960,000 is assumed. Delta would still have to pay $4,201,772 to debt holders and now would have only $5,825,755 to provide to shareholders. Dividing $5,825,755 by the $64,626,236 of equity capitalization would result in an actual return on equity of 9.01%. In both Examples 1 and 2, the $960,000 decrease in earnings is a result of operations and is not influenced by the capital structure used to finance the company. However, this same $960,000 decrease in earnings has a very different impact on the actual return on equity depending on the debt leverage of the company.

A comparison of Examples 1 and 2 also illustrates another important point. In Example 2, the return element included in the revenue requirement would be $10,987,527, while in Example 1 the return element included in the revenue requirement would be $10,681,692, which is $305,835 lower. Thus, with a lower percentage equity ratio than the industry as a whole, Delta's customers pay lower rates while Delta experiences a significant adverse effect on its ability to earn its allowed rate of return if it experiences any earnings shortfalls. This is simply not an equitable result.

Example 3 simply repeats the above example for a capital structure similar to the highest equity percentage in the panel of eleven natural gas distribution companies, namely 61.5% equity and 38.5% debt for RGC Resources. In Example 3, the $960,000 decrease in earnings would result in an actual return on equity of 9.27%. This is 47 basis points higher than the earned return using Delta's capital structure for the same revenue decrease and same total capitalization. This basis point spread widens as the revenue decrease is larger. For a $2,000,000 revenue decrease there would be a difference of 98 basis points between the earned ROEs for Delta's and RGC Resources' capital structures, other assumptions remaining constant. There would be a 147 basis point difference for a $3,000,000 revenue decrease.

These three examples illustrate that Delta's equity ratio, which is below both the industry average and the average for natural gas distribution companies of similar size, has a significant adverse effect on its ability to earn its allowed rate of return. Any given earnings shortfall for Delta will result in a lower earned return on equity than for the average natural gas distribution company. These examples help in understanding why Delta has earned its allowed rate of return only once in the past fifteen years. This significant adverse impact on Delta's ability to earn its allowed rate of return must be considered by the Commission in setting an appropriate rate of return for Delta. The Commission should allow Delta a sufficiently high rate of return to increase its equity percentage and mitigate this problem.

Q. HOW WOULD DELTA'S PREDOMINANTLY RURAL SERVICE TERRITORY AFFECT THE RETURN ON EQUITY THAT IT EARNS?

A. Delta serves an area in eastern Kentucky that is predominantly rural with low population density. This low population density results in higher fixed cost per customer for serving rural areas compared to the fixed cost per customer incurred in an urban area. This higher fixed cost per customer results from both a higher cost of installing the pipe needed to serve a customer and the higher cost of maintaining the lines. Furthermore, these rural customers tend to have a lower annual usage and a larger proportion of temperature sensitive load than urban customers. This relatively high fixed cost to serve small highly temperature sensitive loads translates to a higher fixed cost burden for Delta and a more variable revenue stream. The higher fixed costs resulting from operations compounds the problem of high fixed obligations to bond holders resulting from a low equity ratio, and exacerbates the impact on the return on equity resulting from any revenue reductions that Delta might experience, as demonstrated above. Thus, the low population density in rural areas that results in a higher fixed cost burden for Delta with more variability in the return stream due to the large amount of temperature sensitive load for these rural customers would justify a higher allowed rate of return for Delta. It would be very difficult, if not impossible, to quantify the separate impact on return on equity resulting from the rural character of Delta's service territory. However, this factor combined with a lower than average equity ratio for Delta, would justify a higher than average rate of return on equity for Delta.

Q. HOW WOULD YOU ASSESS THE COMPETITION WHICH DELTA FACES FROM OTHER ENERGY SUPPLIERS?

A. Delta provides natural gas service in a service territory that substantially overlaps the electric service territory of Kentucky Utilities Company, which has some of the lowest electric rates in the nation. This direct competition with a low cost electric utility increases Delta's business risk.

Q. DOES DELTA'S SIZE AFFECT THE RETURN ON EQUITY THAT IT SHOULD BE ALLOWED IN THIS PROCEEDING?

A. Yes. Delta is a small company with a capitalization that would fall in the second subdivision of the smallest micro-cap stock decile range (category 10x) as defined in the <u>Ibbotson SBBI 2010 Valuation Yearbook</u> published by Morningstar, which includes companies with market capitalizations at or below $169,497,000 and above $123,516,000. This source states that:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire spectrum but is most evident among smaller companies, which have higher returns on average than larger ones. (Ibbotson SBBI 2010 Valuation Yearbook, Morningstar Inc., p. 85)

This source goes on to state that:

> Table 7-5 illustrates that the smaller deciles have had returns that are not fully explained by their higher betas. This return in excess of that predicted by CAPM increases as one moves from the largest companies in decile 1 to the smallest in decile 10. The excess return is especially pronounced for micro-cap stocks (deciles 9 - 10). This size phenomenon has prompted a revision of CAPM, which includes a size premium. (Ibbotson SBBI 2010 Valuation Yearbook, Morningstar Inc., p. 90)

Valuation Yearbook went on to report that this size premium relationship continued to hold as the smallest decile of companies was divided into four subcategories (10w, 10x, 10y and 10z), with the return increasing as size of the company decreased. Valuation Yearbook reports that the estimated return above the riskless rate for companies in category 10x, which would include Delta, averaged 9.69 % over the period 1926-2009 and that the estimated return in excess of CAPM was 4.91% for companies in category 10x. This means that a higher rate of return on equity would be appropriate for small companies such as Delta. The Commission should, thus, resist the temptation to conclude that Delta should have the same return on equity as the other four major natural gas distribution companies in Kentucky. It is simply not consistent with these research results to allow all natural gas distribution companies in Kentucky essentially the same return on equity when the other four major investor-owned natural gas companies in Kentucky are part of corporations that are over 30 times larger than Delta.

Q. DOES THE INCREASED VOLATILITY IN NATURAL GAS PRICES AFFECT THE RETURN ON EQUITY THAT DELTA SHOULD BE ALLOWED TO EARN?

A. Yes. Delta has a Gas Cost Recovery ("GCR") mechanism that is calculated quarterly. Any under or over recoveries during a quarter are recovered over the next twelve months. Delta is not allowed to earn a return on any money that it has devoted to funding such under-recoveries. Increased price volatility has resulted in significant under-recoveries and deferred gas costs that Delta has had to finance with no interest. The following table shows the amount of under-recovery and deferred gas costs that Delta was carrying at the end of each of the last five calendar years.

December 2005	$7,363,944
December 2006	$1,117,889
December 2007	$3,377,138
December 2008	$6,032,930
December 2009	$1,573,758

Delta has had to finance these under-recoveries with a mix of internal financing and short term borrowing. The interest that Delta incurs in financing any under-recoveries is an expense that is not recovered by Delta through the GCR. This has helped to generate earnings shortfalls that are exacerbated by Delta's low equity ratio as demonstrated above. Any additional hedging that Delta might do to reduce the price volatility of the natural gas commodity comes at a cost; namely increasing the long-run average cost of natural gas paid by customers as the cost of the hedging program is added to natural gas commodity costs. Customers benefit from the current arrangement by not having to pay these costs and further benefit by not having to pay Delta interest on the under-recovery amounts. A higher return on equity would provide a larger pool of internal resources to finance such under-recoveries and would help to mitigate Delta's reliance on short term borrowing. Natural gas commodity price volatility is a significant risk factor when Delta has to finance these costs with no interest recovery allowed. The Commission should allow a return on equity that would help to provide Delta with the internal capital necessary to fund such under-recoveries and mitigate the necessity of using short term debt for these purposes.

Q. HAVE YOU CONDUCTED OBJECTIVE ANALYSES OF RETURNS ON EQUITY THAT WOULD BE APPROPRIATE FOR DELTA?

A. Yes. I have performed two discounted cash flow analyses, a capital asset pricing model analysis, a risk premium analysis and an analysis of companies with corresponding risk..

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") METHOD FOR ESTIMATING THE APPROPRIATE RETURN ON EQUITY.

A. The DCF method for estimating an appropriate return on equity is based on the following equation, which defines the long run expected return (the appropriate return on equity) as the discount rate that equates the current stock price with the stream of expected future dividends:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \frac{D_4}{(1+k)^4} + \cdots$$

where,

P = the current price of the stock,

D_i = the dividend in year i, and

k = the investors' discount rate or expected rate of return.

If the growth is a constant rate, g, this equation can be expressed as the sum of an infinite geometric series:

$$k = \frac{D_1}{P} + g$$

While the DCF method is usually calculated using this formula, it can also be described in words. The terms in the DCF formula represent investors' assessment of expected future cash flows they will receive in relation to the price that they pay for a share of stock. The DCF formula says that the return that any investor expects from the purchase of a stock consists of two components. The first is an initial cash flow in the form of a dividend. The second is the cash flow resulting from dividend growth in the future. Although investors know that negative growth and losses can occur, rational investors expect long term positive dividend growth. Otherwise they would hold cash rather than invest with the expectation of a loss. The sum of the rates of these two flows, initial and future, equals the return that investors require from their investment in the stock at the current price. Investors adjust the price they are willing to pay for the stock until the sum of the dividend yield and the annual rate of expected future growth in dividends equals the rate of return they expect from other investments of comparable risk. The DCF calculation determines what shareholders require from a company in terms of present and future dividends relative to the current market price of the company's stock. If the DCF model indicated a return on equity of 8% and the current stock price used to calculate this return on equity was $25, this tells us that shareholders are expecting an 8% return on equity in return for their $25 investment in the stock, i.e. an 8% return on the market equity, not on the book equity or on rate base which have little or no relation to the market equity.

Q. DOESN'T THE GROWTH RATE THAT IS ULTIMATELY SELECTED BY THE COMMISSION IN CALCULATING RETURN ON EQUITY USING THE DCF METHODOLOGY BECOME A SELF-FULFILLING PROPHECY?

A. Yes. If the Commission selects a high growth rate resulting in a higher return on equity, there will be sufficient earnings to grow dividends and increase the equity component of Delta's capital structure. If the Commission selects a low growth rate, the lower level of earnings will only allow dividends to increase slightly, if at all. Thus, looking at historic dividend growth rates is not a good indicator of investor expectations with regard to dividends. It simply reflects the return on equity that the Commission has allowed Delta in the past. And as noted above, Delta's actual earned returns for the consolidated entity have been lower than the allowed rate of return in all but one of the past fifteen years and have been lower than the allowed rate of return for the regulated entity in all of the past fifteen years.

Q. WHAT WOULD THE DCF MODEL YIELD AS AN EXPECTED RETURN ON EQUITY FOR DELTA?

A. The results of the DCF analysis for Delta are shown in Exhibits MJB-14 and MJB-15. The high and low stock prices for the year and the most recent annual dividend for the DCF calculation were obtained from the <u>Value Line Investment Survey - Small and Mid-Cap Edition</u>, March 12, 2010 (Exhibit MJB-16). Even though the <u>Value Line Investment Survey</u> for large companies reports forecasted future dividend growth rates for companies for the period 2006-2008 to 2013-2015, the <u>Value Line Investment Survey - Small and Mid-Cap Edition</u> does not report a forecasted dividend growth rate for the companies in the small-cap and mid-cap edition, which includes Delta. I ultimately used two growth rates in the DCF calculations for Delta. The first growth rate that I used in developing Exhibit MJB-14 was the 5-year average dividend growth rate for the panel of eleven natural gas distribution utilities reported in Exhibit MJB-9. I used the entire Edward Jones panel in order to avoid subjective judgments regarding the elimination of potential outliers.

The second growth rate that I used in the DCF calculations was the average of the forecasted dividend growth rates 2013 through 2015 for the eight large companies in the Edward Jones panel that were covered by the Value Line Investment Survey. The average dividend growth rate for the eight natural gas distribution companies covered by the large company edition of Value Line was 3.93%, and this is the growth rate that was used in the DCF calculations in Exhibit MJB-15.

The high and low annual stock prices during 2009 were used in calculating a range of estimated returns in the DCF analysis. Use of the high stock price in the DCF analysis in Exhibit MJB-14 with an average growth rate of 4.7% resulted in an estimated ROE of 9.00%, and use of the low stock price in the DCF analysis resulted in an estimated ROE of 11.63%. Use of the high stock price in the DCF analysis in Exhibit MJB-15 with an average growth rate of 3.93% resulted in an estimated ROE of 8.23%, and use of the low stock price in the DCF analysis resulted in an estimated ROE of 10.87%.

Q. CAN THESE CALCULATED RETURNS ON EQUITY USING THE DCF MODEL BE APPLIED TO BOOK VALUE CAPITALIZATION?

A. No. The DCF calculations in Exhibits MJB-14 and MJB-15 that resulted in the estimates of 9.00%, 11.63%, 8.23% and 10.87% for return on equity were made using the current stock price, and so these returns on equity are meaningful only when applied to market capitalization. As explained above, if the DCF model indicated a return on equity of 8% and the current stock price used to calculate this return on equity was $25, this tells us that shareholders are expecting an 8% return on equity in return for their $25 investment in the stock. They are not expecting an 8% return on the book value capitalization of the company, which is generally much lower and has little or no relationship to the market value of the stock. If the returns on equity calculated using the DCF formula are to be applied to the book value of equity, further calculations are necessary.

In Exhibit MJB-14, the estimated returns on equity calculated using the high and low stock prices are multiplied by the market capitalization calculated at the high and low stock prices to obtain the actual dollars that shareholders expect to receive annually from their investment. The market capitalization was calculated by multiplying the high and low stock price by the number of outstanding shares of stock, which for Delta was 3,327,573 shares. To convert this to a return on equity that could be applied to book capitalization, it is necessary to divide the actual dollars that shareholders expect to receive annually from their investment by Delta's book value of equity. In Exhibit MJB-14, these calculations resulted in returns on equity that could be appropriately applied to Delta's book value capitalization of 15.08% at the high stock price and 12.08% at the low stock price. Similar calculations in Exhibit MJB-15 resulted in returns on equity that could be appropriately applied to Delta's book value capitalization of 13.79% at the high stock price and 11.28% at the low stock price.

Q. DO THESE CALCULATIONS SEEM REASONABLE?

A. Yes. In fact, making the conversion from an ROE that should be applied to the value of market equity to an ROE that should be applied to book equity resolves a number of paradoxes that result from applying the ROE estimates from the DCF formula directly to the book equity component of Delta's capitalization. One thing that has always concerned me in performing DCF calculations was that the high stock price resulted in a lower calculated ROE than the low stock price. Looking at Exhibit MJB-14, the high stock price of $29.80 resulted in an ROE estimate of 9.00% while the low stock price of $18.46 resulted in an ROE estimate of 11.63%. This says that an investor would be willing to pay $29.80 for an investment generating a return on equity of 9.00% while he would only be willing to pay $18.46 for an investment generating a return on equity of 11.63%. This simply doesn't make sense and helps to illustrate that these calculated returns on equity should not be applied directly to book equity, which is $59,164,248 in this proceeding. An 11.63% return on book equity would be $6,880,802 annually while a 9.00% return on book equity would be $5,324,782 annually. A rational investor is not likely to pay $29.80 per share for an investment only generating $5,324,782 annually while paying $18.46 per share for an investment generating $6,880,802 annually.

However, this does make sense if these calculated ROEs are applied to market capitalization. In Exhibit MJB-14, the ROE of 9.00% calculated using the high stock price is applied to the market capitalization of $99,161,675 and the result is an annual dollar flow of $8,919,892 that shareholders expect from this investment. Similarly, the ROE of 11.63% calculated using the low stock price is applied to the market capitalization of $61,426,998, which was also calculated using the low stock price, and the result is an annual dollar flow of $7,146,362 that shareholders expect from this investment. This makes sense. Investors would be willing to pay a higher price for a stock that generated a larger dollar flow of returns and a lower stock price for an investment that generated a lower dollar flow of returns. This sensible result does not occur unless the ROEs calculated using DCF are adjusted in a way that allows them to be applied to book equity, as was done in Exhibits MJB-14 and MJB-15.

Q. IS IT NECESSARY TO APPLY AN ESTIMATED RETURN ON EQUITY IN A MANNER THAT IS CONSISTENT WITH THE WAY THAT IT IS CALCULATED?

A. Yes. As discussed above, the DCF calculation determines what shareholders require from a company in terms of present and future dividends relative to the <u>current market price</u> of the company's stock. Thus, returns on equity estimated in this manner must be applied to the market capitalization which is also calculated using the current market price of the stock. The DCF methodology does not determine what shareholders require from a company in terms of present and future dividends relative to the company's book value of equity. Thus application of ROEs estimated using the DCF methodology directly to a company's book value of equity or rate base is an inconsistent and an inappropriate application of these estimates. It is taking an estimate generated for one purpose and using it for a completely different and unrelated purpose. The ROE estimates calculated using the DCF methodology can only be applied to book value equity after converting them for such use as shown in Exhibits MJB-14 and MJB-15.

Q. WHAT WOULD THE CAPITAL ASSET PRICING MODEL ("CAPM") YIELD AS AN EXPECTED RETURN ON EQUITY FOR DELTA?

A. The CAPM approach could be utilized to estimate the return on equity for Delta. The basic CAPM formula is:

$$K = R_f + \beta\,(R_m - R_f) + S$$

where:

K = the prospective market cost of equity for a specific investment,

β = the company specific beta coefficient,

R_f = the risk free rate of return (usually U.S. Treasury bonds),

R_m = the overall stock market return,

$R_m - R_f$ = the equity risk premium, and

S = Size premium

The addition of a size premium is necessary to account for the return in excess of that predicted by CAPM which increases as one moves from the largest companies in decile 1 to the smallest in decile 10. The excess return is especially pronounced for micro-cap stocks (deciles 9 - 10). This size phenomenon has prompted a revision of CAPM, which includes a size premium (<u>Ibbotson SBBI 2010 Valuation Yearbook</u>, Morningstar Inc., p. 90).

The <u>Value Line Investment Survey - Small and Mid-Cap Edition</u> of March 12, 2010 (Exhibit MJB-16) provided an estimate for β of 0.65 for Delta. Ibbotson's <u>2010 Valuation Yearbook</u> calculated an estimated return in excess of CAPM of 4.91% for companies in category 10x. This percentage was calculated as the difference between large company stock total returns minus long-term government bond returns for the period 1926 through 2009. The interest rate on 20-Year U.S. Treasury bonds was 4.48% on February 1, 2010 as reported by FRED® [Federal Reserve Economic Data] available on the Federal Reserve Bank of St. Louis web site (Exhibit MJB-17). With an interest rate on 20-Year U.S. Treasury bonds of 4.48%, a beta coefficient of 0.65, and a size premium of 4.91%, the Capital Asset Pricing Model produces an estimated return on equity of 13.745% for Delta, which is calculated as shown in Exhibit MJB-18.

Q. WHAT RATE OF RETURN ON EQUITY WOULD THE RISK PREMIUM ANALYSIS INDICATE WAS APPROPRIATE?

A. Ibbotson's 2010 Valuation Yearbook calculated an estimated return above the riskless rate for companies in category 10x, which would include Delta, of 9.69 %. This premium was calculated by subtracting long-term government bond returns from micro-cap stock total returns for companies in category 10x for the period 1926 to 2005. This estimate of the risk premium is calculated using a past average of ex-post risk premiums over a sufficiently long period of time to include several ups and downs in dividend yields and provides a good estimate of the future risk premium. The interest rate on 20-Year U.S. Treasury bonds was 4.48% on February 1, 2010 as reported by FRED® [Federal Reserve Economic Data] available on the Federal Reserve Bank of St. Louis web site (Exhibit MJB-17). Adding the long-horizon risk premium of 9.69% to the 20-year U.S. Treasury bond yield of 4.48% produces a return on equity of 14.17%, as shown in Exhibit MJB-19.

Q. DID YOU ALSO DIRECTLY APPLY THE STANDARD SUGGESTED BY THE U.S. SUPREME COURT OF CALCULATING THE APPROPRIATE RATE OF RETURN ON EQUITY FOR ENTITIES WITH CORRESPONDING RISK?

A. Yes. As discussed above, it is important to note that the U.S. Supreme Court did not limit the return on equity to being commensurate with other utilities. It stated that the return on equity should be commensurate with other companies having corresponding risk. The estimated beta value measures a stock's sensitivity to the market as a whole and is an objective measure of the systematic risk for a stock. Systematic risk is unavoidable, is common to all risky securities, and cannot be eliminated through diversification. Using beta as an objective measure of a stock's risk, I did a search using the Value Line

Investment Analyzer for companies that had beta values of 0.65, which is the same beta value as reported for Delta in the Value Line Investment Survey - Small and Mid Cap Edition of March 12, 2010. This resulted in the 201 companies shown in Exhibit MJB-20. For the year 2009, which was generally regarded as a year in which the U.S. economy was in recession, the average return on common equity for these 201 companies was 12.0%. One advantage that this panel of 201 companies has is that the returns on equity for these companies have not been determined by regulatory commissions, but by the market. This helps to avoid any tendency by regulators to "follow the leader" and to allow rates of return on equity that are similar to those that other regulatory commissions are allowing. Thus, a return on equity of 12.0% for Delta would be consistent with the U.S. Supreme Court's guidance that a company should be allowed to earn a return that is commensurate with entities of corresponding risk. In fact, because 2009 was a year when the U.S. economy was in recession, a return in excess of 12.0% would likely be appropriate.

Q. WHAT IS A REASONABLE RANGE FOR THE RETURN ON EQUITY IN THIS PROCEEDING?

A. Based on the above analysis, a reasonable range for return on equity in this proceeding would be between 11.28% and 15.08% as summarized in the table below.

Method	**ROE Range**	
	High	**Low**
DCF (5-Year Average Panel Growth)	15.08%	12.08%
DCF (Forecasted Average Panel Growth)	13.79%	11.28%
CAPM	13.745%	13.745%

Risk Premium	14.17%	14.17%
Companies of Corresponding Risk	12.0%	12.0%

These estimates do not make any leverage adjustment for Delta's lower than average percentage of equity in its total capitalization compared to other natural gas distribution companies in the panel, which would have the effect of increasing these return on equity estimates. As demonstrated in Exhibit MJB-13, Delta's equity percentage is the second lowest in the panel which exacerbates reductions in its earned rate of return compared to other natural gas distribution utilities if Delta experiences any revenue shortfalls. This would make Delta a riskier investment which could be adjusted by adding a leverage adjustment to the estimated return on equity. However, no leverage adjustment is being proposed at this time.

Q. WHAT RETURN ON EQUITY DO YOU RECOMMEND BE UTILIZED IN CALCULATING THE REVENUE REQUIREMENT IN THIS PROCEEDING?

A. I recommend using a 12.0% return on equity in this proceeding, which is the return on equity based on the average return on equity for the 201 companies in the Value Line Survey that have the same risk as Delta as measured by a beta of 0.65. This recommended return on equity meets the U.S. Supreme Court's standard that a utility should be allowed to earn a return that is commensurate with returns on investments in other enterprises having corresponding risks. Beta is an objective and quantifiable measure of risk and the analysis in Exhibit MJB-20 used only companies with a beta identical to Delta's. This approach also has the advantage of developing an estimated return on equity that is independent of state utility regulatory decisions, which as described above, can result in a self fulfilling prophecy. The 12.0% that I am recommending is well within the reasonable range as indicated by my analysis. In fact, my recommendation of 12.0% is near the low end of the range of reasonableness for an allowed return on equity. In determining the appropriate return on equity for Delta, the Commission needs to consider that Delta is different than the four other major investor owned utilities that the Commission regulates. Delta is the smallest of the five companies with one of the lowest equity ratios in the industry. The size premium for small companies is well documented and has been calculated based on a data set that covers a number of economic cycles that include both wars and a depression. In deciding on the appropriate return on equity for Delta, it is important for the Commission to note that Delta has only earned its allowed rate of return once in the past 15 years (Exhibit MJB-10). Additionally, Delta's low percentage of equity compared to other natural gas distribution companies makes it harder for Delta to earn any rate of return allowed by the Commission as illustrated in Exhibit MJB-13. This is particularly true when combined with factors such as the negative impact that Delta experiences from financing deferred gas costs with no interest recovery. After analyzing all of the relevant factors, I believe that 12.0% is a reasonable return on equity for Delta in this proceeding if this return on equity is applied to the book equity component of Delta's capitalization.

Q. DOES THE RETURN ON EQUITY THAT YOU RECOMMEND PRODUCE A REASONABLE RESULT?

A. Yes. The 2010 Valuation Yearbook reports that the average rate of return for companies similar to Delta (category 10x which is the second subdivision of the smallest decile of companies) was 19.78% for the period 1926-2009 (Ibbotson SBBI 2010 Valuation Yearbook, Morningstar Inc., p. 92). This source goes on to state that:

> Finnerty and Leistikow perform more econometrically sophisticated tests of mean reversion in the equity risk premium. Their tests demonstrate that – as we suspected from our simpler tests – the equity risk premium that was realized over 1926 to present was almost perfectly free of mean reversion and had no statistically identifiable time trends. (Ibbotson SBBI 2010 Valuation Yearbook, Morningstar Inc., p. 59)

This randomness of year to year returns makes a long term average based on a data set that covers a number of economic cycles that include both wars and a depression one of the best estimates of return on equity that is available to us.

Q. HOW DOES THE INTEREST COVERAGE FOR DELTA COMPARE TO THE INTEREST COVERAGE FOR THE OTHER NATURAL GAS DISTRIBUTION COMPANIES IN THE EDWARD JONES PANEL IF THE COMMISSION WERE TO ALLOW DELTA A 12.0% RETURN ON EQUITY?

A. Exhibit MJB-6 shows the interest coverage for the 11 natural gas distribution companies in the panel reported by Edward Jones, which is calculated by dividing net income plus interest on long term debt by the interest on long term debt. Delta has an interest coverage of 2.54x, which is second lowest in the panel of natural gas distribution utilities covered in the report. The mean interest coverage for the panel is 4.18x. If the revenue requirement for Delta is determined based on a 12.0% return on equity and based on the capital structure in this proceeding, the resulting interest coverage would be 2.60x. As can be seen from Exhibit MJB-6, the resulting interest coverage from using a 12.0% rate of return would still be the second lowest in the panel and well below the mean coverage for the eleven natural gas distribution companies included in the Edward Jones report. Based on the resulting level of interest coverage compared to natural gas distribution industry averages, I believe that application of the recommended 12.0% rate of return on equity to the existing capital structure is reasonable. It would take even a higher rate of return on equity to produce a level of interest coverage and an equity ratio that is more representative of the other companies in the panel of natural gas distribution companies. The revenue requirement that would result from utilizing the 12.0% return on equity that I recommend would be a start to increasing Delta's equity ratio to a level more appropriate for a natural gas distribution company of Delta's size, and to increasing the interest coverage to a level that is closer to the industry average. However, even when this recommended ROE is placed into effect, it will take several years before there is significant improvement in these key financial measures.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

Exhibit MJB-1

Prior Testimony of Dr. Martin J. Blake

Federal Energy Regulatory Commission

ER92-533	LG&E's open transmission access and authority to charge market-based rates for its generation.
ER94-1380	The first comparability tariff approved by the FERC.
ER97-4345	A market power analysis that was filed in support of OGE Energy Resources, Inc.'s request for the authority to charge market based rates.
ER98-511	A market power analysis that was filed in support of Oklahoma Gas and Electric Co.'s request for the authority to charge market based rates.
ER99-51	An affidavit in support of Commonwealth Edison Co.'s request for authority to charge cost based rates to its affiliates.
ER01-1938	Testimony in support of Southern Indiana Gas and Electric Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
ER02-708	Testimony in support of Central Illinois Power Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
NJ03-2	Testimony in support of Southern Illinois Power Company's request for a revision in ancillary service rates
EL03-53	Testimony regarding the calculation of avoided cost for a qualifying facility interconnecting with a cooperative
EL02-111	Testimony regarding the process for developing a combined transmission service rate that would apply to the combined Midwest ISO and PJM footprint

Arkansas Public Service Commission

96-360-U	Direct and rebuttal testimony for Oklahoma Gas and Electric regarding recovery of stranded costs by Entergy Arkansas, Inc.

California Public Utility Commission

90-12-018 (phase 5)	Direct and rebuttal testimony for Southern California Edison Company concerning the reasonableness of contracting by Southern California Edison with Integrated Energy Group ("IEG") to provide marketing services to Southern California Edison and the reasonableness of the resulting marketing services performed by IEG.

Colorado

C08-0559	Provide an independent review, assessment and recommendation concerning Public Service Company of Colorado's Application and request for the Commission to approve the Company's 2007 Colorado Resource Plan ("2007 CRP") and to review supporting testimony in this proceeding as it relates to the retirement of Cameo Units 1 and 2 and Arapahoe Units 3 and 4.
02S-594E	Direct and surrebuttal testimony regarding pro forma adjustments to the revenue requirement in Aquila Networks-WPC rate case.
03S-539E	Testimony regarding the use of zero intercept methodology to allocate distribution costs and determine an appropriate customer charge in an Aquila Networks-WPC rate case.
07A-447E	Testimony regarding Public Service Company of Colorado's Integrated Resource Plan.

Illinois Commerce Commission

98-0013 and 98-0035	Testimony regarding non-discrimination with regard to affiliate transactions for electric utilities. I sponsored ComEd's proposed affiliate transactions rules and suggested some basic principles that the Illinois Commerce Commission should follow in developing rules and regulations for ensuring non-discrimination and non-cross subsidization in transactions with affiliated and unaffiliated alternative retail electric suppliers ("ARES").
98-0036	Testimony in a rulemaking to develop rules and regulations for assessing and assuring the reliability of the transmission and distribution systems as a part of electric utility restructuring in Illinois.
98-0147 and 98-0148	Testimony concerning standards of conduct and rules for functional separation. I sponsored ComEd's proposed standards of conduct and functional separation rules.

07-0572 Testimony in a reconciliation proceeding concerning the prudence and recovery of the costs of gas injections and withdrawals from the Hillsboro storage field.

Kentucky Public Service Commission

90-158 An LG&E rate case.

92-494 An LG&E biennial fuel adjustment clause review.

93-150 An application for approval of a DSM cost recovery mechanism and a set of initial programs.

94-332 An application for an environmental cost recovery mechanism.

92-494-B Testimony regarding the confidentiality of coal bid data.

95-455 A biannual review of the environmental cost recovery mechanism.

91-423 Participation in the conference with Commission staff and intervenors to review LG&E's first integrated resource plan.

Other Several fuel adjustment clause proceedings on behalf of LG&E.

98-489 Testimony on behalf of Blazer Energy Corp. in an application for an adjustment in their natural gas rates.

99-046 Direct and rebuttal testimony regarding Return on equity in support of Delta Natural Gas Company's request for an adjustment in rates

04-00067 Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates

07- **00089** Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates

Nevada Public Utility Commission

01-10001 Direct testimony on behalf of Shareholders Association to support Nevada Power Company's request for return on equity

New Mexico Public Utility Commission

2797 Direct and rebuttal testimony in a general rate case for Plains Electric Generation and Transmission Cooperative, Inc.

Virginia State Corporation Commission

PUE-2008-00076 Direct and Rebuttal testimony regarding rate design for Northern Neck Electric Cooperative

U.S. District Court, District of New Mexico

CIV-08-00026 Reviewed the Expert Report filed by Gary L. Groninger and provided rebuttal testimony regarding whether a decision that was made by the Arkansas River Power Authority (ARPA) was prudent.

Oklahoma Corporation Commission

PUD 960000116 Testimony in an Oklahoma Gas and Electric Company rate case, including rebuttal of intervenor and staff proposals to disallow certain marketing, advertising, economic development and research and development expenses.

PUD 200300226 Testimony in an Oklahoma Gas and Electric Company case regarding the prudence of natural gas transportation and storage contracts

Indiana Utility Regulatory Commission

41884 Direct and rebuttal testimony to support a request by eleven gas local distribution companies for switching from a quarterly gas cost adjustment mechanism to a monthly gas cost adjustment mechanism

42027 Direct testimony in support of a transfer of functional control of transmission assets from electric utilities in Indiana to the Midwest System Operator, Inc.

Iowa District Court for Hamilton County

No. LACV025993 Testimony that net metering was not appropriate for making payments to a wind generator. When a utility sells electric energy to a customer, it is charging a retail rate that recovers the cost of distribution, transmission and generation service. When a customer sells electric energy to a utility, it is selling only generation service. The customer cannot sell distribution and transmission service to a utility, as the customer does not own these assets. Net metering is a subsidy to the wind generator that is paid by other customers of the utility and paying the customer for generation service on the basis of a retail rate that includes recovery of distribution and transmission costs is not appropriate.

Ranking By Total Capitalization **Exhibit MJB-2**

	12 Months Ending		Total Cap (000)	Percent Equity
Atmos Energy Corp.	9/30/2009	$	4,419,790	49.3%
AGL Resources, Inc.	9/30/2009	$	4,032,000	42.6%
Piedmont Natural Gas Company	10/31/2009	$	2,026,460	45.8%
Northwest Natural Gas Company	9/30/2009	$	1,349,764	47.5%
New Jersey Resources, Inc.	9/30/2009	$	1,295,128	53.3%
South Jersey Industries, Inc.	9/30/2009	$	1,042,124	50.6%
Laclede Group	9/30/2009	$	1,036,070	49.9%
WGL Holdings,Inc.	9/30/2009	$	195,144	56.2%
Delta Natural Gas Company	9/30/2009	**$**	**125,675**	**45.7%**
RGC Resources, Inc.	9/30/2009	$	72,800	61.5%
Energy Inc	9/30/2009	$	54,172	57.6%
Mean		$	1,582,557	50.9%
Median		$	1,295,128	49.9%

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Information, Edward Jones Co., December 31, 2009

Ranking By Equity Percentage **Exhibit MJB-3**

	12 Months Ending		Total Cap (000)	Percent Equity
RGC Resources, Inc.	9/30/2009	$	72,800	61.5%
Energy Inc	9/30/2009	$	54,172	57.6%
WGL Holdings,Inc.	9/30/2009	$	195,144	56.2%
New Jersey Resources, Inc.	9/30/2009	$	1,295,128	53.3%
South Jersey Industries, Inc.	9/30/2009	$	1,042,124	50.6%
Laclede Group	9/30/2009	$	1,036,070	49.9%
Atmos Energy Corp.	9/30/2009	$	4,419,790	49.3%
Northwest Natural Gas Company	9/30/2009	$	1,349,764	47.5%
Piedmont Natural Gas Company	10/31/2009	$	2,026,460	45.8%
Delta Natural Gas Company	9/30/2009	**$**	**125,675**	**45.7%**
AGL Resources, Inc.	9/30/2009	$	4,032,000	42.6%
Mean		$	1,582,557	50.9%
Median		$	1,295,128	49.9%

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Information, Edward Jones Co., December 31, 2009

Ranking By Return On Common Equity **Exhibit MJB-4**

AGL Resources Inc.	13.2%
Piedmont Natural Gas Company, Inc.	13.0%
Laclede Group, Inc.	12.4%
Northwest Natural Gas Company	12.0%
RGC Resources, Inc.	10.9%
WGL Holdings, Inc.	10.8%
South Jersey Industries, Inc.	10.7%
Energy, Inc.	10.4%
Atmos Energy Corp.	8.9%
Delta Natural Gas Company, Inc.	**7.5%**
New Jersey Resources Corporation	3.7%
Mean	10.3%

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Information,
Edward Jones Co., December 31, 2009

Ranking By Dividend Payout

Exhibit MJB-5

New Jersey Resources Corporation	194
Delta Natural Gas Company, Inc.	**97**
Energy, Inc.	68
Piedmont Natural Gas Company, Inc.	64
Atmos Energy Corp.	63
South Jersey Industries, Inc.	63
WGL Holdings, Inc.	61
RGC Resources, Inc.	59
AGL Resources Inc.	58
Northwest Natural Gas Company	54
Laclede Group, Inc.	53
Mean	76

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Information, Edward Jones Co., December 31, 2009

Ranking By Pre-Tax Interest Coverage **Exhibit MJB-6**

Energy, Inc.	5.83
WGL Holdings, Inc.	5.31
RGC Resources, Inc.	5.13
South Jersey Industries, Inc.	5.02
AGL Resources Inc.	4.63
Piedmont Natural Gas Company, Inc.	4.52
Laclede Group, Inc.	4.20
Northwest Natural Gas Company	3.99
Atmos Energy Corp.	2.84
Delta Natural Gas Company, Inc.	**2.54**
New Jersey Resources Corporation	1.98
Mean	4.18

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Information, Edward Jones Co., December 31, 2009

Ranking By Earnings Per Share Growth **Exhibit MJB-7**

Energy, Inc.	NA
Northwest Natural Gas Company	16.9%
RGC Resources, Inc.	14.1%
Piedmont Natural Gas Company, Inc.	12.1%
AGL Resources Inc.	8.1%
Atmos Energy Corp.	4.0%
WGL Holdings, Inc.	2.6%
Laclede Group, Inc.	-18.4%
South Jersey Industries, Inc.	-20.2%
Delta Natural Gas Company, Inc.	**-44.8%**
New Jersey Resources Corporation	-75.3%
Mean	-10.1%

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Informa
Edward Jones Co., December 31, 2009

Ranking By 5-Year Total Return **Exhibit MJB-8**

Energy, Inc.	173.7%
South Jersey Industries, Inc.	69.9%
Northwest Natural Gas Company	59.3%
New Jersey Resources Corporation	52.4%
RGC Resources, Inc.	41.4%
Piedmont Natural Gas Company, Inc.	39.6%
AGL Resources Inc.	37.1%
Atmos Energy Corp.	35.9%
WGL Holdings, Inc.	35.3%
Laclede Group, Inc.	34.6%
Delta Natural Gas Company, Inc.	**32.5%**
Mean	55.6%

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Informa
Edward Jones Co., December 31, 2009

Ranking By 5-Year Dividend Growth

Exhibit MJB-9

Energy, Inc.	NM
South Jersey Industries, Inc.	9.2%
New Jersey Resources Corporation	8.4%
AGL Resources Inc.	8.2%
Northwest Natural Gas Company	5.0%
Piedmont Natural Gas Company, Inc.	4.7%
Laclede Group, Inc.	3.0%
WGL Holdings, Inc.	2.5%
RGC Resources, Inc.	2.3%
Delta Natural Gas Company, Inc.	**2.0%**
Atmos Energy Corp.	1.6%
Mean	4.7%

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Information, Edward Jones Co., December 31, 2009

Exhibit MJB - 10
Historical Comparison of Allowed and Actual ROE
Delta Natural Gas Company

	Return on Equity[1]	Allowed ROE	Difference	
1995	8.50%	Black box settlement in last rate case		
1996	11.30%	Black box settlement in last rate case		
1997	5.80%	Black box settlement in last rate case		
1998	8.20%	11.60%	-3.40%	New Rates Effective Jan. 1998
1999	7.20%	11.60%	-4.40%	
2000	11.10%	11.60%	-0.50%	New Rates Effective Jan. 2000
2001	11.10%	11.60%	-0.50%	
2002	10.60%	11.60%	-1.00%	
2003	8.60%	11.60%	-3.00%	
2004	7.90%	10.50%	-2.60%	New Rates Effective Oct. 2004
2005	9.80%	10.50%	-0.70%	
2006	9.50%	10.50%	-1.00%	
2007	9.70%	10.50%	-0.80%	New Rates Effective Nov 2007
2008	11.90%	10.50%	1.40%	
2009	8.80%	10.50%	-1.70%	
Mean	**9.33%**	**11.05%**		

1: The Value Line Investment Survey - Small and Mid-Cap Edition, March 12, 2010

Exhibit [illegible]B-11

Historical Earned Returns on Equity for the Consolidated Company and the Regulated Entity

	Regulated Billed Basis Calendar Year						Consolidated Unbilled Basis Calendar Year		
Year	Net Income	Capital	Earned ROE	Allowed ROE	Difference		Net Income	Capital	Earned ROE
2000						New rates effective Jan. 2000			
2001									
2002							3,694,390	44,030,321	8.4%
2003	2,124,142	44,977,907	4.7%	11.6%	-6.9%		5,961,061	49,055,982	12.2%
2004	2,005,904	46,376,806	4.3%	10.5%	-6.2%	New rates effective Oct. 2004	5,649,011	51,524,275	11.0%
2005	2,845,404	48,958,684	5.8%	10.5%	-4.7%		4,550,016	52,736,947	8.6%
2006	2,035,508	50,633,040	4.0%	10.5%	-6.5%		5,098,611	54,200,448	9.4%
2007	2,354,763	52,015,805	4.5%	10.5%	-6.0%	New rates effective Oct. 2007	6,687,746	57,178,017	11.7%
2008	3,986,201	55,077,190	7.2%	10.5%	-3.3%		5,058,380	58,437,146	8.7%
2009	2,851,691	56,492,338	5.0%	10.5%	-5.5%				

Delta Natural Gas Capital Structure **Exhibit MJB - 12**
December 31, 2009

	Dollar Amount	Percent of Total Capitalization	Cost Rates	Weighted Cost of Capital
Equity	$ 56,492,338	44.49%	12.000%	5.339%
Long Term Debt	$ 58,459,000	46.04%	6.830%	3.145%
Short Term Debt	$ 12,015,728	9.46%	2.019%	0.191%
Total	$ 126,967,066	100.00%		8.675%

Exhibit MJB - 13
Examples of the Impact of Leverage on Actual Return on Equity

Example 1

	Capitalization	Percent of Cap	Cost Rates	Return Element in Dollars
Equity	$56,492,338	44.5%	10.50%	$ 5,931,695
Debt	$70,474,728	55.5%	6.74%	$ 4,749,997
	$126,967,066	100.0%		$ 10,681,692

Assume a shortfall in earnings of: $ 3,000,000

Actual Return on Equity = $4,971,695 / $56,492,338
= 5.19%

Example 2

	Capitalization	Ratios	Cost Rates	Return Element in Dollars
Equity	$64,626,236	50.9%	10.50%	$ 6,785,755
Debt	$62,340,829	49.1%	6.74%	$ 4,201,772
	$126,967,066	100.0%		$ 10,987,527

Assume a shortfall in earnings of: $ 3,000,000

Actual Return on Equity = $5,825,755 / $64,626,236
= 5.86%

Example 3

	Capitalization	Ratios	Cost Rates	Return Element in Dollars
Equity	$78,084,745	0.6150	10.50%	$ 8,198,898
Debt	$48,882,320	0.3850	6.74%	$ 3,294,668
	$126,967,066	100.0%		$ 11,493,567

Assume a shortfall in earnings of: $ 3,000,000

Actual Return on Equity = $7,238,898 / $78,084,745
= 6.66%

Exhibit MJB
Results of DCF Model for Delta Natural Gas Company
Using 5-Year Average Growth Rate for Edward Jones Natural Gas Distribution Utility Panel

		Variable Name	
2009 Annual Dividend	$1.28	D	1
High Price During 2009	$29.80	P	1
Low Price During 2009	$18.46	P	1
Avg. 5- Year Dividend Growth Rate of Edward Jones Panel	4.70%	g	2
Shares Outstanding	3,327,573		1
Earnings per Share in 2009	$1.58		1
Book Equity	$ 59,164,248		1

Using the DCF formula: **ROE = D/P + g**

ROE Based on the 2009 High Stock Price

ROE = (1.28 / 29.80) + .047 = 9.00%

ROE Based on the 2009 Low Stock Price

ROE = (1.28 / 18.46) + .047 = 11.63%

Return on Book Equity 2009 High Stock Price

$8,919,892/ $59,164,248 = 15.08%

Return on Book Equity 2009 Low Stock Price

$7,146,362 / $59,164,248 = 12.08%

Market Capitalization 2009 High Stock Price

3,327,573 x 29.80 = $99,161,675

Market Capitalization 2009 Low Stock Price

3,327,573 x 18.46 = $61,426,998

Expected Shareholder Returns High Stock Price

$99,161,675 x .0900 = $8,919,892

Expected Shareholder Returns Low Stock Price

$61,426,998 x .1163 = $7,146,362

1. The Value Line Investment Survey - Small and Mid-Cap Edition, March 12, 2010

2. Natural Gas Industry Summary Quarterly Financial & Common Stock Information, Edward Jones Co., December 31, 2009, p. 29

Exhibit MJB
DCF Results for Delta Naturaı Gas Company
Using Average Growth Rate for the Eight Comapnies in the Value Line Survey

		Variable Name	Source
2009 Annual Dividend	$1.28	D	1
High Price During 2009	$29.80	P	1
Low Price During 2009	$18.46	P	1
Average Growth Rate	3.93%	g	1
Shares Outstanding	3,327,573		1
Earnings per Share in 2009	$1.58		1
Book Equity	$ 59,164,248		1

Company	Forecasted Dividend Growth Rate 2006-2008 to 2013 to 2015
AGL Resources Inc.	2.50%
Atmos Energy Corp.	2.00%
Laclede Group, Inc.	2.45%
New Jersey Resources Corporation	5.50%
Northwest Natural Gas Company	6.00%
Piedmont Natural Gas Company, Inc.	3.50%
South Jersey industries, Inc.	6.50%
WGL Holdings, Inc.	3.00%
Average	3.93%

Using the DCF formula: ROE = D/P + g

ROE Based on the 2009 High Stock Price

ROE = (1.28 / 29.80) + .0393 = 8.23%

ROE Based on the 2009 Low Stock Price

ROE = (1.28 / 18.46) + .0393 = 10.87%

Market Capitalization 2009 High Stock Price

3,327,573 x 29.80 = $99,161,675

Market Capitalization 2009 Low Stock Price

3,327,573 x 18.46 = $61,426,998

Expected Shareholder Returns High Stock Price

$99,161,675 x .0823 = $8,157,587

Expected Shareholder Returns Low Stock Price

$61,426,998 x .1087 = $6,674,142

Return on Book Equity 2009 High Stock Price

$8,157,587 / $59,164,248 = 13.79%

Return on Book Equity 2009 Low Stock Price

$6,674,142 / $59,164,248 = 11.28%

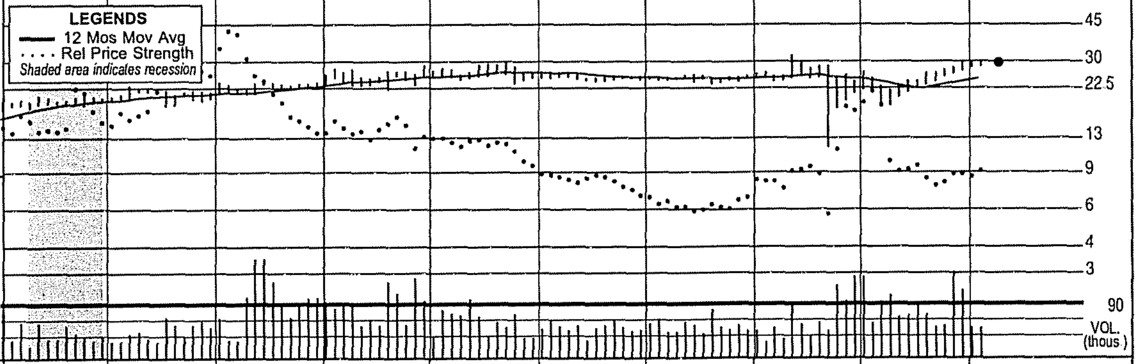
1. The Value Line Investment Survey - Small and Mid-Cap Edition, March 12, 2010

DELTA NAT. GAS NDQ–DGAS

RECENT PRICE	TRAILING P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
29.55	19.2	1.06	4.4%	VALUE LINE

RANKS	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010/2011	
	20.99	23.08	24.10	28.75	30.00	26.82	26.08	32.19	29.80	30.00	High
	17.69	18.50	21.00	22.02	23.60	24.11	23.50	11.70	18.46	27.96	Low

PERFORMANCE	3	Average
Technical	3	Average
SAFETY	2	Above Average
BETA .65		(1.00 = Market)
Financial Strength	B+	
Price Stability	95	
Price Growth Persistence	50	
Earnings Predictability	70	



© VALUE LINE PUBLISHING, INC.	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010/2011
SALES PER SH	28.36	22.11	21.59	24.74	26.06	36.01	29.96	34.18	31.84	
"CASH FLOW" PER SH	3.08	3.16	2.65	2.65	2.86	2.94	3.19	3.49	2.89	
EARNINGS PER SH	1.47	1.45	1.49	1.20	1.55	1.55	1.62	2.08	1.58	***1.65*** [A,B]***/NA***
DIV'DS DECL'D PER SH	1.14	1.16	1.18	1.18	1.18	1.20	1.22	1.24	1.28	
CAP'L SPENDING PER SH	2.83	3.72	2.90	2.80	1.65	2.39	2.47	1.69	2.54	
BOOK VALUE PER SH	13.12	13.51	14.49	15.26	15.73	16.16	16.61	17.48	17.78	
COMMON SHS OUTST'G (MILL)	2.50	2.53	3.17	3.20	3.23	3.26	3.28	3.30	3.32	
AVG ANN'L P/E RATIO	12.3	14.1	14.5	20.1	16.8	16.9	15.5	12.3	15.0	***17.9/NA***
RELATIVE P/E RATIO	.63	.77	.83	1.06	.89	.91	.82	.74	.99	
AVG ANN'L DIV'D YIELD	6.3%	5.7%	5.5%	4.9%	4.5%	4.6%	4.9%	4.9%	5.4%	
SALES ($MILL)	70.8	55.9	68.4	79.2	84.2	117.3	98.2	112.7	105.6	***Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.***
OPERATING MARGIN	23.2%	29.3%	24.7%	21.2%	21.9%	16.2%	20.4%	19.6%	18.0%	
DEPRECIATION ($MILL)	4.0	4.4	4.5	4.7	4.3	4.6	5.2	4.7	4.4	
NET PROFIT ($MILL)	3.6	3.6	3.9	3.8	5.0	5.0	5.3	6.8	5.2	
INCOME TAX RATE	38.0%	38.2%	38.0%	38.1%	38.3%	36.6%	37.3%	37.8%	36.6%	
NET PROFIT MARGIN	5.1%	6.5%	5.8%	4.8%	5.9%	4.3%	5.4%	6.1%	4.9%	
WORKING CAP'L ($MILL)	d12.6	d15.3	d.2	d.7	.9	4.6	5.1	8.2	5.5	
LONG-TERM DEBT ($MILL)	49.3	48.6	53.4	53.0	52.7	58.8	58.6	58.3	57.6	
SHR. EQUITY ($MILL)	32.8	34.2	45.9	48.8	50.8	52.6	54.4	57.6	59.0	
RETURN ON TOTAL CAP'L	6.7%	6.6%	5.9%	5.6%	6.7%	6.7%	6.3%	7.6%	6.2%	
RETURN ON SHR. EQUITY	11.1%	10.6%	8.6%	7.9%	9.8%	9.5%	9.7%	11.9%	8.8%	
RETAINED TO COM EQ	2.5%	2.1%	1.6%	.2%	2.4%	2.1%	2.4%	4.8%	1.7%	
ALL DIV'DS TO NET PROF	78%	80%	81%	98%	76%	77%	75%	60%	81%	

[A]No. of analysts changing earn. est. in last 27 days: 0 up, 0 down, consensus 5-year earnings growth 3.0% per year. [B]Based upon one analyst's estimate.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	7.0%	-7.0%
"Cash Flow"	2.5%	-17.0%
Earnings	5.0%	-24.0%
Dividends	1.0%	3.0%
Book Value	3.5%	2.0%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
06/30/07	13.1	28.4	41.0	15.7	98.2
06/30/08	12.4	29.3	48.4	22.6	112.7
06/30/09	18.1	33.9	43.2	10.4	105.6
06/30/10	8.1	21.1			

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
06/30/06	d.18	.89	1.03	d.19	1.55
06/30/07	d.16	.73	1.12	d.07	1.62
06/30/08	d.25	.75	1.65	d.07	2.08
06/30/09	.08	.37	1.29	d.16	1.58
06/30/10	d.17	.58			

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2007	.305	.305	.31	.31	1.23
2008	.31	.31	.32	.32	1.26
2009	.32	.32	.325	.325	1.29
2010	.325				

INSTITUTIONAL DECISIONS

	1Q'09	2Q'09	3Q'09
to Buy	8	9	11
to Sell	9	9	6
Hld's(000)	615	568	588

ASSETS ($mill.)	2008	2009	12/31/09
Cash Assets	.3	.1	.1
Receivables	11.4	4.1	12.7
Inventory (Avg cost)	15.0	10.4	11.5
Other	7.3	4.8	6.9
Current Assets	34.0	19.4	31.2
Property, Plant & Equip, at cost	192.1	199.3	--
Accum Depreciation	67.7	70.7	--
Net Property	124.4	128.6	129.2
Other	12.4	14.5	14.6
Total Assets	170.8	162.5	175.0
LIABILITIES ($mill.)			
Accts Payable	12.2	4.7	6.3
Debt Due	8.0	4.9	13.2
Other	5.6	4.3	4.4
Current Liab	25.8	13.9	23.9

LONG-TERM DEBT AND EQUITY as of 12/31/09

Total Debt $70.5 mill. **Due in 5 Yrs.** NA
LT Debt $57.3 mill.
Including Cap. Leases NA
(49% of Cap'l)

Leases, Uncapitalized Annual rentals NA

Pension Liability $4 mill. in '09 vs. None in '08

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 3,327,573 shares
(51% of Cap'l)

INDUSTRY: Natural Gas (Div.)

BUSINESS: Delta Natural Gas Company, Inc. sells natural gas to approximately 37,000 retail customers on its distribution system in central and southeastern Kentucky. Its Regulated segment sells natural gas to its retail customers, primarily in 23 rural counties. This segment also transports gas to industrial customers on its system who purchase gas in the open market, as well as transports gas on behalf of local producers not on its distribution system. The company's Non Regulated segment purchases natural gas on the open market and from Kentucky producers, and resells this gas to industrial customers on its distribution system and to others not on its system. This segment also produces natural gas that is sold to Delgasco for resale. As of June 30, the company owned approximately 2,500 miles of natural gas gathering, transmission, distribution, storage, and service lines, as well as interests in oil and gas leases on 10,300 acres in Bell, Knox, and Whitley counties. Has 155 employees. Chairman, C.E.O. & President: Glenn R. Jennings. Inc.: KY. Address: 3617 Lexington Road, Winchester, KY 40391. Tel.: (859) 744-6171. Internet: http://www.deltagas.com.

L.Y.

March 12, 2010

TOTAL SHAREHOLDER RETURN

Dividends plus appreciation as of 2/28/2010

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
11.58%	16.40%	44.31%	37.61%	40.85%

Exhibit MJB-17
Interest Rates for 20-Year Treasury Bonds

Date	Interest Rate
2007-01-01	4.95%
2007-02-01	4.93%
2007-03-01	4.81%
2007-04-01	4.95%
2007-05-01	4.98%
2007-06-01	5.29%
2007-07-01	5.19%
2007-08-01	5.00%
2007-09-01	4.84%
2007-10-01	4.83%
2007-11-01	4.56%
2007-12-01	4.57%
2008-01-01	4.35%
2008-02-01	4.49%
2008-03-01	4.36%
2008-04-01	4.44%
2008-05-01	4.60%
2008-06-01	4.74%
2008-07-01	4.62%
2008-08-01	4.53%
2008-09-01	4.32%
2008-10-01	4.45%
2008-11-01	4.27%
2008-12-01	3.18%
2009-01-01	3.46%
2009-02-01	3.83%
2009-03-01	3.78%
2009-04-01	3.84%
2009-05-01	4.22%
2009-06-01	4.51%
2009-07-01	4.38%
2009-08-01	4.33%
2009-09-01	4.14%
2009-10-01	4.16%
2009-11-01	4.24%
2009-12-01	4.40%
2010-01-01	4.50%
2010-02-01	4.48%
Average	4.46%

Title:	20-Year Treasury Constant Maturity Rate
Series ID:	GS20
Source:	Board of Governors of the Federal Reserve System
Release:	H.15 Selected Interest Rates

Exhibit MJB - 18
Results of the CAPM Analysis
Delta Natural Gas Company

		Variable Name	*Data Source*
20 - Year U. S. Treasury Bond Yield	4.48%	Rf	1
Long - Horizon Expected Equity Risk Premium for Large Companies	6.70%	Rm - Rf	2
Calculated Beta Coefficient for Delta Natural Gas	0.65	B	3
Micro-Cap Size Premium for Delta	4.91%		4

Using the CAPM Formula ROE = Rf + B (Rm - Rf) + size premium
= 4.48 + 0.65(6.70) + 4.91 = 13.745

ROE Estimate Including Micro-Cap Size Premium = 13.7450%

Data Sources:

1. Yield for 20-Year Treasury Constant Maturity Rate, Feb 1, 2010
   Federal Reserve Bank of St. Louis Economic Research
2. Ibbotson 2010 SBBI Valuation Yearbook, Morningstar, Inc., 2010, p. 59
3. The Value Line Investment Survey - Small and Mid-Cap Edition, March 12, 2010
4. The Value Line Investment Survey - Small and Mid-Cap Edition, March 12, 2010, p. 92

Exhibit MJB - 19
Results of the Risk Premium Analysis
Delta Natural Gas Company

		Data Source
20 - Year U. S. Treasury Bond Yield	4.48%	1
Long - Horizon Expected Equity Risk Premium for Micro-Cap Companies (category 10x)	9.69%	2

Risk Premium Calculation

ROE = 0.0448 + 0.0969 = 14.17%

Data Sources:

1. Yield for 20-Year Treasury Constant Maturity Rate, Feb 1, 2010
   Federal Reserve Bank of St. Louis Economic Research

2. Ibbotson 2010 SBBI Valuation Yearbook, Morningstar, Inc., 2010, p. 92

Exhibit MJB - 20
Return on Equity for Companies of Comparable Risk
As Measured by a Beta Value of 0.65

Company Name	Ticker Symbol	Industry	Beta	Return on Common Equity
Abatix Corp	ABIX	MACHINE	0.65	10.3%
Abigail Adams Natl Bncrp	AANB	BANK	0.65	9.7%
Abington Bancorp Inc	ABBC	THRIFT	0.65	0.9%
Aldila Inc.	ALDA	RECREATE	0.65	-9.5%
All-American Sportpark Inc	AASP	RECREATE	0.65	-1.0%
Amer. Pacific	APFC	CHEMSPEC	0.65	-8.4%
American Community Newspapers	ACNIQ	NWSPAPER	0.65	-7.5%
American Medical Alert	AMAC	ELECTRNX	0.65	7.9%
American Wagering Inc	BETM	HOTELGAM	0.65	239.9%
AmeriServ Finl Inc	ASRV	BANK	0.65	6.0%
Ameritrans Cap Corp	AMTC	FINSERV	0.65	-44.3%
Amgen	AMGN	BIOTECH	0.65	20.6%
Andrew Peller Ltd 'A'	ADW/A.TO	BEVERAGE	0.65	9.7%
Aqua America	WTR	WATER	0.65	9.3%
Arc Wireless Solutions Inc	ARCW	WIRELESS	0.65	-12.9%
Arch Cap Group Ltd	ACGL	INSPRPTY	0.65	8.5%
Arden Group 'A'	ARDNA	GROCERY	0.65	48.2%
Argo Group International	AGII	INSPRPTY	0.65	4.6%
Aspyra Inc	APYI	SOFTWARE	0.65	-76.4%
AssuranceAmerica Corporation	ASAM	INSPRPTY	0.65	-26.8%
Assured Pharmacy Inc	APHY	B2B	0.65	81.5%
Astral Media Inc. 'A'	ACM/A.TO	ENTRTAIN	0.65	20.7%
Astro-Med	ALOT	COMPUTER	0.65	5.8%
Astrotech Corp	ASTC	DEFENSE	0.65	10.0%
ATCO Ltd.	ACO/X.TO	GASDIVRS	0.65	15.3%
Atlantic So. Financial Grp Inc	ASFN	BANK	0.65	-0.7%
Atmos Energy	ATO	GASDISTR	0.65	8.3%
Aware Inc Mass	AWRE	SOFTWARE	0.65	-6.3%
BackWeb Technologies Ltd	BWEBF	INTERNET	0.65	-96.7%
Bank of Marin Bancorp	BMRC	BANK	0.65	12.2%
Bank South Carolina	BKSC	BANK	0.65	11.0%
Bar Harbor Bankshares	BHB	BANK	0.65	11.8%
Bay Banks of Virginia Inc	BAYK	BANK	0.65	5.9%
Bennet Environmental Inc	BEVFF	ENVIRONM	0.65	-35.8%
Bingo.com Ltd.	BNGOF	INTERNET	0.65	-75.4%
Bodisen Biotech Inc	BBCZ	CHEMSPEC	0.65	-16.6%
British Amer Tobacco ADR	BTI	TOBACCO	0.65	48.7%
Brooklyn Federal Bancorp	BFSB	THRIFT	0.65	5.7%
Bryn Mawr Bank Corp.	BMTC	BANK	0.65	10.1%
Capitol Fed. Fin'l	CFFN	THRIFT	0.65	5.8%
CardioGenesis Corp	CGCP	MEDSUPPL	0.65	-7.6%
Carriage Services Inc	CSV	INDUSRV	0.65	3.8%

Exhibit MJB - 20
Return on Equity for Companies of Comparable Risk
As Measured by a Beta Value of 0.65

Company Name	Ticker Symbol	Industry	Beta	Return on Common Equity
Cass Information Sys Inc	CASS	FINSERV	0.65	17.9%
Cellcom Israel Ltd	CEL	TELESERV	0.65	288.0%
Central VA Bankshares	CVBK	BANK	0.65	-47.4%
CH Energy Group	CHG	UTILEAST	0.65	8.1%
Chattem Inc.	CHTT	COSMETIC	0.65	30.5%
CHDT Corp	CHDO	DIVERSIF	0.65	-96.1%
Cleco Corp.	CNL	UTILCENT	0.65	9.6%
CNB Finl Corp	CCNE	BANK	0.65	8.4%
Columbia Commercial Bancorp	CLBC	BANK	0.65	5.6%
Comarco Inc.	CMRO	WIRELESS	0.65	-58.4%
Commonwealth Bankshares Inc	CWBS	BANK	0.65	-3.5%
Community Shores Bank Corporat	CSHB	BANK	0.65	-6.9%
Comprehensive Care Corp.	CHCR	MEDSERV	0.65	71.8%
Computer Modelling Grp. Inc.	CMG.TO	SOFTWARE	0.65	60.1%
Comtech Telecom.	CMTL	TELEQUIP	0.65	7.9%
ConAgra Foods	CAG	FOODPROC	0.65	14.7%
Conrad Inds Inc	CNRD	INDUSRV	0.65	40.3%
Consol. Edison	ED	UTILEAST	0.65	9.5%
Corby Distilleries LTD	CDLB.TO	BEVERAGE	0.65	12.8%
Cordia Corp	CORG	SOFTWARE	0.65	96.1%
Craft Brewers Alliance	HOOK	BEVERAGE	0.65	-3.4%
Crown Crafts Inc.	CRWS	FURNITUR	0.65	-9.7%
Cuisine Solutions Inc.	CUSI	FOODPROC	0.65	0.2%
Datawatch Corp	DWCH	SOFTWARE	0.65	-95.6%
DaVita Inc.	DVA	MEDSERV	0.65	19.2%
Dean Foods	DF	FOODPROC	0.65	33.1%
Delta Natural Gas	DGAS	GASDIVRS	0.65	8.8%
Diamond Foods	DMND	FOODPROC	0.65	13.8%
Direct Insite Corp	DIRI	SOFTWARE	0.65	76.3%
Diversinet Corp.	DVNTF	ELECTRNX	0.65	-21.5%
Drinks Americas Holdings Ltd	DKAM	BEVERAGE	0.65	37.5%
Duke Energy	DUK	UTILEAST	0.65	6.1%
eGain Communications Corp	EGAN	INTERNET	0.65	-53.3%
Elecsys Corp	ESYS	DEFENSE	0.65	7.6%
Electro-Sensors	ELSE	ELECEQ	0.65	6.5%
Emergency Medical Services	EMS	MEDSERV	0.65	15.7%
Enbridge Inc.	ENB.TO	OILGAS	0.65	11.8%
Endo Pharmac. Hldgs.	ENDP	DRUG	0.65	23.2%
Epolin Inc /NJ/	EPLN	CHEMSPEC	0.65	9.2%
Equitable Financial Corp	EQFC	THRIFT	0.65	-0.8%
ESSA Bancorp Inc	ESSA	THRIFT	0.65	3.5%
Eurobancshares Inc.	EUBK	BANK	0.65	-8.2%

Exhibit MJB - 20

Return on Equity for Companies of Comparable Risk
As Measured by a Beta Value of 0.65

Company Name	Ticker Symbol	Industry	Beta	Return on Common Equity
Exponent Inc	EXPO	INDUSRV	0.65	18.1%
Express-1 Expedited Solutions	XPO	AIRTRANS	0.65	10.6%
Ezenia! Inc	EZEN	INTERNET	0.65	-56.6%
FinancialContent Inc	FCON	FINSERV	0.65	71.2%
First Business Fin'l Svcs	FBIZ	BANK	0.65	5.9%
Flexible Solutions Intl Inc	FSI	CHEMSPEC	0.65	3.8%
Fresenius Medical Care	FMS	MEDSERV	0.65	13.7%
Frisch's Restaurants	FRS	RESTRNT	0.65	9.4%
FullCircle Registry Inc.	FLCR	INDUSRV	0.65	99.3%
Gallery Of History Inc.	HIST	RETAILSP	0.65	-18.9%
Genzyme Corp.	GENZ	DRUG	0.65	5.8%
Gilead Sciences	GILD	DRUG	0.65	48.4%
Global Environmental Energy C	GEECF	MEDSUPPL	0.65	23.7%
Global Med Tech	GLOB	MEDSERV	0.65	78.0%
GlobalOptions Group Inc	GLOI	INDUSRV	0.65	-16.5%
Green Builders Inc	GRBU	PROPMGMT	0.65	61.2%
Green St Energy Inc	GSTY	ELECTRNX	0.65	25.4%
Habersham Bancorp Inc	HABC	BANK	0.65	-38.1%
Hallador Petroleum Company	HPCO	OILPROD	0.65	13.5%
Hershey Co.	HSY	FOODPROC	0.65	135.3%
HMS Holdings Corporation	HMSY	HLTHSYS	0.65	12.0%
Hollywood Media Corp	HOLL	ENTRTAIN	0.65	-18.7%
HomeFed Corporation	HOFD	REIT	0.65	-4.9%
Hormel Foods	HRL	FOODPROC	0.65	14.2%
Hudson Holding Corporation	HDHL	MEDSERV	0.65	-26.5%
Hudson Technologies Inc.	HDSN	ENVIRONM	0.65	52.5%
ICU Medical	ICUI	MEDSUPPL	0.65	9.6%
Ikonics Corp	IKNX	CHEMSPEC	0.65	7.0%
Indiana Community Bancorp	INCB	THRIFT	0.65	9.0%
Innovative Software Techs Inc	INIV	B2B	0.65	39.3%
IntegraMed Amer Inc	INMD	MEDSERV	0.65	6.9%
Intermountain Community Bncp	IMCB	BANK	0.65	1.5%
Iris International Inc	IRIS	MEDSUPPL	0.65	11.9%
Jacada Ltd.	JCDA	SOFTWARE	0.65	-8.6%
Jewett-Cameron Trading Co. Ltd	JCTCF	HOUSEPRD	0.65	8.5%
K12 Inc	LRN	EDUC	0.65	6.8%
Katy Industries Inc	KATY	DIVERSIF	0.65	18.1%
K-Fed Bancorp	KFED	THRIFT	0.65	5.3%
Kolorfusion Intl Inc	KOLR	MACHINE	0.65	72.4%
Kraft Foods	KFT	FOODPROC	0.65	12.8%
Laboratory Corp.	LH	MEDSERV	0.65	30.4%
LaPolla Industries Inc	LPAD	CHEMSPEC	0.65	73.7%

Exhibit MJB - 20
Return on Equity for Companies of Comparable Risk
As Measured by a Beta Value of 0.65

Company Name	Ticker Symbol	Industry	Beta	Return on Common Equity
Lincare Holdings	LNCR	MEDSERV	0.65	24.5%
LNB Bancorp Inc	LNBB	BANK	0.65	4.2%
Lyris Inc	LYRI	B2B	0.65	-71.5%
Manfelder Metals Ltd	MNSF	FINSERV	0.65	-27.1%
Market Leader Inc	LEDR	PROPMGMT	0.65	-21.0%
McDonald's Corp.	MCD	RESTRNT	0.65	31.4%
Mendocino Brewing Inc	MENB	BEVERAGE	0.65	-9.4%
MER Telemgmt	MTSL	TELEQUIP	0.65	-32.1%
Merisel Inc.	MSEL	RETAILSP	0.65	-10.3%
MGE Energy	MGEE	UTILCENT	0.65	11.0%
Milestone Scientific	MLSS	MEDSUPPL	0.65	-84.8%
Motorcar Parts Of America Inc.	MPAA	AUTO	0.65	5.7%
MutualFirst Financial Inc	MFSF	THRIFT	0.65	4.9%
National Research Corp	NRCI	HLTHSYS	0.65	19.3%
National Technical Systems	NTSC	INDUSRV	0.65	6.9%
Nat'l Bank of Canada	NA.TO	BANKCAN	0.65	14.8%
Natl RV Holdings	NRVHQ	HOMESRVS	0.65	-67.4%
Navigators Group	NAVG	FINSERV	0.65	7.5%
Neoprobe Corp.	NEOP	MEDSUPPL	0.65	170.7%
New Jersey Resources	NJR	GASDISTR	0.65	14.6%
Nexgen Biofuels Ltd	NXGNF	MEDSUPPL	0.65	194.0%
North American Gaming and Ente	NAGM	HOTELGAM	0.65	-10.3%
North American Tech Group	NAMC	INDUSRV	0.65	4.1%
Northern Technologies Intl	NTIC	PACKAGE	0.65	-13.1%
Northrim BanCorp Inc.	NRIM	BANK	0.65	5.8%
NSTAR	NST	UTILEAST	0.65	13.0%
OCTuS Inc	OCTI	SOFTWARE	0.65	12.9%
Onstream Media Corporation	ONSM	ADVERT	0.65	-62.3%
Orbit/FR Inc	ORFR	INSTRMNT	0.65	-51.8%
Payment Data Systems Inc	PYDS	INTERNET	0.65	256.8%
People's United Fin'l	PBCT	THRIFT	0.65	2.7%
Performance Tech Inc	PTIX	TELESERV	0.65	3.7%
PharMerica Corp.	PMC	DRUGSTOR	0.65	8.9%
Piedmont Natural Gas	PNY	GASDISTR	0.65	13.2%
PowerVerde Inc	PWVI	POWER	0.65	252.3%
QuadraMed Corp	QDHC	HLTHSYS	0.65	46.4%
Quest Diagnostics	DGX	MEDSERV	0.65	17.8%
Questar Assessment Inc	QUSA	EDUC	0.65	1.8%
Renhuang Pharmaceutical Inc	RHGP	DRUGSTOR	0.65	29.4%
Rosetta Genomics Ltd.	ROSG	DRUG	0.65	-58.8%
Samuel Manu-Tech Inc.	SMT.TO	STEEL	0.65	8.5%
Sand Technology Inc	SNDTF	SOFTWARE	0.65	50.2%

Exhibit MJB - 20
Return on Equity for Companies of Comparable Risk
As Measured by a Beta Value of 0.65

Company Name	Ticker Symbol	Industry	Beta	Return on Common Equity
SCANA Corp.	SCG	UTILEAST	0.65	11.4%
Seanergy Maritime Corp	SHIP	FINSERV	0.65	-20.9%
Selectica Inc	SLTC	INTERNET	0.65	-44.8%
SensiVida Medical Technologie	SVMT	MEDSUPPL	0.65	39.3%
Simulations Plus Inc	SLP	HLTHSYS	0.65	13.3%
Sparton Corp.	SPA	ELECTRNX	0.65	-20.4%
Specialty Underwriters Allnce	SUAI	INSPRPTY	0.65	7.4%
Spectra Energy Partners LP	SEP	OILFIELD	0.65	8.9%
Synthetech Inc.	NZYM	DRUG	0.65	12.0%
Tapestry Pharmaceuticals Inc	TPPHQ	DRUG	0.65	-75.7%
Tel-Instrument Electronics	TIK	INSTRMNT	0.65	2.8%
The Walking Co Holdings Inc	WALK	RETAILSP	0.65	-7.5%
Tidelands Bancshares Inc	TDBK	BANK	0.65	1.0%
Timberland Bancorp Inc	TSBK	THRIFT	0.65	10.3%
Todd Shipyards	TOD	MARITIME	0.65	7.4%
TOR Minerals International	TORMD	CHEMSPEC	0.65	-20.3%
Tyler Technologies Corp.	TYL	DIVERSIF	0.65	18.2%
U.S. Basketball League Inc	USBL	ENTRTAIN	0.65	14.1%
UGI Corp.	UGI	GASDISTR	0.65	16.2%
UMH Properties Inc.	UMH	HOMEBILD	0.65	3.4%
Vasamed Inc	VSMD	MEDSUPPL	0.65	24.6%
Vector Group Ltd.	VGR	TOBACCO	0.65	180.0%
Vertical Branding inc	VBDG	ADVERT	0.65	-81.0%
Voyager Learning Company	VLCY	INFOSER	0.65	-32.8%
Weis Markets	WMK	GROCERY	0.65	7.1%
Westfield Financial Inc	WFD	THRIFT	0.65	2.6%
WGL Holdings Inc.	WGL	GASDISTR	0.65	11.6%
Wisconsin Energy	WEC	UTILCENT	0.65	10.7%
Xcel Energy Inc.	XEL	UTILWEST	0.65	9.2%
Xfone Inc.	XFN	TELESERV	0.65	5.2%
XFormity Technologies Inc	XFMY	INTERNET	0.65	-1.3%
York Water Co	YORW	WATER	0.65	9.2%
Zunicom Inc	ZNCM	TELEQUIP	0.65	-2.3%
Average				12.0%

Source: Value Line Investment Analyzer, Screen on Beta of 0.65

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF RATES	)))	CASE NO. 2010-00116

DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

AFFIDAVIT

The affiant, William Steven Seelye, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2010-00116 in the Matter of: Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional examination as may be appropriate at the hearing in Case No. 2010-00116 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

W. Steven Seelye

WILLIAM STEVEN SEELYE

STATE OF KENTUCKY)
)
COUNTY OF ~~CLARK~~ Oldham)

Subscribed and sworn to before me by William Steven Seelye, this the 21st day of April, 2010.

My Commission Expires: 4-25-2013

Christie K McCormick

Notary Public, State at Large, Kentucky

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor Delta Natural Gas Company Inc.'s ("Delta's") proposed rates for natural gas service; to describe the proposed allocation of the revenue increase; to sponsor the fully allocated class cost of service study based on Delta's embedded costs for the 12 months ended December 31, 2009; to sponsor the temperature normalization adjustment; and to sponsor Delta's depreciation study supporting the proposed depreciation rates and the pro-forma adjustment to depreciation expenses.

Q. Please summarize your testimony.

A. Delta is proposing to increase base rate revenues by $5,315,428. The Company has a large residential customer base, and, as a result, Delta is proposing to allocate $3,541,111 or 67% of the increase to the residential class. The Company is proposing to collect these revenues in large part by increasing the residential customer charge. By recovering the residential increase largely through the customer charge, Delta is proposing to continue the movement undertaken in previous rate cases in the direction of a "Straight Fixed Variable" rate design, which is a methodology that has been adopted in other regulatory jurisdictions. More specifically, Delta is proposing to recover through the monthly customer charge most of the customer-related costs identified in the cost of service study. The Prime Group prepared a fully allocated, embedded cost of service study for Delta's test-year operations using a cost of service methodology that has been accepted by the Commission in previous rate cases. The purpose of the cost of service study is to determine the contribution that each customer class is making towards Delta's overall rate of return. Rates of return are computed for each rate class. Delta was guided by the embedded cost of service study in allocating the proposed revenue increase to the classes of service. Delta is also proposing to make a temperature normalization adjustment to sales and transportation volumes not covered by the Company's Weather Normalization Adjustment ("WNA") clause. In addition, Delta is proposing to change a number of its depreciation rates based on the depreciation study included as an exhibit to my testimony.

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Qualifications, (II) Rate Design and the Allocation of the Increase, (III) Gas Cost of Service Study, (IV) Temperature Normalization Adjustment, (V) Revenue Adjustment to Reflect Year-End Customers, and (VI) Depreciation Study and Depreciation Expense Adjustment.

Q. Are you sponsoring any Exhibits to your testimony?

A. Yes. The exhibits that accompany my testimony in this proceeding are listed below.

Seelye Exhibit 1	Summary of Qualifications
Seelye Exhibit 2	Reconstruction of Billing Determinants
Seelye Exhibit 3	Summary of Proposed Increase
Seelye Exhibit 4	Calculated Billings at Proposed Rates

Seelye Exhibit 5	Cost of Service Study: Functional Assignment & Classification
Seelye Exhibit 6	Class Cost of Service Study: Allocation of Costs by Rate Class
Seelye Exhibit 7	Class Cost of Service Study: Storage Allocation Factor
Seelye Exhibit 8	Class Cost of Service Study: Zero Intercept Analysis
Seelye Exhibit 9	Temperature Normalization Adjustment
Seelye Exhibit 10	Year-End Customer Adjustment - Not Proposed
Seelye Exhibit 11	Depreciation Study

I. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E.

Since leaving LG&E, I have performed cost of service and rate studies for over 150 investor-owned utilities, rural electric cooperatives, and municipal utilities. I have also developed or modified fuel and purchased power adjustment mechanisms for numerous electric and gas utilities, including integrated investor-owned utilities, integrated municipal utilities and distribution cooperatives. A more detailed description of my qualifications is included in Seelye Exhibit 1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes, on many occasions. I have testified in over 50 regulatory proceedings in 11 different jurisdictions. A listing of my testimony is included in Seelye Exhibit 1.

II. RATE DESIGN AND THE ALLOCATION OF THE INCREASE

Q. Is Delta proposing to change the relationship between the customer charge and volumetric charge for the residential rate class?

A. Yes. The Company is proposing a significant increase in its customer charge. Delta has a traditional residential base rate design consisting of a customer charge and a volumetric charge. This type of rate design is referred to as a "two-part" rate. Under this design, a portion of Delta's non-gas costs are collected through a monthly fixed customer charge, which does not vary with usage, and a portion of the costs are collected via a volumetric charge applied to each unit of natural gas used. Delta's residential customer charge is currently $15.30 per month (not including the $0.20 per month collected under Delta's Energy Assistance Program Tariff Rider) and the non-gas volumetric charge is $0.41580 per Ccf (or $4.1580 per Mcf). Gas costs are recovered through the Gas Cost Recovery Rate (GCR), which is a volumetric charge.

Some regulatory jurisdictions have shifted from a traditional two-part rate design to a design in which *all* non-gas costs are recovered through a fixed monthly customer charge. This type of rate structure is referred to as a "Straight Fixed Variable" rate design. This rate design evolved from pipeline rate designs that recovered all fixed costs through a fixed charge and all variable costs through a volumetric charge. Because non-gas costs are *fixed* for a gas distributor, and do not vary with the amount of gas purchased by its customers, all non-gas costs are recovered through a *fixed* monthly customer charge under a Straight Fixed Variable rate structure.

Q. Please describe the Straight Fixed Variable rate design further.

A. Under a Straight Fixed Variable rate design, a gas utility eliminates in its entirety the distribution cost component of the volumetric rate, and increases the fixed monthly customer charge accordingly. By recovering its fixed distribution costs fully through a fixed monthly charge, a utility severs the relationship between its natural gas delivery revenue (revenue less the cost of gas) and its sales of natural gas. This insulates a utility's income from changes in sales per customer.

Utilities implement a Straight Fixed Variable rate design for several reasons. Some of the more prevalent reasons to adopt Straight Fixed Variable rates are:

- A Straight Fixed Variable rate design is a simple form of decoupling, which many environmental and conservation advocates consider to be a cornerstone to the implementation of comprehensive energy conservation programs.
- A Straight Fixed Variable rate design removes all incentives for the Company to encourage customers to use more natural gas.
- A Straight Fixed Variable rate design reflects the cost of providing natural gas delivery service and sends the appropriate price signal to customers.
- Because low-income customers typically use more gas than the average customer, a Straight Fixed Variable rate design will remove the subsidy that low-income customers are providing to other residential customers.

- Through the implementation of a Straight Fixed Variable rate design, the volatility of customers' bills will be reduced.
- A Straight Fixed Variable rate design is easy for customers to understand.
- Adopting a Straight Fixed Variable rate design typically enhance the viability of gas distribution operations as a business.
- Straight Fixed Variable rate designs have been implemented in a number of progressive regulatory jurisdictions and are being considered in many others.
- A Straight Fixed Variable rate design is consistent with emerging national energy policy.

Q. Has a Straight Fixed Variable rate design been adopted in other jurisdictions?

A. Yes. The Missouri Public Service Commission ("Missouri Commission") adopted a Straight Fixed Variable rate design for Atmos Energy Corporation (*Case No. GR-2006-0387*, Order dated February 22, 2007) and Missouri Gas Energy, a division of Southern Union Company (*Case No. GR-2006-0422*, Order dated March 22, 2007). The Straight Fixed Variable rate design was proposed by the Missouri Commission Staff in the Atmos proceeding. A Straight Fixed Variable rate design is also used by the Atlanta Gas Light Company in Georgia.

In the Atmos Proceeding, the Missouri Commission accepted the Staff's recommendation to eliminate the traditional two-part rate structure and to adopt instead a Straight Fixed Variable design because collecting fixed costs through a volumetric charge:

a) Creates unnecessary volatility in customer bills by collecting too much cost in the winter months;

b) Sends incorrect price signals to residential customers;

c) Forces residential customers whose usage is greater than the average to pay more than the cost of service, while allowing smaller customers to pay less than the cost of service;

d) Provides no incentive for the utilities to promote conservation.

(*Atmos Energy Corporation, Case No. GR-2006-0387*, Order dated February 22, 2007, pp. 19-20.)

More recently, the Public Utilities Commission of Ohio ("Ohio Commission") authorized Vectren Energy Delivery of Ohio to transition to a Straight Fixed Variable rate design over a 12-month period. (*Vectren Energy Delivery of Ohio, Case No. 07-1080-GA-AIR; Case No. 07-1081-GA-ALT; Case No. 08-632-GA-AAM*, Order dated January 7, 2009.) In that proceeding the Ohio Commission Staff argued that Straight Fixed Variable rates are "reasonable, understandable, and send the proper price signals to customers." (*Id.*, at 22.) The Ohio Commission found that a Straight Fixed Variable rate design "promotes the regulatory principles of providing a more equitable allocation among customers, regardless of usage. It fairly apportions the fixed costs of service among all customers so that everyone pays their fair share." (*Id.*, at 30.) The Ohio Commission also concluded that a Straight Fixed Variable rate design sends a better price signal, stating as follows:

> [T]he Commission believes that a levelized rate design sends better price signals to consumers. The possible response of consumers to an increase in the customer charge, i.e., dropping gas service entirely and switching to a different fuel, is much less likely to occur than consumers changing their level of gas usage in response to a change in the volumetric rates. When a utility is entitled to recover costs in excess of its costs for providing the next increment of gas service, a more economically efficient rate design is

> one that recovers these additional costs largely through a change that has little impact on consumer behavior.
>
> Customers will not be misled into believing that reductions in consumption will allow them to avoid the fixed costs of the distribution system, as feared by Staff. However, the commodity costs comprise 75 to 80 percent of the total bill. (TR. III at 68). Therefore, we believe that the gas usage will still have the biggest influence on the price signals received by customers when making gas consumption decisions and that customers will still receive the appropriate benefits of any conservation efforts. (*Id.*, at 25-26.)

In Kentucky, Straight Fixed Variable rates have also been proposed by Duke Energy Kentucky, Inc. (Case No. 2009-00202) and by Columbia Gas of Kentucky, Inc. (Case No. 2009-00141). While both of those cases settled without Straight Fixed Variable rate designs, the parties agreed to, and the Commission approved, significant increases in their residential customer charges. Additionally, LG&E recently proposed Straight Fixed Variable rates in Case No. 2009-00549, a proceeding that is open before the Commission at this time.

Q. Are there any reasons for gas utilities not to adopt Straight Fixed Variable rate design?

A. Yes. While the reasons listed above for adopting Straight Fixed Variable rates are sound, utilities may elect not to adopt Straight Fixed Variable rates in order to avoid rate shock. Instead, they may adopt an incremental approach over several rate cases with movement in the direction of increasing fixed charges to appropriately reflect fixed costs. This is consistent with accepted ratemaking practices and with the principle of gradualism.

Q. Is Delta proposing a Straight Fixed Variable rate design?

A. No. Although Delta is not recommending a Straight Fixed Variable rate design, the Company is proposing to continue the significant movement in that direction undertaken in its last rate case. Specifically, Delta is proposing to set the volumetric charge close to the current level and recover nearly all of the residential revenue increase in the customer charge. Under a Straight Fixed Variable design the non-gas volumetric charge would be eliminated and all of Delta's non-gas costs would be recovered through the monthly customer charge.

Although Delta's proposed residential rate will fall far short of recovering all fixed costs in the customer charge, it will come reasonably close to recovering the customer-related costs identified in the fully allocated class cost of service study submitted in this proceeding. In the cost of service study, Delta's non-gas fixed costs are classified as either customer-related or demand-related. With a Straight Fixed Variable rate design adopted in Missouri, Georgia, and Ohio, all of these costs – both customer-related and demand-related fixed costs – would be recovered through the monthly customer charge. In this proceeding Delta is proposing to recover most – but not all – of its customer-related costs through the monthly customer charge. Delta's customer-related cost for residential customers is currently $27.72 per month. However, the Company is only charging $15.30 per month, or 55% of the customer-related costs that were identified in the cost of service study. In this proceeding, Delta is proposing to increase the monthly customer charge to $24.00, which represents 87% of the customer-related costs identified in the cost of service study. Although this increase in the customer charge is less than it would be with Straight Fixed Variable rate design, Delta's proposal is a significant shift in that direction.

Q. What would the proposed customer charge be if a Straight Fixed Variable rate design were adopted?

A. Under a Straight Fixed Variable rate design, the fixed monthly customer charge for the residential class would be $43.77.

Q. What are the benefits of recovering most of the customer-related costs through the customer charge?

A. Recovering more of Delta's customer-related costs through the fixed monthly customer charge will better reflect the actual cost of service through rates and will thus send a more accurate price signal to customers. In addition, Delta's proposed customer charge will reduce the volatility in customer bills by lowering the amount charged during the winter.

The Company's proposal will also eliminate rate subsidies within the residential customer class. Currently, customers with lower than average usage are being subsidized by customers with higher than average usage. Based on data that I have seen from other gas utilities, including a gas utility in the region, low income customers – contrary to a common misconception – tend to purchase more gas than the average customer. One likely reason for this is that low income customers often have poorly insulated homes, which causes their gas usage to be higher than the average even though their homes may have less square footage than the average. When customer-related costs are recovered through the volumetric charge, low income customers who use more than the average will subsidize customers who use less natural gas than the average.

Yet another advantage of Delta's proposal – and one which should be an important consideration for the Company – is that a higher customer charge should help mitigate the erosion in margins that Delta has been experiencing for a number of years. Delta's average Mcf per customer has been trending down for many years now. Since 2000, the average residential usage has gone from 75 Mcf per customer in 2002 to 55 Mcf in 2009. This decline in average consumption will continue to exacerbate the earnings erosion as long as customer-related costs are included in the volumetric charge.

Because a large percentage of Delta's fixed costs have been recovered through a volumetric charge, the decline in customer usage has the effect of reducing the recovery of fixed costs and eroding the Company's earnings. Delta has not had an opportunity to earn the rate of return on equity authorized by the Commission in Delta's last three rate cases, and decreasing sales volumes have contributed heavily to this trend. This is discussed in detail in the testimony of Dr. Blake. Recovering more fixed costs through the customer charge should help mitigate this erosion in earnings.

Q. Will the proposed rate design better position the Company to encourage conservation on the part of customers?

A. Yes. Recovering a significant portion of fixed costs through a volumetric charge works to penalize the Company when customers conserve. Essentially all of Delta's non-gas costs are fixed and do not vary as customer volumes go up or down. With a significant portion of fixed costs recovered through volumetric charges, the Company's financial results are adversely affected from consumer conservation. Because Delta is not proposing to eliminate the volumetric charge for non-gas costs through the adoption a Straight Fixed Variable rate design, the Company's non-gas related revenues will continue to decline as a result of conservation, but not nearly as much as they would if Delta had proposed an increase in the volumetric charge. Thus increasing the customer charge will help maintain Delta's financial integrity while encouraging customers to use less natural gas.

Q. Have you prepared an exhibit reconstructing Delta's test-year billing units?

A. Yes. In order to develop Delta's proposed rates it was necessary to reconstruct test-year billing units. The reconstruction of Delta's billing determinants is shown on Seelye Exhibit 2.

Q. After considering all of the required adjustments, what is the proposed increase in revenues and how is the increase apportioned to the individual customer classes?

A. Delta is proposing to increase its annual revenues by $5,315,428. As shown on Seelye Exhibit 3, this amount would result in an increase of 11.54% in total operating revenue.

Delta is not proposing to increase the collection charge, reconnection charge, or bad check charge, so there is no proposed increase in miscellaneous revenue.

The proposed rates apportion the revenue increase among the customer classes as follows:

TABLE 1
Proposed Gas Increase

Customer Class	Proposed Increase	Percentage Increase
Residential	$ 3,538,987	15.85%
Small Non-Residential	593,145	9.17%
Large Non-Residential	668,559	7.27%
Unmetered Gas Lights	448	4.31%
On-System Transportation	261,259	6.31%
Off-System Transportation	253,030	7.41%
Total Sales and Transportation	$ 5,315,428	11.54%

As shown on Seelye Exhibit 4, the effects on individual class revenues were determined by applying both the current and proposed charges to the adjusted billing determinants for each customer class.

Q. What was the basic underlying information that supported the proposed allocation among rate classes?

A. The cost of service study provided information measuring the extent to which the revenues generated by each customer class contribute to the overall return earned by the Company. The cost of service study indicates that the individual class rates of return ranged between 3.44%

and 15.08% as compared to an overall adjusted actual return on rate base of 4.79%, with residential being the lowest (excluding special contracts). This indicates a need to increase the revenues collected from the residential class more than the other classes. The rates of return for all of the rate classes except the special contracts were measurably higher than for residential. The cost of service study also showed that the earned return for the interruptible rates were extremely high when compared to the other classes of service. This is also true, albeit to a lesser degree, for the off-system transportation rate.

Because the rate of return for the residential class is significantly below Delta's proposed overall rate of return of 8.66%, Delta is proposing to increase the residential rate by a larger percentage than the other classes in order to bring the residential rate of return more in line with the overall rate of return. The proposed rate of return for the residential rate is 8.19%.

The special contracts are served under fixed-price arrangements; therefore, none of the revenue increase will be allocated to these customers.

Delta does not propose to increase the rates for the interruptible rate class because of the high rates of return for this rate class. With a rate of return of 15.08% for interruptible service, a rate increase for this rate class cannot be justified.

Delta is proposing increases for the small and large non-residential rate classes that will result in rates of return of 9.21% and 10.64 %, respectively, based on the results of the cost of service study. The Company is also proposing an increase in the off-system transportation rate that will produce a rate of return of approximately 7.26%.

Q. Is it important to consider competitive issues when designing rates?

A. Yes. It is extremely important to take into consideration the competitive pressures facing the utility when designing rates. Utility customers have many more options than they did in the past, and they are also becoming more sophisticated in how to utilize the various competitive products that are now available to them. However, the natural gas industry has always experienced keen competition from alternative fuels. When customers have alternatives (and the ability to substitute fuel oil for natural gas is only one example), gas distribution companies must be able to ensure that the revenues contributed by these customers are retained as long as they make some contribution to the utility's fixed costs. Industrial and commercial customers generally have more options than residential customers. Therefore, it is important not to charge rates to commercial and industrial customers that are not competitive and/or exceed the cost of providing service. Otherwise, large commercial and industrial customers will leave the system, forcing residential and small commercial customers, who have fewer options, to pay for fixed costs that are left stranded by the departing customers. Unlike volumetric costs, such as the cost of the gas commodity that a distribution company buys for its customers, a utility's fixed costs generally do not disappear if it sells less gas, but instead are spread over a lower volume of gas, thus causing the utility's rates to increase. Therefore, if a utility loses several large high-load factor industrial customers, then the utility's fixed costs do not suddenly disappear but are shifted to the remaining customers in future rate proceedings. On the other hand, if the utility can attract high-load factor customers or, even better, customers with off-peak usage, then the utility's fixed costs can be spread over a larger volume of gas, thus causing gas rates to go down, benefiting all customers.

Q. Are the competitive issues outlined above especially relevant to Delta?

A. Yes, for two reasons. First, Delta serves a customer base that is both rural and residential. This means that overall consumption and customer count are both lower than they would otherwise be if the utility served a more urban or industrial service territory -- which means costs are spread across comparatively fewer users with less consumption. Second, the electric provider in Delta's service territory is Kentucky Utilities Company, which has electric rates that are among the lowest in the region. This affords customers a viable, attractive, economic option for meeting their energy needs with electricity rather than natural gas. These specific circumstances for Delta only serve to augment the reasons why it is important for Delta to keep the rates as competitive as possible while considering the cost of serving these customers.

Q. What were the ratemaking objectives in developing the proposed gas rates?

A. As explained earlier, the broad aim in rate design is to develop rates that more closely reflect the cost of providing service. Therefore, one of the key objectives was to bring the unit charges more in line with the unit costs derived from the cost of service study. Thus, the proposed rates move the charges toward the unit costs indicated by the cost of service study.

Q. Have you analyzed the customer-related costs for Delta's rate classes?

A. Yes. Page 20 of Seelye Exhibit 6 shows the unit customer-related costs for each rate class based on the results of the cost of service study. The customer-related cost for each rate class was derived by calculating the customer-related cost of service, or "revenue requirement," and dividing this amount by the number of customers. Delta's cost of service includes (1) return on investment, (2) income taxes, (3) operation and maintenance expenses, (4) depreciation expenses, and (5) other taxes. The proposed overall rate of return of 8.66% was used to calculate the unit cost.

Q. What are the proposed unit charges for the residential rate class?

A. Delta is proposing a customer charge of $24.00 per customer per month and a flat commodity charge of $0.43344 for all Ccf. The current rate consists of a customer charge of $15.30 and commodity charge of $0.41580 per Ccf.

Q. What are the proposed unit charges for the small non-residential rate class?

A. Delta is proposing a customer charge of $35.00 per customer per month and a flat commodity charge of $0.43344 for all Ccf. The current rate consists of a customer charge of $25.00 and commodity charge of $0.41580 per Ccf.

Q. What are the proposed unit charges for the large non-residential rate class?

A. Delta is proposing a customer charge of $150.00 per customer per month and a commodity charge of $0.43344 for the first 2,000 Ccf, $0.26855 for the next 8,000 Ccf, $0.18894 for the next 40,000 Ccf, $0.14894 for the next 50,000 Ccf, and $0.12984 for all usage over 100,000 Ccf. The first block was set at the same level as the first block in the small non-residential rate, and the current charge differentials between the blocks were maintained.

Q. Is Delta proposing to modify the interruptible schedules?

A. No. As indicated earlier, rate increases for these services cannot be justified in light of the high class rates of return.

Q. Is Delta proposing to modify the unmetered gas lights schedules?

A. Yes. Relatively small increases are proposed for the residential, commercial, and small commercial unmetered lights schedules, which collectively amount to a 4.3% increase over current rates.

Q. Is Delta proposing to modify the on-system transportation rates?

A. Yes. Delta's on-system transportation rates are net margin rates, wherein the on-system transportation rates have the same distribution delivery charges as the corresponding sales rates; therefore, the Company is proposing the same increase in net margins for its on-system transportation rates as for the underlying sales rates. Collectively, this amounts to a 6.3% increase over current rates.

Q. Is Delta proposing to increase the off-system transportation rate?

A. Yes. Delta is proposing to increase the off-system transportation rate from $0.27 to $0.29 per Mcf of gas transported, or in the case of measurement based on heating value, $0.29 per dekatherm.

III. GAS COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for Delta's natural gas operations based on financial and operating results for the 12 months ended December 31, 2009?

A. Yes. I supervised and participated in the preparation of a fully allocated, embedded cost of service study for natural gas service based on Delta's accounting costs per books, adjusted for known and measurable changes to test year operating results, for the 12 months ended December 31, 2009. The Commission has accepted in other rate case proceedings the methodology used in Delta's cost of service study. The objective in performing the cost of service study is to determine the rate of return on rate base that Delta is earning from each customer class, which provides an indication as to whether Delta's service rates reflect the cost of providing service to each customer class.

Q. Have you ever prepared an embedded cost of service study?

A. Yes, on many occasions. While employed at LG&E, I prepared numerous gas and electric cost of service studies, many of which were filed in rate cases before the Commission. Since leaving LG&E, I have prepared or supervised the preparation of well over 150 embedded cost of service studies for electric, gas and water utilities. In Kentucky, I supervised and participated in the preparation of gas cost of service studies for Delta (Case

Nos. 99-176, 2004-00067, and 2007-00089) and LG&E (Case Nos. 2000-080, 2003-00433, 2008-00252 and 2009-00549).

Q. Was the same methodology used in the cost of service study submitted in this proceeding that was used in the cost of service study filed by Delta in Case No. 2007-00089?

A. Yes. This is also the same methodology utilized by Delta in Case No. 2004-00067 and accepted by the Commission in that same proceeding in its Order dated November 10, 2004.

Q. Did you develop the model used to perform Delta's cost of service study?

A. Yes. I developed the spreadsheet model used to perform the cost of service study being submitted in this proceeding.

Q. What procedure was used in performing the cost of service study?

A. The cost of service study was prepared using the following basic procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups, (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to Delta's rate classes. This is a standard approach utilized in the preparation of embedded cost of service studies for gas utilities.

Q. What is the purpose of functionally assigning costs?

A. Functional assignment serves the following purposes: (1) it groups associated costs together to facilitate allocation on the basis of cost responsibility; (2) it provides a rational mechanism for grouping costs that do not appear to be related to major service functions; and (3) it provides a mechanism for separating assignable costs from joint costs, which must be allocated.

Q. What functional groups were used in the natural gas cost of service study?

A. The following standard functional groups were identified in the cost of service study: (1) Storage, (2) Transmission, (3) Distribution Commodity, (4) Distribution Structures and Equipment, (5) Distribution Mains, (6) Services, (7) Meters, (8) Customer Accounts, and (9) Customer Service Expense.

Q. How were costs classified as commodity related, demand related or customer related?

A. Classification provides a method of arranging costs so that the service characteristics which give rise to the costs can serve as a basis for allocation. Costs classified as *commodity related* tend to vary with the quantity of gas delivered, such as gas supply and the operation of compressors. Since gas supply costs were removed from the cost of service study, it was not necessary to classify gas supply costs. Costs classified as *demand related* are costs related to facilities installed to meet design-day usage requirements. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of gas purchased or the peak requirements of the customers. All transmission plant costs were classified as demand related. Distribution Structures and Equipment costs were classified as demand-related. Costs related to Distribution Mains were classified as demand-related and customer-related using the zero-intercept methodology. Services, Meters, Customer Accounts, and Customer Service Expenses were all classified as customer-related.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the cost of service study?

A. Yes. Seelye Exhibit 5 shows the results of the first two steps of the cost of service study: functional assignment and classification.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, Delta's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors." These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 5, Delta's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28 of Seelye Exhibit 5. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are shown on pages 29 and 30 of Seelye Exhibit 5. The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name."

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors." The results of the class allocation step of the cost of service study are included in Seelye Exhibit 6. The costs shown in the column labeled "Total System" in Seelye Exhibit 6 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 5. The column labeled "Ref" in Seelye Exhibit 6 provides a reference to the results included in Seelye Exhibit 5.

Q. Please describe the allocation factors used in the gas cost of service study.

A. The following allocation factors were used in the gas cost of service study herein:

- **DEM02** is used to allocate Storage demand-related costs and represents a composite allocation based on expected winter season requirements and design day demands. The class allocation factor is the sum of (a) the volumes (commodity) withdrawn from storage during the expected winter season, and (b) the volumes needed in storage to meet the design-day demands. The calculation of this allocation factor is shown on Seelye Exhibit 7.
- **DEM03** is used to allocate Transmission demand-related costs and is allocated on the basis of design-day demands determined at Delta's -3 degree F design-day mean temperature.
- **DEM04** is used to allocate Distribution Structures and Equipment demand-related costs and represents maximum class demands determined at Delta's -3 degree F design day mean temperature. These demands were calculated using base loads and temperature sensitive loads developed for the temperature normalization adjustment. The temperature normalization adjustment will be discussed later in my testimony.
- **DEM05** is used to allocate the demand-related portion of the cost of distribution mains and represents maximum class demands

determined at the design day mean temperature.

- **COM02** is used to allocate Storage commodity-related costs and represents actual customer class deliveries during the winter withdrawal season (defined as the months of December through March.)
- **COM03** is used to allocate Transmission commodity-related costs and represents annual throughput volumes (including both sales and transportation).
- **COM04** is used to allocate Distribution commodity-related costs and represents annual throughput volumes (including both sales and transportation) of customers served on the distribution system.
- **CUST01** is used to allocate the customer-related portion of Delta's distribution mains and represents the year-end number of customers.
- **CUST02** is used to allocate Services and is based on the total estimated cost of installing a service line per customer in each customer class weighted by the year-end number of customers in each class.
- **CUST03** is used to allocate Meters and is based on the estimated cost of meters and meter installation costs per customer in each customer class weighted by the year-end number of customers in each class.
- **CUST04** is used to allocate customer accounts expenses (Accounts 901 through 905) and is determined on the basis of the average number of customers.

- **CUST05** is used to allocate customer service expenses using the same allocation factor used to allocate Accounts 901, 902, 903, and 905 in CUST04.

Q. How are mains typically classified between demand and customer costs?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, a "minimum" standard pipe size is selected and the minimum system is obtained by pricing all of the distribution mains at the unit cost of this minimum size pipe. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the zero-intercept methodology, rather than the minimum system methodology, was used to determine the customer component of mains. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data is available. With the zero-intercept methodology, we are not forced to choose a minimum size main to determine the customer component. In the zero-intercept methodology, a zero-diameter pipe is the absolute minimum system.

Q. What is the theory behind the zero-intercept methodology?

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost ($/ft) of mains and the gas flow capability of the pipe, which is proportionate to its diameter. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the pipe,

x is the size of the pipe, and

a, b are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a pipe with zero diameter (or pipe with zero load carrying capability) is a, the zero intercept. The zero intercept is essentially the cost component of mains that is invariant to the size (and load carrying capability) of the pipe.

Like most gas distribution systems, the number of feet of mains on Delta's system is not uniformly distributed over all sizes of pipe. For example, Delta has over 4.6 million feet of 2-inch plastic mains, but only 89 thousand feet of 3-inch plastic mains. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Using a weighted regression analysis, the cost and diameter of each size pipe is, in effect, weighted by the number of feet of installed pipe. In a weighted regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where w is the weighting factor (in this case the feet of pipe) for each size of pipe, and y is the observed value and $\hat{y}$ is the predicted value of the dependent variable (in this case the unit cost of the pipe).

Attached as Seelye Exhibit 8 is the zero-intercept analysis used in this study. The zero-intercept unit cost of $5.65 per foot pipe is applied to the total feet of mains in the analysis to determine the customer cost component. The listing on page 1 of the analysis indicates that the coefficient of determination R-squared for mains is 0.9475. The coefficient of determination is a relative measure of the closeness of fit, where a coefficient of 0.0 indicates no linear correlation between the independent variable and dependent variable and a coefficient of 1.0 indicates perfect linear correlation.

Q. Has the Commission accepted the use of the zero-intercept methodology in previous cases?

A. Yes, on many occasions. The Commission accepted the methodology utilized by Delta in Case No. 2004-00067. LG&E utilized the zero-intercept methodology in the cost of service studies submitted in several rate cases (Case Nos. 2000-080 and 90-158) in which the Commission has issued orders and the Commission found them to be reasonable. LG&E utilized the same methodology in Case Nos. 2003-00433, 2008-00252 and 2009-00549. The Commission also found the embedded cost of service study submitted by The Union Light Heat and Power in its gas base rate case (Case No. 2001-00092), which utilized a zero-intercept methodology, to be reasonable. In my experience, the zero-intercept methodology is the predominant method used in Kentucky and is used widely in other jurisdictions.

Q. Please summarize the results of the gas cost of service study.

A. The following table (Table 2) summarizes the rates of return on net cost rate base for each customer class before and after reflecting the rate adjustments proposed by Delta. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 2 Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential	3.44%	8.19%
Small Non-Residential	5.51%	9.21%
Large Non-Residential	7.00%	10.64%
Interruptible	15.08%	15.08%
Special Contracts	0.79%	0.79%
Off-System Transportation	5.59%	7.26%
Total System	4.79%	8.66%

Q. Is the current actual rate of return for the residential class adequate?

A. No. As shown in Table 1, the actual adjusted rate of return for the residential class is below the rates of return for the other customer classes. Delta's overall adjusted rate of return is 4.79%, while the rate of return for the residential class is only 3.44%. In my opinion, Delta should be allowed to charge rates that bring the residential rate of return more in line with the overall rate of return.

Q. Would Delta's proposed rates move the company toward bringing the class rates of return closer together?

A. Yes. As Table 1 shows, the residential rates proposed by Delta result in a pro-forma rate of return of 8.19%, which brings the residential class within 47 basis points of the proposed overall rate of return of 8.66%. This is an improvement over the 1.35 percentage point difference between the current overall and residential rates of return of 4.79% and 3.44%, respectively.

IV. TEMPERATURE NORMALIZATION ADJUSTMENT

Q. Please explain the calculations and methodology used to determine the temperature normalization adjustment to test period revenue.

A. Delta has a Weather Normalization Adjustment ("WNA") clause that automatically adjusts the commodity charge to reflect normal temperatures. The WNA clause is applicable to residential and small non-residential customers and is currently applied during the months of December through April. Because the WNA automatically normalizes customer billings for these two rate classes during the months of December through April it is not necessary to perform a temperature normalization adjustment for these two classes during these months. However, it is necessary to perform a temperature normalization adjustment for the residential and small non-residential customer classes to reflect the heating months not covered by the WNA. Additionally, it is necessary to perform a temperature normalization adjustment for rate classes not billed under the WNA, namely, large non-residential and interruptible rate classes.

Q. How was the gas temperature normalization adjustment performed for the rate classes not billed under the WNA?

A. A standard temperature normalization adjustment covering the entire heating season was performed for the large non-residential and interruptible rate classes. Heating degree days related to cycle billed customer deliveries were 11 below the 30-year average Weather Bureau heating-degree days of 4,603 where the 30-year average was determined using the period ended December 31,2009. Thus, Delta's actual revenues for these rate classes were mildly understated due to slightly warmer than normal temperatures experienced during the test period. The degree-day data used for purposes of calculating the temperature normalization adjustment was obtained from the Lexington, Kentucky weather station.

The first step in computing the temperature-related variance in deliveries was to determine the annual non-temperature sensitive and temperature sensitive volumes for each rate class. The determination of the non-temperature sensitive volumes was based on the gas deliveries that occurred in July and August since those months had no heating degree days. The volumes in those two months were then multiplied by six to calculate an annual non-temperature sensitive load that was deducted from total deliveries to arrive at the annual temperature sensitive volumes.

The next step was to determine the volumetric adjustment required to normalize deliveries to reflect normal temperatures. The annual temperature sensitive volumes were divided by the actual heating degree days (4,592 for billing cycle customers) in the test period and the resulting Mcf per degree day was then multiplied by the degree-day departure from normal (11 HDDs) to arrive at the volumetric adjustment for each rate class. In the final step, the volumetric adjustment for each rate class was applied to the applicable distribution component (rate per Mcf) for each rate schedule not billed under the WNA.

Q. How was the gas temperature normalization adjustment performed for the residential and small non-residential rate classes, which are billed under the WNA?

A. The same methodology was used for the residential and small non-residential rate classes except that the difference in degree days was determined only for the months outside of the period when the WNA is applied. In other words the temperature normalization was only applied to the 7 non-WNA months of May through November. Since the WNA adjusts customer volumes during the months of December through April, it was not necessary to make a temperature normalization adjustment during these months. During the months of May through November, actual heating degree days related to cycle billed customer deliveries were 68 above the 30-year average Weather Bureau heating-degree days of 795 for those months. This difference was then used in the calculation of the temperature normalization adjustment for the residential and small non-residential rate classes.

Q. Please summarize the total impact of the gas temperature normalization adjustment.

A. The temperature normalization adjustment results in a net decrease of $63,111 to Delta's gas operating revenue. The calculation of this amount is summarized on Seelye Exhibit 9. The amount is also reflected by rate class and in total in Column 5 of Seelye Exhibit 3.

V. REVENUE ADJUSTMENT TO REFLECT YEAR-END CUSTOMERS

Q. Is Delta proposing to make a pro-forma adjustment to reflect the number of customers served at the end of the year?

A. No. Delta respectfully requests that a year-end customer adjustment not be made in this proceeding. The purpose of such an adjustment is to normalize annual revenues to reflect a going forward level of customers. The rationale for a year-end adjustment is to compare the number of customers at the end of the test year to the average number of customers during the test year. If the year-end level is higher than the average then it is assumed that the Company is adding customers and that the year-end level of customers and associated revenues is more appropriate than the average test-year level on a going-forward basis for purposes of setting rates. Delta does not believe that the year-end level of customers reflects an appropriate going forward level of customers. In fact, it is likely that the revenues associated with the year-end level will overstate Delta's going forward revenue because the year-end level of customers will almost certainly be higher than the average number of customers during the first full year that the rates go into effect.

In this proceeding, the year-end level of customers is higher than the average, but not because of customer growth; instead, it is because of the selection of the 12 months ended December as the test year. A significant number of customers disconnect service during the summer months and return to the system during the winter months. Because the test year in this proceeding ends in December – which is a winter month – using the year-end level of customers overstates the customer level that should be used for purposes of normalization. On the whole, Delta is not adding customers. In fact, Delta has been consistently losing customers over the past several years. In 2002, Delta's total average customer count was 40,185. By

2006, that number had declined to 38,117 and in the 2009 test year that number is 35,895. Based on this trend, one could expect that the number of customers served by Delta will continue to decrease, thus suggesting that a downward adjustment could be made to normalize revenues to reflect the number of customers served on a going forward basis. Delta is not proposing to make a downward revenue adjustment to reflect this trend, and requests that the Commission not make a year-end adjustment in this proceeding. The standard year-end adjustment is included in Seelye Exhibit 10 in the event that the Commission rejects the recommendation not to make a year-end adjustment.

VI. DEPRECIATION STUDY AND DEPRECIATION EXPENSE ADJUSTMENT

Q. Did you supervise the preparation of a depreciation study for Delta?

A. Yes.

Q. Was a standard methodology used to determine the depreciation accrual rates?

A. Yes. Where suitable information was available, the Simulated Plant Record (SPR) methodology was used to determine the survivor curve that best fit the plant retirement data for Delta's plant accounts. The SPR methodology is described in *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners and in other publications. Where sufficient data were not available, or the resulting statistics were not satisfactory, we relied heavily on comparisons to the survivor curves and depreciation rates utilized by neighboring gas utilities. The methodology used to develop the depreciation accrual rates is described in more detail in the report included in Seelye Exhibit 11.

Q. Was the same methodology used in this depreciation study as in study filed by Delta in its last two rate cases (Case Nos. 2004-00067 and 2007-00089)?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

Seelye Exhibit 1

Summary of Qualifications

William Steven Seelye

QUALIFICATIONS OF WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting services in the areas of tariff development, regulatory analysis revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 150 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility

	billing practices, and ISO billing processes and procedures.
Manager of Rates and Other Positions Louisville Gas & Electric Co. (May 1979 to July 1996)	Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Associations

Member of the Society for Industrial and Applied Mathematics

Expert Witness Testimony

Alabama:	Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.
Colorado:	Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.
FERC:	Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.
	Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.
	Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.
	Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.
	Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Submitted direct testimony in Cause No. 43773 on behalf of Crawfordsville Electric Light & Power regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

Submitted testimony in Case No. 2009-00040 on behalf of Big Rivers Electric Corporation regarding revenue requirements and rate design.

Submitted testimony on behalf of Columbia Gas Company of Kentucky in Case No. 2009-00141 regarding the demand side management program costs and cost recovery mechanism.

Submitted testimony in Case No. 2009-00548 on behalf of Kentucky Utilities Company and in Case No. 2009-00549 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Submitted testimony in NSUARB – NSPI – P-884 (2) on behalf of Nova Scotia Power Company's regarding a demand-side management cost recovery mechanism.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00029 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, general rate design, time of use rates, and excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00065 on behalf of Craig-Botetourt Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Seelye Exhibit 2

Reconstruction of
Billing Determinants

Delta Natural Gas Company, Inc.

Calculations to Verify Test Period Billing Determinants
For the 12 months Ended December 31, 2009

	(1) Actual Billed Revenue	(2) Elimination of Gas Cost Adjustment (See Gas Cost Exhibit)	(3) Billing Correction	(4) Revenue Excluding Gas Cost Adjustment (Column (1) + (2))	(5) Elimination of Weather Normalization Adjustment (See WNA Exhibit)	(6) Net Revenue (Column (3) + (4))	(7) Calculated Net Revenue (See Verification of Rates Exhibit)	(8) Correction Factor (Column (6) / Column (7))
REVENUE								
Residential	$ 30,606,864.00	$ (17,994,255.40)		$ 12,612,608.60	$ 71,470.00	$ 12,684,078.60	$ 12,487,172.45	0.98448
Small Non-Residential GS	9,073,688.00	(5,663,368.35)		3,410,319.65	15,561.00	3,425,880.65	3,384,458.10	0.98791
Large Non-Residential GS								
Large Non-Residential GS - Commercial	11,908,202.00	(8,082,382.97)		3,825,819.03	-	3,825,819.03	3,821,227.48	0.99880
Large Non-Residential GS - Industrial	1,203,947.00	(895,797.11)		308,149.89	-	308,149.89	308,031.29	0.99962
Total Large Non-Residential GS	13,112,149.00	(8,978,180.07)		4,133,968.93	-	4,133,968.93	4,129,258.77	
Interruptible								
Interruptible -Commercial	29,572.00	(24,285.70)		5,286.30	-	5,286.30	5,285.52	0.99985
Interruptible - Industrial	327,000.00	(275,248.31)	-	51,751.69	-	51,751.69	51,744.48	0.99986
Total Interruptible	356,572.00	(299,534.01)	-	57,037.99	-	57,037.99	57,030.00	
Unmetered Gas Lights								
Residential	5,249.00	(3,703.04)		1,545.96	-	1,545.96	1,546.78	1.00053
Commercial	3,766.00	(2,643.46)		1,122.54	-	1,122.54	1,024.65	0.91280
Small Commercial	5,274.00	(3,700.85)		1,573.15	-	1,573.15	1,434.51	0.91187
Unmetered Gas Lights	14,289.00	(10,047.35)		4,241.65		4,241.65	4,005.94	
Total Retail	$ 53,163,562.00	$ (32,945,385.18)	$ -	$ 20,218,176.82	$ 87,031.00	$ 20,305,207.82	$ 20,061,925.26	0.98802
Special Contracts	309,427.56			309,427.56		309,427.56	$ 309,427.56	1.00000
Small Non-Residential GS	186,481.17			186,481.17		186,481.17	186,481.08	1.00000
Large Non-Residential GS	2,203,535.47			2,203,535.47		2,203,535.47	2,203,556.59	1.00001
Residential	8,471.17			8,471.17		8,471.17	8,471.12	0.99999
Interuptible	1,427,028.92			1,427,028.92		1,427,028.92	1,420,339.32	0.99531
On System Transportation	4,134,944.29			4,134,944.29		4,134,944.29	4,128,275.67	
Off System Transportation	3,415,904.00			3,415,904.00		3,415,904.00	3,328,385.31	0.97438
Total Transportation	$ 7,550,848.29	$ -		$ 7,550,848.29	$ -	$ 7,550,848.29	$ 7,456,660.98	0.98753
Miscellaneous Revenue	$ 302,580.00	$ -		302,580.00		$ 302,580.00	$ 302,580.00	
Total Operating Revenue	$ 61,016,990.29	$ (32,945,385.18)	$ -	$ 28,071,605.11	$ 87,031.00	$ 28,158,636.11	$ 27,821,166.24	0.98802

MCF	(1)	(3)	(6)
Residential	1,650,148	9,040.00	1,650,148
Small Non-Residential GS	515,460		515,460
Large Non-Residential GS - Commercial	754,173		754,173
Large Non-Residential GS - Industrial	81,222		81,222
Interruptible - Commercial	2,210		2,210
Interruptible - Industrial	25,265		25,265
Unmetered Gas Lights - Total	1,020		1,020
Total Retail	3,029,498		3,029,498
On System Transportation Special	4,110,307		4,110,307
Off System Transportation	10,642,929		10,642,929
Total Transportation	14,753,236		14,753,236
Total	17,782,734		17,782,734

Seelye Exhibit 3

Summary of
Proposed Increase

Delta Natural Gas Company, Inc.

Summary of Rate Increase by Rate Class
Based on Adjusted Sales and Transportation for the 12 months Ended December 31, 2009

	(1) Actual Billed Revenue	(2) Elimination of Gas Cost Adjustment	(3) Correction	(4) Net Revenue Before Temperature Adjustment	(5) Temperature Adjustment	(6) GCR at Current Rates	(7) Adjusted Billings at Current Rates	(8) Increase in Revenue
		(See Gas Cost Exhibit)		(Column (1) + (2))	(See Temperature Normalization Exhibit)	6.0360	(Column (3) + (4) + (5))	
REVENUE								
Residential	$ 30,606,864	$ (17,994,255)		$ 12,612,609	$ (57,963)	$ 9,772,403	$ 22,327,049	$ 3,538,987
Small Non-Residential GS	9,073,688	(5,663,368)		3,410,320	(13,572)	3,069,026	6,465,774	593,145
Large Non-Residential GS								
Large Non-Residential GS - Commercial	11,908,202	(8,082,383)		3,825,819	4,894	4,559,291	8,390,004	628,392
Large Non-Residential GS - Industrial	1,203,947	(895,797)		308,150	640	491,187	799,977	40,167
Total Large Non-Residential GS	13,112,149	(8,978,180)		4,133,969	5,534	5,050,478	9,189,981	668,559
Interruptible								
Interruptible - Commercial	29,572	(24,286)		5,286	-	13,338	18,624	-
Interruptible - Industrial	327,000	(275,248)	-	51,752	53	152,699	204,503	-
Total Interruptible	356,572	(299,534)	-	57,038	53	166,036	223,127	-
Unmetered Gas Lights								
Residential	5,249	(3,703)		1,546		2,245	3,791	65
Commercial	3,766	(2,643)		1,123		1,630	2,752	159
Small Commercial	5,274	(3,701)		1,573		2,282	3,855	223
Unmetered Gas Lights	14,289	(10,047)		4,242		6,157	10,398	448
Total Retail	$ 53,163,562	$ (32,945,385)	$ -	$ 20,218,177	$ (65,947)	$ 18,064,101	$ 38,216,330	$ 4,801,139
Special Contracts	$ 309,428	$ -		$ 309,428	$ -	$ -	$ 309,428	$ -
Small Non-Residential GS	186,481	-		186,481	366	-	186,847	18,165
Large Non-Residential GS	2,203,535	-		2,203,535	2,470	-	2,206,005	241,036
Residential	8,471	-		8,471	-	-	8,471	2,058
Interruptible	1,427,029	-		1,427,029	-	-	1,427,029	-
On System Transportation	4,134,944	-		4,134,944	2,836	-	4,137,780	261,259
Off System Transportation	3,415,904	-		3,415,904	-	-	3,415,904	253,030
Total Transportation	$ 7,550,848	$ -		$ 7,550,848	$ 2,836	$ -	$ 7,553,684	$ 514,289
Miscellaneous Revenue	$ 302,580	$ -		$ 302,580			$ 302,580	$ -
Total Operating Revenue	$ 61,016,990	$ (32,945,385)	$ -	$ 28,071,605	$ (63,111)	$ 18,064,101	$ 46,072,595	$ 5,315,428

Seelye Exhibit 4

Calculated Billings at
Proposed Rates

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

Residential

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	367,703	$ 15.30	$ 5,625,855.90	$ 24.00	$ 24.00	$ 8,824,872.00
Commodity Charge	*Mcf*					
All Mcf	1,650,148	$ 4.1580	6,861,316.55	$ 4.3344	$ 0.4334	7,151,742.65
Calculated Billings at Base Rates			$ 12,487,172.45			$ 15,976,614.65
Correction Factor -(Calculated / Actual)		*0.98448*		*0.98448*		
Total After Application of Correction Factor			$ 12,684,078.60			$ 16,228,544.68
Temperature Normalization						
All Mcf	(31,129)	$ 4.1580	(129,432.52)	$ 4.3344	$ 0.4334	(134,911.15)
	Mcf					
Adjusted Billings at Base Rates	1,619,020		$ 12,554,646.08			$ 16,093,633.53
GCR at Current Rates	1,619,020	6.0360	9,772,403.08	6.0360	$ 0.6036	9,772,403.08
Total Adjusted Billings at Base Rates			$ 22,327,049.16			$ 25,866,036.61
Increase in Revenue						$ 3,538,987.45
						15.9%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

Small Non-Residential General Service

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	49,647	$ 25.00	$ 1,241,175.00	$ 35.00	$ 35.00	$ 1,737,645.00
Commodity Charge	***Mcf***					
All Mcf	515,460	$ 4.1580	2,143,283.10	$ 4.3344	$ 0.4334	2,234,004.07
Calculated Billings at Base Rates	515,460		$ 3,384,458.10			$ 3,971,649.07
Correction Factor -(Calculated / Actual)		*0.98791*		*0.9879*		
Total After Application of Correction Factor			$ 3,425,880.65			$ 4,020,258.28
Temperature Normalization						
First 200 Mcf	(7,006)	$ 4.1580	(29,132.71)	$ 4.3344	$ 0.4334	(30,365.84)
	Mcf					
Adjusted Billings at Base Rates	508,454		$ 3,396,747.94			$ 3,989,892.44
GCR at Current Rates	508,454	6.0360	3,069,026.39	6.0360	$ 0.6036	3,069,026.39
Total Adjusted Billings at Base Rates			$ 6,465,774.33			$ 7,058,918.83
Increase in Revenue						$ 593,144.50
						9.2%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

Large Non-Residential General Service - Commercial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	9,891	$ 100.00	$ 989,100.00	$ 150.00	$ 150.00	$ 1,483,650.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	577,069	$ 4.1580	2,399,450.82	$ 4.3344	$ 0.4334	2,501,014.88
Next 800 Mcf	162,413	$ 2.5091	407,510.46	$ 2.6855	$ 0.2686	436,241.32
Next 4,000 Mcf	14,691	$ 1.7130	25,166.20	$ 1.8894	$ 0.1889	27,751.87
Next 5,000 Mcf	-	$ 1.3130	-	$ 1.4894	$ 0.1489	-
Over 10,000 Mcf	-	$ 1.1130	-	$ 1.2894	$ 0.1289	-
Calculated Billings at Base Rates	754,173		$ 3,821,227.48			$ 4,448,658.07
Correction Factor -(Calculated / Actual)		*0.9988*		*0.9988*		
Total After Application of Correction Factor			$ 3,825,819.03			$ 4,454,003.54
Temperature Normalization						
First 200 Mcf	1,177	$ 4.1580	4,893.97	$ 4.3344	$ 0.4334	5,101.12
	Mcf					
Adjusted Billings at Base Rates	755,350		$ 3,830,713.00			$ 4,459,104.66
GCR at Current Rates	755,350	6.0360	4,559,291.39	6.0360	0.6036	4,559,291.39
			$ 8,390,004.39			$ 9,018,396.05
Increase in Revenue						$ 628,391.66
						7.5%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

Large Non-Residential General Service - Industrial

	Customers	*Present Rate*	*Calculated Net Revenue@ Present Rates*	*Proposed Rate*	*Proposed Rate Per Ccf*	*Calculated Net Revenue@ Proposed Rates*
Customer Charge	516	$ 100.00	$ 51,600.00	$ 150.00	$ 150.00	$ 77,400.00
Commodity Charge	***Mcf***	***Present Rate***				
First 200 Mcf	37,318	$ 4.1580	155,167.83	$ 4.3344	$ 0.4334	161,735.78
Next 800 Mcf	32,729	$ 2.5091	82,119.83	$ 2.6855	$ 0.2686	87,909.56
Next 4,000 Mcf	11,176	$ 1.7130	19,143.63	$ 1.8894	$ 0.1889	21,110.52
Next 5,000 Mcf	-	$ 1.3130	-	$ 1.4894	$ 0.1489	-
Over 10,000 Mcf	-	$ 1.1130	-	$ 1.2894	$ 0.1289	-
Calculated Billings at Base Rates	81,222		$ 308,031.29			$ 348,155.86
Correction Factor -(Calculated / Actual)		*0.99962*		*0.99962*		
Total After Application of Correction Factor			$ 308,149.89			$ 348,289.91
Temperature Normalization						
First 200 Mcf	154	$ 4.1580	640.33	$ 4.3344	$ 0.4334	667.44
	Mcf					
Adjusted Billings at Base Rates	81,376		$ 308,790.22			$ 348,957.35
GCR at Current Rates	81,376	6.0360	491,186.74	6.0360	0.6036	491,186.74
			$ 799,976.96			$ 840,144.09
Increase in Revenue						$ 40,167.13
						5.0%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

Interruptible Service - Commercial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	7	$ 250.00	$ 1,750.00	$ 250.00	$ 250.00	$ 1,750.00
	Mcf	*Present Rate*				
Commodity Charge						
First 1,000 Mcf	2,210	$ 1.6000	3,535.52	$ 1.6000	$ 0.1600	3,535.52
Next 4,000 Mcf	-	$ 1.2000	-	$ 1.2000	$ 0.1200	-
Next 5,000 Mcf	-	$ 0.8000	-	$ 0.8000	$ 0.0800	-
Over 10,000 Mcf	-	$ 0.6000	-	$ 0.6000	$ 0.0600	-
Calculated Billings at Base Rates	2,210		$ 5,285.52			$ 5,285.52
Correction Factor -(Calculated / Actual)		*0.99985*		*0.99985*		
Total After Application of Correction Factor			$ 5,286.30			$ 5,286.30
Temperature Normalization						
First 1,000 Mcf	0	$ 1.6000	-	$ 1.6000	$ 0.1600	-
	Mcf					
Adjusted Billings at Base Rates	2,210		$ 5,286.30			$ 5,286.30
GCR at Current Rates	2,210	6.0360	13,337.75	6.0360	0.6036	13,337.75
			$ 18,624.05			$ 18,624.05
Increase in Revenue						$ -
						0.0%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

Interruptible Service - Industrial

	Customers	*Present Rate*	*Calculated Net Revenue@ Present Rates*	*Proposed Rate*	*Proposed Rate Per Ccf*	*Calculated Net Revenue@ Proposed Rates*
Customer Charge	55	$ 250.00	$ 13,750.00	$ 250.00	$ 250.00	$ 13,750.00
Commodity Charge	*Mcf*	*Present Rate*				
First 1,000 Mcf	19,191	$ 1.6000	30,705.92	$ 1.6000	$ 0.1600	30,705.92
Next 4,000 Mcf	6,074	$ 1.2000	7,288.56	$ 1.2000	$ 0.1200	7,288.56
Next 5,000 Mcf	-	$ 0.8000	-	$ 0.8000	$ 0.0800	-
Over 10,000 Mcf	-	$ 0.6000	-	$ 0.6000	$ 0.0600	-
Calculated Billings at Base Rates	25,265		$ 51,744.48			$ 51,744.48
Correction Factor -(Calculated / Actual)		*0.99986*		*0.99986*		
Total After Application of Correction Factor			$ 51,751.69			$ 51,751.69
Temperature Normalization						
First 1,000 Mcf	33	$ 1.6000	52.80	$ 1.6000	$ 0.1600	52.80
	Mcf					
Adjusted Billings at Base Rates	25,298		$ 51,804.49			$ 51,804.49
GCR at Current Rates	25,298	6.0360	152,698.73	6.0360	0.6036	152,698.73
			$ 204,503.22			$ 204,503.22
Increase in Revenue						$ -
						0.0%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

Unmetered Gas Lights - Residential

	Lights	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	248	$ -	$ -	$ -		$ -
	Mcf	***Present Rate***				
Commodity Charge						
All Mcf	372	$ 4.1580	1,546.78	$ 4.3344	$ 0.4334	1,612.25
Calculated Billings at Base Rates			$ 1,546.78			$ 1,612.25
Correction Factor -(Calculated / Actual)		*1.00053*		*1.00053*		
Total After Application of Correction Factor			$ 1,545.96			$ 1,611.40
Temperature Normalization	-		-	$ -		-
	Mcf					
Adjusted Billings at Base Rates	372		$ 1,545.96			$ 1,611.40
GCR at Current Rates	372	6.0360	2,245.39	6.0360	0.6036	2,245.39
			$ 3,791.35			$ 3,856.79
Increase in Revenue						$ 65.44
						1.7%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

Unmetered Gas Lights - Commercial

	Lights	Present Rate		Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf		Calculated Net Revenue@ Proposed Rates
Customer Charge	24	$ -	$	-	$ -		$	-
	Mcf	**Present Rate**						
Commodity Charge All Mcf	270	$ 3.7950		1,024.65	$ 4.3344	$ 0.4334		1,170.18
Calculated Billings at Base Rates			$	1,024.65			$	1,170.18
Correction Factor -(Calculated / Actual)		0.91280			0.91280			
Total After Application of Correction Factor			$	1,122.54			$	1,281.97
Temperature Normalization	-			-	$ -			-
	Mcf							
Adjusted Billings at Base Rates	270		$	1,122.54			$	1,281.97
GCR at Current Rates	270	6.0360		1,629.72	6.0360	0.6036		1,629.72
			$	2,752.26			$	2,911.69
Increase in Revenue							$	159.43
								5.8%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

Unmetered Gas Lights - Small Commercial

	Lights	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	36	$ -	$ -	$ -		$ -
Commodity Charge	*Mcf*	*Present Rate*				
All Mcf	378	$ 3.7950	1,434.51	$ 4.3344	$ 0.4334	1,638.25
Calculated Billings at Base Rates			$ 1,434.51			$ 1,638.25
Correction Factor -(Calculated / Actual)		*0.91187*		*0.91187*		
Total After Application of Correction Factor			$ 1,573.15			$ 1,796.58
Temperature Normalization	-		-	$ -		-
	Mcf					
Adjusted Billings at Base Rates	378		$ 1,573.15			$ 1,796.58
GCR at Current Rates	378	6.0360	2,281.61	6.0360	0.6036	2,281.61
			$ 3,854.76			$ 4,078.19
Increase in Revenue						$ 223.43
						5.8%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

On System Transportation

Special Contracts (4)

	Customers	Mcf			Net Margin@ Present Rates			Net Margin@ Proposed Rates
	48	1,955,008						
Calculated Billings at Base Rates				$	309,427.56		$	309,427.56
Correction Factor -(Calculated / Actual)			*1.00000*			*1.00000*		
Total After Application of Correction Factor				$	309,427.56		$	309,427.56

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

On System Transportation
Small Non Residential General Service -Transportation

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	1,147	$ 25.00	$ 28,675.00	$ 35.00	$ 35.00	$ 40,145.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	37,952	$ 4.1580	157,806.08	$ 4.3344	$ 0.4334	164,485.70
Next 800 Mcf	-	$ 2.5091	-	$ 2.6855	$ 0.2686	-
Next 4,000 Mcf	-	$ 1.7130	-	$ 1.8894	$ 0.1889	-
Next 5,000 Mcf	-	$ 1.3130	-	$ 1.4894	$ 0.1489	-
Over 10,000 Mcf	-	$ 1.1130	-	$ 1.2894	$ 0.1289	-
Calculated Billings at Base Rates	37,952		$ 186,481.08			$ 204,630.70
Correction Factor -(Calculated / Actual)		*1.00000*		*1.00000*		
Total After Application of Correction Factor			$ 186,481.17			$ 204,630.80
Temperature Normalization						
First 200 Mcf	88.00	$ 4.1580	365.90	$ 4.3344	$ 0.4334	381.39
	Mcf					
Adjusted Billings at Base Rates	37,952		$ 186,847.07			$ 205,012.19
Increase in Revenue						$ 18,165.12
						9.7%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

On System Transportation

Large Non Residential General Service -Transportation

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	1,053	$ 100.00	$ 105,300.00	$ 150.00	$ 150.00	$ 157,950.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	100,565	$ 4.1580	418,150.52	$ 4.3344	$ 0.4334	435,850.01
Next 800 Mcf	212,444	$ 2.5091	533,042.74	$ 2.6855	$ 0.2686	570,624.05
Next 4,000 Mcf	453,128	$ 1.7130	776,207.41	$ 1.8894	$ 0.1889	855,957.85
Next 5,000 Mcf	170,468	$ 1.3130	223,823.83	$ 1.4894	$ 0.1489	253,826.11
Over 10,000 Mcf	132,104	$ 1.1130	147,032.09	$ 1.2894	$ 0.1289	170,282.44
Calculated Billings at Base Rates	1,068,708		$ 2,203,556.59			$ 2,444,490.46
Correction Factor -(Calculated / Actual)		*1.00001*		*1.00001*		
Total After Application of Correction Factor			$ 2,203,535.47			$ 2,444,467.03
Temperature Normalization						
First 200 Mcf	594	$ 4.1580	2,469.85	$ 4.3344	$ 0.4334	2,574.40
	Mcf					
Adjusted Billings at Base Rates	1,068,708		$ 2,206,005.32			$ 2,447,041.43
Increase in Revenue						$ 241,036.11
						10.9%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

On System Transportation
Residential

	Customers	***Present Rate***			***Calculated Net Revenue@ Present Rates***		***Proposed Rate***		***Proposed Rate Per Ccf***		***Calculated Net Revenue@ Proposed Rates***
Customer Charge	211	$	15.30	$	3,228.30	$	24.00	$	24.00	$	5,064.00
Commodity Charge	***Mcf***	***Present Rate***									
All Mcf	1,261	$	4.1580		5,242.82	$	4.3344	$	0.4334		5,464.74
Calculated Billings at Base Rates				$	8,471.12					$	10,528.74
Correction Factor -(Calculated / Actual)			*0.99999*				*0.99999*				
Total After Application of Correction Factor				$	8,471.17					$	10,528.80
Temperature Normalization											
All Mcf		$	4.1580		-	$	4.3344	$	0.4334		-
	Mcf										
Adjusted Billings at Base Rates	1,261			$	8,471.17					$	10,528.80
Increase in Revenue										$	2,057.63
											24.3%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2009

On System Transportation
Interruptible Service - Transportation

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	424	$ 250.00	$ 106,000.00	$ 250.00	$ 250.00	$ 106,000.00
Commodity Charge	*Mcf*	*Present Rate*				
First 1,000 Mcf	301,642	$ 1.6000	482,627.68	$ 1.6000	$ 0.1600	482,627.68
Next 4,000 Mcf	593,018	$ 1.2000	711,621.72	$ 1.2000	$ 0.1200	711,621.72
Next 5,000 Mcf	142,299	$ 0.8000	113,839.12	$ 0.8000	$ 0.0800	113,839.12
Over 10,000 Mcf	10,418	$ 0.6000	6,250.80	$ 0.6000	$ 0.0600	6,250.80
Calculated Billings at Base Rates	1,047,377		$ 1,420,339.32			$ 1,420,339.32
Correction Factor -(Calculated / Actual)		*0.99531*		*0.99531*		
Total After Application of Correction Factor			$ 1,427,028.92			$ 1,427,028.92
Temperature Normalization						
First 1,000 Mcf		$ 1.6000	-	$ 1.6000	$ 0.1600	-
	Mcf					
Adjusted Billings at Base Rates	1,047,377		$ 1,427,028.92			$ 1,427,028.92
Increase in Revenue						$ -
						0.0%

Seelye Exhibit 5

Class Cost of Service Study

Functional Assignment
& Classification

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Gas Plant at Original Cost									
Underground Storage Plant									
350-358 Underground Storage Plant	PT350	F003	$ 14,934,082	14,934,082	-	-	-	-	-
Total Storage Plant	PTST		$ 14,934,082	$ 14,934,082	$ -	$ -	$ -	$ -	$ -
Transmission Plant									
325-371 Transmission	PT365	F005	$ 57,620,977	-	-	57,620,977	-	-	-
Distribution Plant									
374 & 304 Land and Land Rights	PT374	F008	$ 327,685	-	-	-	-	-	327,685
375 Structures & Improvements	PT375	F008	112,359	-	-	-	-	-	112,359
376 Mains	PT376	F009	66,875,339	-	-	-	-	-	-
378 Meas. & Reg. Sta. Equip. - General	PT378	F008	1,435,143	-	-	-	-	-	1,435,143
379 Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	500,033	-	-	-	-	-	500,033
380 Services	PT380	F010	13,709,009	-	-	-	-	-	-
381 Meters	PT381	F011	9,302,928	-	-	-	-	-	-
382 Meter Installations	PT382	F011	3,186,037	-	-	-	-	-	-
383 House Regulators	PT383	F011	3,478,550	-	-	-	-	-	-
384 House Regulator Installations	PT384	F011	-	-	-	-	-	-	-
385 Industrial Meas. & Reg. Equip.	PT385	F011	1,597,032	-	-	-	-	-	-
387 Other Equipment	PT387	F011	80,914	-	-	-	-	-	-
Mt. Olivet	MTOVT		-	-	-				
Sub-Total Distribution Plant	PTDSUB		$ 100,605,029	-	-	-	-	-	2,375,221
Transmission & Distribution Subtotal	TDSUB		$ 158,226,007	$ -	$ -	$ 57,620,977	$ -	$ -	$ 2,375,221
U-T-D Subtotal	PTSUB		$ 173,160,089	14,934,082	-	57,620,977	-	-	2,375,221
117 Gas Stored Underground/Non-Current	PT117	F003	$ 4,208,069	4,208,069	-	-	-	-	-
301-303 Intangible Plant	PT301	PTSUB	53,151	4,584	-	17,686	-	-	729
389-399 General Plant	PT389	PTSUB	21,242,491	1,832,045	-	7,068,679	-	-	291,381
Common Utility Plant	PTCP	PTSUB	-	-	-	-	-	-	-
Total Plant in Service	PTIS		$ 198,663,799	20,978,780	-	64,707,343	-	-	2,667,331

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Gas Plant at Original Cost								
Underground Storage Plant								
350-358 Underground Storage Plant	PT350	F003	-	-	-	-	-	-
Total Storage Plant	PTST		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant								
325-371 Transmission	PT365	F005	-	-	-	-	-	-
Distribution Plant								
374 & 304 Land and Land Rights	PT374	F008	-	-	-	-	-	-
375 Structures & Improvements	PT375	F008	-	-	-	-	-	-
376 Mains	PT376	F009	22,209,300	44,666,039	-	-	-	-
378 Meas. & Reg. Sta. Equip. - General	PT378	F008	-	-	-	-	-	-
379 Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	-	-	-	-	-	-
380 Services	PT380	F010	-	-	13,709,009	-	-	-
381 Meters	PT381	F011	-	-	-	9,302,928	-	-
382 Meter Installations	PT382	F011	-	-	-	3,186,037	-	-
383 House Regulators	PT383	F011	-	-	-	3,478,550	-	-
384 House Regulator Installations	PT384	F011	-	-	-	-	-	-
385 Industrial Meas. & Reg. Equip.	PT385	F011	-	-	-	1,597,032	-	-
387 Other Equipment	PT387	F011	-	-	-	80,914	-	-
Mt. Olivet	MTOVT		-	-	-	-	-	-
Sub-Total Distribution Plant	PTDSUB		22,209,300	44,666,039	13,709,009	17,645,461	-	-
Transmission & Distribution Subtotal	TDSUB		$ 22,209,300	$ 44,666,039	$ 13,709,009	$ 17,645,461	$ -	$ -
U-T-D Subtotal	PTSUB		22,209,300	44,666,039	13,709,009	17,645,461	-	-
117 Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-	-	-
301-303 Intangible Plant	PT301	PTSUB	6,817	13,710	4,208	5,416	-	-
389-399 General Plant	PT389	PTSUB	2,724,536	5,479,426	1,681,759	2,164,665	-	-
Common Utility Plant	PTCP	PTSUB	-	-	-	-	-	-
Total Plant in Service	PTIS		24,940,653	50,159,175	15,394,975	19,815,542	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Gas Plant at Original Cost (Continued)										
Construction Work In Progress										
Underground Storage	CWIPUS	F003	$	-	-	-	-	-	-	-
Transmission	CWIPTR	F005	$	71,157	-	-	71,157	-	-	-
Distribution Mains	CWIPDM	F009	$	(38,587)	-	-	-	-	-	-
Other Distribution	CWIPOD	PTDSUB	$	27,411	-	-	-	-	-	647
General	CWIPCO	PT389	$	441,990	38,119	-	147,077	-	-	6,063
Total CWIP	CWIP		$	501,971	38,119	-	218,234	-	-	6,710
Total Gas Plant at Original Cost	PTT		$	199,165,770	21,016,899	-	64,925,577	-	-	2,674,041

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Gas Plant at Original Cost (Continued)								
Construction Work In Progress								
Underground Storage	CWIPUS	F003	-	-	-	-	-	-
Transmission	CWIPTR	F005	-	-	-	-	-	-
Distribution Mains	CWIPDM	F009	(12,815)	(25,772)	-	-	-	-
Other Distribution	CWIPOD	PTDSUB	6,051	12,170	3,735	4,808	-	-
General	CWIPCO	PT389	56,689	114,010	34,992	45,040	-	-
Total CWIP	CWIP		49,926	100,407	38,727	49,848	-	-
Total Gas Plant at Original Cost	PTT		24,990,578	50,259,582	15,433,703	19,865,390	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Net Cost Rate Base									
Total Gas Utility Plant at Original Cost			$ 199,165,770	$ 21,016,899	$ -	$ 64,925,577	$ -	$ -	$ 2,674,041
Less:									
Reserve for Depreciation									
Underground Storage	DEPRUS	PTST	$ 5,126,945	5,126,945	-	-	-	-	-
Transmission	DEPTR	F005	20,483,644	-	-	20,483,644	-	-	-
Distribution	DEPRDI	PTDSUB	33,817,598	-	-	-	-	-	798,412
General	DEPRGE	PT389	10,824,054	933,514	-	3,601,826	-	-	148,473
Common	DEPRCO	PTCP	-	-	-	-	-	-	-
Total Depreciation Reserve	DEPR		$ 70,252,241	$ 6,060,459	$ -	$ 24,085,470	$ -	$ -	$ 946,884
Depreciation Adjustment		DEPR	$ 1,112,824	96,000	-	381,524	-	-	14,999
Customer Advances For Construction	CAD	CADAL	$ 54,605	-	-	-	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	29,427,209	2,537,931	-	9,792,237	-	-	403,650
Investment Tax Credit	ITC	PTSUB	-	-	-	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB	-	-	-	-	-	-	-
PLUS:									
Materials and Supplies	MSP	PTSUB	$ 596,121	51,412	-	198,366	-	-	8,177
Prepayments	PPY	PTSUB	1,631,711	140,726	-	542,970	-	-	22,382
Gas Stored Underground	GSU	F003	3,777,901	3,777,901	-	-	-	-	-
Cash Working Capital	CWC	OMT	1,658,306	56,576	170,895	403,413	56,991	13,064	18,221
Adjustments:									
Unamortized Debt		PTSUB	$ 4,542,382	391,755	-	1,511,529	-	-	62,307
Utility ARO Assets		PTT	$ (138,345)	(14,599)	-	(45,099)	-	-	(1,857)
A/D on ARO Assets		DEPR	$ 134,408	11,595	-	46,081	-	-	1,812
Net Cost Rate Base	NCRB		$ 110,521,375	$ 16,737,875	$ 170,895	$ 33,323,606	$ 56,991	$ 13,064	$ 1,419,548

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Net Cost Rate Base								
Total Gas Utility Plant at Original Cost			$ 24,990,578	$ 50,259,582	$ 15,433,703	$ 19,865,390	$ -	$ -
Less:								
Reserve for Depreciation								
Underground Storage	DEPRUS	PTST	-	-	-	-	-	-
Transmission	DEPTR	F005	-	-	-	-	-	-
Distribution	DEPRDI	PTDSUB	7,465,483	15,014,141	4,608,177	5,931,385	-	-
General	DEPRGE	PT389	1,388,280	2,792,027	856,936	1,102,999	-	-
Common	DEPRCO	PTCP	-	-	-	-	-	-
Total Depreciation Reserve	DEPR		$ 8,853,763	$ 17,806,168	$ 5,465,112	$ 7,034,384	$ -	$ -
Depreciation Adjustment		DEPR	140,247	282,057	86,570	111,427	-	-
Customer Advances For Construction	CAD	CADAL	15,049	30,266	9,289	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	3,774,298	7,590,646	2,329,739	2,998,709	-	-
Investment Tax Credit	ITC	PTSUB	-	-	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB	-	-	-	-	-	-
PLUS:								
Materials and Supplies	MSP	PTSUB	76,458	153,767	47,195	60,746	-	-
Prepayments	PPY	PTSUB	209,281	420,894	129,182	166,276	-	-
Gas Stored Underground	GSU	F003	-	-	-	-	-	-
Cash Working Capital	CWC	OMT	178,981	359,956	103,170	144,343	152,473	224
Adjustments:								
Unamortized Debt		PTSUB	582,600	1,171,692	359,618	462,880	-	-
Utility ARO Assets		PTT	(17,359)	(34,911)	(10,721)	(13,799)	-	-
A/D on ARO Assets		DEPR	16,939	34,067	10,456	13,458	-	-
Net Cost Rate Base	NCRB		$ 13,254,121	$ 26,655,910	$ 8,181,893	$ 10,554,775	$ 152,473	$ 224

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Labor Expenses										
Production Expenses										
Operation & Maintenance										
753	Wells and Gathering	LB 753	F006	21,827	-	-	-	21,827	-	-
754	Compressor Station	LB754	F006	102,954	-	-	-	102,954	-	-
764	Maintenance of Wells and Gathering	LB764	F006	166	-	-	-	166	-	-
765	Maintenance of Compressor Station	LB765	F006	3,525	-	-	-	3,525	-	-
Total Production Operation & Maintenance Expenses				128,472	-	-	-	128,472	-	-
807-813	Procurement Expenses	LB807	DMCM	$ -	-	-	-	-	-	-
Storage Expenses										
Operation										
814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-	-	-	-
815	Maps and Records	LB815	F003	-	-	-	-	-	-	-
816	Well Expenses	LB816	F003	97,523	97,523	-	-	-	-	-
817	Lines Expenses	LB817	F003	-	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	20,175	-	20,175	-	-	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-	-
821	Purification of Natural Gas	LB821	F004	-	-	-	-	-	-	-
823	Gas losses	LB823	F004	-	-	-	-	-	-	-
824	Other Expenses	LB824	F004	-	-	-	-	-	-	-
825	Storage Well Royalities	LB825	F003	-	-	-	-	-	-	-
826	Rents	LB826	F003	-	-	-	-	-	-	-
Total Storage Operation Labor		LBSO		$ 117,698	$ 97,523	$ 20,175	$ -	$ -	$ -	$ -
Storage Expense										
Maintenance										
830	Maintenance Super and Eng.	LB830	MSE	$ -	-	-	-	-	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	613	613	-	-	-	-	-
833	Maintenance of Lines	LB833	F003	-	-	-	-	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	1,494	-	1,494	-	-	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	427	427	-	-	-	-	-
836	Main of Purification Equip	LB836	F004	-	-	-	-	-	-	-
837	Main of Other Equipment	LB837	F003	-	-	-	-	-	-	-
Total Maintenance Labor		LBSM		$ 2,534	$ 1,040	$ 1,494	$ -	$ -	$ -	$ -
Total Storage Labor		LBS		$ 120,232	98,563	21,669	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses									
Production Expenses									
Operation & Maintenance									
753	Wells and Gathering	LB 753	F006	-	-	-	-	-	-
754	Compressor Station	LB754	F006	-	-	-	-	-	-
764	Maintenance of Wells and Gathering	LB764	F006	-	-	-	-	-	-
765	Maintenance of Compressor Station	LB765	F006	-	-	-	-	-	-
Total Production Operation & Maintenance Expenses				-	-	-	-	-	-
807-813	Procurement Expenses	LB807	DMCM	-	-	-	-	-	-
Storage Expenses									
Operation									
814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-	-	-
815	Maps and Records	LB815	F003	-	-	-	-	-	-
816	Well Expenses	LB816	F003	-	-	-	-	-	-
817	Lines Expenses	LB817	F003	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	-	-	-	-	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-
821	Purification of Natural Gas	LB821	F004	-	-	-	-	-	-
823	Gas losses	LB823	F004	-	-	-	-	-	-
824	Other Expenses	LB824	F004	-	-	-	-	-	-
825	Storage Well Royalities	LB825	F003	-	-	-	-	-	-
826	Rents	LB826	F003	-	-	-	-	-	-
Total Storage Operation Labor		LBSO		$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense									
Maintenance									
830	Maintenance Super and Eng.	LB830	MSE	-	-	-	-	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	-	-	-	-	-	-
833	Maintenance of Lines	LB833	F003	-	-	-	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	-	-	-	-	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	-	-	-	-	-	-
836	Main of Purification Equip	LB836	F004	-	-	-	-	-	-
837	Main of Other Equipment	LB837	F003	-	-	-	-	-	-
Total Maintenance Labor		LBSM		$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Labor		LBS		-	-	-	-	-	-

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Labor Expenses (Continued)									
Transmission									
850-867 Transmission Expenses	LB850	F005	$ -	-	-	-	-	-	-
Distribution Expenses									
Operation									
870 Operation Supr and Engr	LB870	DOES	$ -	-	-	-	-	-	-
871 Dist Load Dispatching	LB871	F007	-	-	-	-	-	-	-
872 Compr. Station Labor and Exp.	LB872	F007	-	-	-	-	-	-	-
873 Compr. Station Fuel and Power	LB873	F007	-	-	-	-	-	-	-
874.01 Other Mains/Serv. Expenses	LB874.01	CADAL	-	-	-	-	-	-	-
874.02 Leak Survey-Mains	LB874.02	F009	-	-	-	-	-	-	-
874.03 Leak Survey - Service	LB874.03	F010	-	-	-	-	-	-	-
874.04 Locate Main per Request	LB874.04	CADAL	-	-	-	-	-	-	-
874.05 Check Stop Box Access	LB874.05	F010	-	-	-	-	-	-	-
874.06 Patrolling Mains	LB874.06	F009		-	-	-	-	-	-
874.07 Check/Grease Valves	LB874.07	F009	-	-	-	-	-	-	-
874.08 Opr. Odor Equipment	LB874.08	F007	-	-	-	-	-	-	-
874.09 Locate and Inspect Valve Boxes	LB874.09	F009	-	-	-	-	-	-	-
874.1 Cut Grass - Right of Way	LB874.10	F009	-	-	-	-	-	-	-
875 Meas and Reg Station Exp.- General	LB875	F008	-	-	-	-	-	-	-
876 Meas and Reg Station Exp.- Industrial	LB876	F011	-	-	-	-	-	-	-
877 Meas and Reg Station Exp. - City Gate	LB877	F008	-	-	-	-	-	-	-
878 Meter and House Reg. Expense	LB878	F011	-	-	-	-	-	-	-
879 Customer Installation Expense	LB879	F011	-	-	-	-	-	-	-
880 Other Expenses	LB880	PTDSUB	-	-	-	-	-	-	-
881 Rents	LB881	PTDSUB	-	-	-	-	-	-	-
Total Operations Distribution Labor	LBDO		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operations Transmission and Distribution Labor	LBTDO		$ 124,781	$ -	$ -	$ -	$ 124,781	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)									
Transmission									
850-867	Transmission Expenses	LB850	F005	-	-	-	-	-	-
Distribution Expenses									
Operation									
870	Operation Supr and Engr	LB870	DOES	-	-	-	-	-	-
871	Dist Load Dispatching	LB871	F007	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	LB872	F007	-	-	-	-	-	-
873	Compr. Station Fuel and Power	LB873	F007	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	LB874.01	CADAL	-	-	-	-	-	-
874.02	Leak Survey-Mains	LB874.02	F009	-	-	-	-	-	-
874.03	Leak Survey - Service	LB874.03	F010	-	-	-	-	-	-
874.04	Locate Main per Request	LB874.04	CADAL	-	-	-	-	-	-
874.05	Check Stop Box Access	LB874.05	F010	-	-	-	-	-	-
874.06	Patrolling Mains	LB874.06	F009	-	-	-	-	-	-
874.07	Check/Grease Valves	LB874.07	F009	-	-	-	-	-	-
874.08	Opr. Odor Equipment	LB874.08	F007	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	LB874.09	F009	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	LB874.10	F009	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	LB875	F008	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	LB876	F011	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	LB877	F008	-	-	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011	-	-	-	-	-	-
879	Customer Installation Expense	LB879	F011	-	-	-	-	-	-
880	Other Expenses	LB880	PTDSUB	-	-	-	-	-	-
881	Rents	LB881	PTDSUB	-					
Total Operations Distribution Labor		LBDO		$ -	$ -	$ -	$ -	$ -	$ -
Total Operations Transmission and Distribution Labor		LBTDO		$ -	$ -	$ -	$ -	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

	Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Labor Expenses (Continued)										
Maintenance Expense -- Transmission and Distribution										
885	Maintenance Supr and Engr	LB885	DMES	$ -	-	-	-	-	-	-
886	Maintenance Structures	LB886	F008	-	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009	81,259	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008	-	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	-	-	-	-	-	-
892	Maintenance Services	LB892	F010	-	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	18,717	-	-	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	5,703	-	-	-	-	-	135
898	Maintenance Transportaion Equip	LB898	PTDSUB	-	-	-	-	-	-	-
900	Trans & Distribution Expenses	LB900	TDSUB	2,692,246	-	-	980,432	-	-	40,415
	Total Maintenance Labor	LBDM		$ 2,797,925	$ -	$ -	$ 980,432	$ -	$ -	$ 40,549
	Total Transmission & Distribution Labor	LBTD		$ 2,926,397	$ -	$ -	$ 980,432	$ 128,472	$ -	$ 40,549
Customer Accounts Expense										
901	Supervision	LB901	F012	$ -	-	-	-	-	-	-
902	Meter Reading	LB902	F012	-	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012	$ 439,440	-	-	-	-	-	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-	-	-	-
	Total Customer Accounts Labor	LBCA		$ 439,440	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses										
907-910	Customer Service	LB907	F013	$ -	-	-	-	-	-	-
Sales Expenses										
911-916	Sales Expenses	LB911	F013	$ -	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)									
Maintenance Expense -- Transmission and Distribution									
885	Maintenance Supr and Engr	LB885	DMES	-	-	-	-	-	-
886	Maintenance Structures	LB886	F008	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009	26,986	54,273	-	-	-	-
888	Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	-	-	-	-	-
892	Maintenance Services	LB892	F010	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	18,717	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	1,259	2,532	777	1,000	-	-
898	Maintenance Transportaion Equip	LB898	PTDSUB	-	-	-	-	-	-
900	Trans & Distribution Expenses	LB900	TDSUB	377,896	760,001	233,261	300,241	-	-
Total Maintenance Labor		LBDM		$ 406,141	$ 816,806	$ 234,039	$ 319,958	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$ 406,141	$ 816,806	$ 234,039	$ 319,958	$ -	$ -
Customer Accounts Expense									
901	Supervision	LB901	F012	-	-	-	-	-	-
902	Meter Reading	LB902	F012	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012	-	-	-	-	439,440	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$ -	$ -	$ -	$ -	$ 439,440	$ -
Customer Service Expenses									
907-910	Customer Service	LB907	F013	-	-	-	-	-	-
Sales Expenses									
911-916	Sales Expenses	LB911	F013	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Labor Expenses (Continued)											
Administrative & General											
920	Admin and General Salaries	LB920	LBSUB	$	2,543,913	71,925	15,813	715,457	93,751	-	29,590
921	Office Supplies and Expense	LB921	LBSUB		-	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB		-	-	-	-	-	-	-
923	Outside Services Employed	LB923	OMSUB		-	-	-	-	-	-	-
924	Property Insurance	LB924	PTT		-	-	-	-	-	-	-
925	Injuries and Damages	LB925	PTT		-	-	-	-	-	-	-
926	Employee Pensions and Benefits	LB926	LBSUB		989,789	27,985	6,152	278,371	36,477	-	11,513
927	Franxhise Requirement	LB927	PTT		-	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT		-	-	-	-	-	-	-
929	Duplicate Charges -Dredit	LB929	PTT		-	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT		-	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	OMSUB		-	-	-	-	-	-	-
931	Rents	LB931	PTT		-	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389		-	-	-	-	-	-	-
Total Administrative and General Labor		LBAG		$	3,533,702	$ 99,910	$ 21,965	$ 993,829	$ 130,227	$ -	$ 41,104
Total Labor Expense		LBTOT		$	7,019,771	$ 198,473	$ 43,634	$ 1,974,261	$ 258,699	$ -	$ 81,653

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)									
Administrative & General									
920	Admin and General Salaries	LB920	LBSUB	296,376	596,054	170,787	233,485	320,675	-
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	-	-	-	-	-	-
923	Outside Services Employed	LB923	OMSUB	-	-	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-	-	-
925	Injuries and Damages	LB925	PTT	-	-	-	-	-	-
926	Employee Pensions and Benefits	LB926	LBSUB	115,314	231,913	66,450	90,845	124,769	-
927	Franxhise Requirement	LB927	PTT	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT	-	-	-	-	-	-
929	Duplicate Charges -Dredit	LB929	PTT	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	OMSUB	-	-	-	-	-	-
931	Rents	LB931	PTT	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389	-	-	-	-	-	-
Total Administrative and General Labor		LBAG		$ 411,690	$ 827,967	$ 237,236	$ 324,330	$ 445,444	$ -
Total Labor Expense		LBTOT		$ 817,831	$ 1,644,773	$ 471,275	$ 644,288	$ 884,884	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector		Total Company		Storage Demand		Storage Commodity		Transmission Demand		Transmission Commodity		Distribution Commodity		Distribution Structures & Equipment Demand
Operation & Maintenance Expenses																	
Production Expenses																	
Operation & Maintenance																	
753	Wells and Gathering	OM 753	F006		21,969		-		-		-		21,969		-		-
754	Compressor Station	OM754	F006		196,198		-		-		-		196,198		-		-
764	Maintenance of Wells and Gathering	OM764	F006		166		-		-		-		166		-		-
765	Maintenance of Compressor Station	OM765	F006		34,929		-		-		-		34,929		-		-
Total Production Operation & Maintenance Expenses					253,262		-		-		-		253,262		-		-
807-813	Procurement Expenses	OM807	DMCM	$	-		-		-		-		-		-		-
Storage Expenses																	
Operation																	
814	Operations Supervision and Engineer	OM814	OSE		-		-		-		-		-		-		-
815	Maps and Records	OM815	F003		-		-		-		-		-		-		-
816	Well Expenses	OM816	F003		109,451		109,451		-		-		-		-		-
817	Lines Expenses	OM817	F003		-		-		-		-		-		-		-
818	Compressor Station Exp - Payroll	OM818	F004		52,201		-		52,201		-		-		-		-
819	Compressor Station Fuel and Power	OM819	F004		-		-		-		-		-		-		-
820	Measurement and Regulator Station	OM820	F003		-		-		-		-		-		-		-
821	Purification of Natural Gas	OM821	F004		120,817		-		120,817		-		-		-		-
823	Gas losses	OM823	F004		867,900		-		867,900		-		-		-		-
824	Other Expenses	OM824	F004		27,005		-		27,005		-		-		-		-
825	Storage Well Royalities	OM825	F003		56,681		56,681		-		-		-		-		-
826	Rents	OM826	F003		-		-		-		-		-		-		-
Total Operation Expenses		OMOE		$	1,234,055	$	166,132	$	1,067,923	$	-	$	-	$	-	$	-
Storage Expense																	
Maintenance																	
830	Maintenance Super and Eng.	OM830	MSE	$	-		-		-		-		-		-		-
831	Maintenance of Structures	OM831	F003		5,844		5,844		-		-		-		-		-
832	Maintenance of Resevoirs	OM832	F003		613		613		-		-		-		-		-
833	Maintenance of Lines	OM833	F003		-		-		-		-		-		-		-
834	Main of Compressor Station Equipment	OM834	F004		12,355		-		12,355		-		-		-		-
835	Main of Meas and Reg Sta. Equip	OM835	F003		2,066		2,066		-		-		-		-		-
836	Main of Purification Equip	OM836	F004		-		-		-		-		-		-		-
837	Main of Other Equipment	OM837	F003		1,154		1,154		-		-		-		-		-
Total Maintenance Expense		OMME		$	22,033	$	9,678	$	12,355	$	-	$	-	$	-	$	-
Total Storage Expense		OMS		$	1,256,088		175,810		1,080,278		-		-		-		-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses									
Production Expenses									
Operation & Maintenance									
753	Wells and Gathering	OM 753	F006	-	-	-	-	-	-
754	Compressor Station	OM754	F006	-	-	-	-	-	-
764	Maintenance of Wells and Gathering	OM764	F006	-	-	-	-	-	-
765	Maintenance of Compressor Station	OM765	F006	-	-	-	-	-	-
Total Production Operation & Maintenance Expenses				-	-	-	-	-	-
807-813	Procurement Expenses	OM807	DMCM	-	-	-	-	-	-
Storage Expenses									
Operation									
814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-
815	Maps and Records	OM815	F003	-	-	-	-	-	-
816	Well Expenses	OM816	F003	-	-	-	-	-	-
817	Lines Expenses	OM817	F003	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004	-	-	-	-	-	-
819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-
820	Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-
821	Purification of Natural Gas	OM821	F004	-	-	-	-	-	-
823	Gas losses	OM823	F004	-	-	-	-	-	-
824	Other Expenses	OM824	F004	-	-	-	-	-	-
825	Storage Well Royalities	OM825	F003	-	-	-	-	-	-
826	Rents	OM826	F003	-	-	-	-	-	-
Total Operation Expenses		OMOE		$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense									
Maintenance									
830	Maintenance Super and Eng.	OM830	MSE	-	-	-	-	-	-
831	Maintenance of Structures	OM831	F003	-	-	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003	-	-	-	-	-	-
833	Maintenance of Lines	OM833	F003	-	-	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004	-	-	-	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003	-	-	-	-	-	-
836	Main of Purification Equip	OM836	F004	-	-	-	-	-	-
837	Main of Other Equipment	OM837	F003	-	-	-	-	-	-
Total Maintenance Expense		OMME		$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense		OMS		-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Operation & Maintenance Expenses (Continued)										
Transmission										
850-867	Transmission Expenses	OM850	F005	$ 121,438	-	-	121,438	-	-	-
Distribution Expenses										
Operation										
870	Operation Supr and Engr	OM870	DOES	$ -	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007	84,043	-	-	-	-	84,043	-
872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	-	-	-	-	-	-	-
874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009	-	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	-	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011	-	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB	359,498	-	-	-	-	-	8,488
881	Rents	OM881	PTDSUB	15,104	-	-	-	-	-	357
Total Operations Distribution Expense		OMDO		$ 458,645	-	-	-	-	84,043	8,844
Total Transmission and Distribution Oper Exp		OMTDO		$ 798,249	$ -	$ -	$ 121,438	$ 218,167	$ 84,043	$ 8,844

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)									
Transmission									
850-867	Transmission Expenses	OM850	F005	-	-	-	-	-	-
Distribution Expenses									
Operation									
870	Operation Supr and Engr	OM870	DOES	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	-	-	-	-	-	-
874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB	79,362	159,608	48,987	63,054	-	-
881	Rents	OM881	PTDSUB	3,334	6,706	2,058	2,649	-	-
Total Operations Distribution Expense		OMDO		82,696	166,314	51,045	65,703	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 82,696	$ 166,314	$ 51,045	$ 65,703	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Operation & Maintenance Expenses (Continued)											
Maintenance Expense -- Transmission and Distribution											
885	Maintenance Supr and Engr	OM885	DMES	$	-	-	-	-	-	-	-
886	Maintenance Structures	OM886	F008		-	-	-	-	-	-	-
887	Maintenance Mains	OM887	F009		157,799	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007		-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008		2,221	-	-	-	-	-	2,221
890	Maintenance Meas and Reg - Industrial	OM890	F011		-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008		-	-	-	-	-	-	-
892	Maintenance Services	OM892	F010		-	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011		57,773	-	-	-	-	-	-
894	Maintenance Other Equipment	OM894	PTDSUB		130,203	-	-	-	-	-	3,074
898	Maintenance Transportaion Equip	OM898	PTDSUB		42,119	-	-	-	-	-	994
900	Trans & Distribution Expenses	OM900	TDSUB		3,530,029	-	-	1,285,526	-	-	52,991
Total Maintenance Expenses		OMME		$	3,920,144	$ -	$ -	$ 1,285,526	$ -	$ -	$ 59,281
Total Transmission & Distribution Expenses		OMDE		$	4,753,488	$ -	$ -	$ 1,406,965	$ 253,262	$ 84,043	$ 68,125
Customer Accounts Expense											
901	Supervision	OM901	F012	$	-	-	-	-	-	-	-
902	Meter Reading	OM902	F012		-	-	-	-	-	-	-
903	Customer Records and Collections	OM903	F012	$	778,501	-	-	-	-	-	-
904	Uncollectible Accounts	OM904	F012		(185,412)	-	-	-	-	-	-
905	Misc. Cust Account Expenses	OM905	F012		-	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$	593,089	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses											
907-910	Customer Service	OM907	F013	$	-	-	-	-	-	-	-
Sales Expenses											
911-916	Sales Expenses	OM911	F013	$	1,438	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)									
Maintenance Expense -- Transmission and Distribution									
885	Maintenance Supr and Engr	OM885	DMES	-	-	-	-	-	-
886	Maintenance Structures	OM886	F008	-	-	-	-	-	-
887	Maintenance Mains	OM887	F009	52,405	105,394	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008	-	-	-	-	-	-
892	Maintenance Services	OM892	F010	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011	-	-	-	57,773	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	28,743	57,807	17,742	22,837	-	-
898	Maintenance Transportaion Equip	OM898	PTDSUB	9,298	18,700	5,739	7,387	-	-
900	Trans & Distribution Expenses	OM900	TDSUB	495,490	996,501	305,849	393,671	-	-
Total Maintenance Expenses		OMME		$ 585,937	$ 1,178,402	$ 329,330	$ 481,668	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$ 668,633	$ 1,344,715	$ 380,376	$ 547,371	$ -	$ -
Customer Accounts Expense									
901	Supervision	OM901	F012	-	-	-	-	-	-
902	Meter Reading	OM902	F012	-	-	-	-	-	-
903	Customer Records and Collections	OM903	F012	-	-	-	-	778,501	-
904	Uncollectible Accounts	OM904	F012	-	-	-	-	(185,412)	-
905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$ -	$ -	$ -	$ -	$ 593,089	$ -
Customer Service Expenses									
907-910	Customer Service	OM907	F013	-	-	-	-	-	-
Sales Expenses									
911-916	Sales Expenses	OM911	F013	-	-	-	-	-	1,438

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector		Total Company		Storage Demand		Storage Commodity		Transmission Demand		Transmission Commodity		Distribution Commodity		Distribution Structures & Equipment Demand
Operation & Maintenance Expenses (Continued)																	
Administrative & General																	
920	Admin and General Salaries	OM920	LBSUB	$	2,628,513		74,317		16,339		739,251		96,869		-		30,575
921	Office Supplies and Expense	OM921	LBSUB		549,130		15,526		3,413		154,439		20,237		-		6,387
922	Admin. Expenses Transferred	OM922	LBSUB		(3,314,076)		(93,700)		(20,600)		(932,060)		(122,134)		-		(38,549)
923	Outside Services Employed	OM923	OMSUB		1,085,160		28,888		177,507		231,187		41,615		13,810		11,194
924	Property Insurance	OM924	PTT		846,315		89,307		-		275,888		-		-		11,363
925	Injuries and Damages	OM925	PTT		-		-		-		-		-		-		-
926	Employee Pensions and Benefits	OM926	LBSUB		3,978,940		112,498		24,733		1,119,049		146,636		-		46,282
927	Franchise Requirement	OM927	PTT		-		-		-		-		-		-		-
928	Regulatory Commission Fee	OM928	PTT		189,509		19,998		-		61,778		-		-		2,544
929	Duplicate Charges -Dredit	OM929	PTT		-		-		-		-		-		-		-
930.1	General Advertising Expense	OM930.1	PTT		-		-		-		-		-		-		-
930.2	Misc. General Expense	OM930.2	OMSUB		559,375		14,891		91,501		119,172		21,452		7,119		5,770
931	Rents	OM931	PTT		-		-		-		-		-		-		-
932	Maintenance of General Plant	OM932	PT389		197,811		17,060		-		65,824		-		-		2,713
Total Administrative and General Expense		OMAGT		$	6,720,678	$	278,786	$	292,892	$	1,834,526	$	204,674	$	20,928	$	78,280
Total Operation & Maintenance Expense		OMT		$	13,324,781	$	454,596	$	1,373,171	$	3,241,491	$	457,936	$	104,971	$	146,405

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)									
Administrative & General									
920	Admin and General Salaries	OM920	LBSUB	306,232	615,876	176,466	241,250	331,340	-
921	Office Supplies and Expense	OM921	LBSUB	63,976	128,664	36,866	50,400	69,221	-
922	Admin. Expenses Transferred	OM922	LBSUB	(386,103)	(776,507)	(222,492)	(304,172)	(417,759)	-
923	Outside Services Employed	OM923	OMSUB	109,867	220,958	62,502	89,942	97,454	236
924	Property Insurance	OM924	PTT	106,193	213,568	65,582	84,414	-	-
925	Injuries and Damages	OM925	PTT	-	-	-	-	-	-
926	Employee Pensions and Benefits	OM926	LBSUB	463,562	932,289	267,128	365,195	501,569	-
927	Franchise Requirement	OM927	PTT	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	23,779	47,823	14,685	18,902	-	-
929	Duplicate Charges -Dredit	OM929	PTT	-	-	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB	56,634	113,899	32,218	46,363	50,235	122
931	Rents	OM931	PTT	-	-	-	-	-	-
932	Maintenance of General Plant	OM932	PT389	25,371	51,025	15,661	20,157	-	-
Total Administrative and General Expense		OMAGT		$ 769,511	$ 1,547,594	$ 448,617	$ 612,451	$ 632,060	$ 358
Total Operation & Maintenance Expense		OMT		$ 1,438,144	$ 2,892,310	$ 828,992	$ 1,159,822	$ 1,225,149	$ 1,796

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Depreciation Expenses											
Underground Storage											
350-357	Underground Storage Plant	DP350	F003	$	293,733	293,733	-	-	-	-	-
Transmission											
365-371	Transmission Plant	DP365	F005	$	1,232,318	-	-	1,232,318	-	-	-
Distribution											
374	Land & Land Rights	DP374	F008	$	-	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008		3,000	-	-	-	-	-	3,000
376	Mains	DP376	F009		926,374	-	-	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008		45,914	-	-	-	-	-	45,914
379	Meas & Reg Station Eq.-City Gate	DP379	F008		14,674	-	-	-	-	-	14,674
380	Services	DP380	F010		191,190	-	-	-	-	-	-
381	Meters	DP381	F011		211,954	-	-	-	-	-	-
382	Meter Installations	DP382	F011		74,194	-	-	-	-	-	-
383	House Regulators	DP383	F011		130,944	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011		-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011		36,370	-	-	-	-	-	-
387	Other Equipment	DP387	F011		-	-	-	-	-	-	-
	Other		PTSUB		-	-	-	-	-	-	-
Total Distribution				$	1,634,615	$ -	$ -	$ -	$ -	$ -	$ 63,588
117	Gas Stored Underground	DP117	F003	$	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB		-	-	-	-	-	-	-
389-399	General Plant	DP389	PTSUB		651,391	56,179	-	216,758	-	-	8,935
Common Utility Plant		DPCP	PTSUB		-	-	-	-	-	-	-
Amortization of Gas Plant		AMORT	PTSUB		(19,800)	(1,708)	-	(6,589)	-	-	(272)
Accretion Expense		ACCRTN	PTSUB		-	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$	3,792,258	$ 348,204	$ -	$ 1,442,487	$ -	$ -	$ 72,251

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Depreciation Expenses									
Underground Storage									
350-357	Underground Storage Plant	DP350	F003	-	-	-	-	-	-
Transmission									
365-371	Transmission Plant	DP365	F005	-	-	-	-	-	-
Distribution									
374	Land & Land Rights	DP374	F008	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008	-	-	-	-	-	-
376	Mains	DP376	F009	307,649	618,725	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	-	-	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	-	-	-	-	-	-
380	Services	DP380	F010	-	-	191,190	-	-	-
381	Meters	DP381	F011	-	-	-	211,954	-	-
382	Meter Installations	DP382	F011	-	-	-	74,194	-	-
383	House Regulators	DP383	F011	-	-	-	130,944	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	-	-	-	36,370	-	-
387	Other Equipment	DP387	F011	-	-	-	-	-	-
	Other		PTSUB	-	-	-	-	-	-
Total Distribution				$ 307,649	$ 618,725	$ 191,190	$ 453,463	$ -	$ -
117	Gas Stored Underground	DP117	F003	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	-	-	-	-	-	-
389-399	General Plant	DP389	PTSUB	83,547	168,024	51,570	66,378	-	-
Common Utility Plant		DPCP	PTSUB	-	-	-	-	-	-
Amortization of Gas Plant		AMORT	PTSUB	(2,540)	(5,107)	(1,568)	(2,018)	-	-
Accretion Expense		ACCRTN	PTSUB	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$ 388,656	$ 781,642	$ 241,193	$ 517,824	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Taxes Other Than Income Taxes										
Liscense & Privilege Fee	OTRE	PTT	$	7,382	779	-	2,407	-	-	99
Property Taxes	OTPP	PTT		1,320,467	139,342	-	430,456	-	-	17,729
Payroll Taxes	OTUN	LBTOT		577,030	16,315	3,587	162,286	21,265	-	6,712
Total Taxes Other Than Income Taxes	OTT		$	1,904,879 $	156,435 $	3,587 $	595,148 $	21,265 $	- $	24,540
Interest on Long Term Debt	INT	PTT	$	4,075,601	430,076	-	1,328,596	-	-	54,720

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Taxes Other Than Income Taxes								
Liscense & Privilege Fee	OTRE	PTT	926	1,863	572	736	-	-
Property Taxes	OTPP	PTT	165,687	333,221	102,325	131,707	-	-
Payroll Taxes	OTUN	LBTOT	67,226	135,202	38,739	52,961	72,738	-
Total Taxes Other Than Income Taxes	OTT		$ 233,840	$ 470,285	$ 141,636	$ 185,405	$ 72,738	$ -
Interest on Long Term Debt	INT	PTT	511,391	1,028,480	315,825	406,513	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Functional Assignment Vectors									
Gas Supply Demand	F001		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Distribution Expense Commodity	F007		1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Distribution Structures & Equipment	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Distribution Mains	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Accounts	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F013		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission & Distribution Mains	TDMSUB		$ 124,496,316	$ -	$ -	$ 57,620,977	$ -	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Functional Assignment Vectors								
Gas Supply Demand	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Expense Commodity	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Structures & Equipment	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Mains	F009		0.332100	0.667900	0.000000	0.000000	0.000000	0.000000
Services	F010		0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Meters	F011		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Customer Accounts	F012		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Customer Service Expense	F013		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Transmission & Distribution Mains	TDMSUB		$ 22,209,300	$ 44,666,039	$ -	$ -	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector		Total Company		Storage Demand		Storage Commodity		Transmission Demand		Transmission Commodity		Distribution Commodity		Distribution Structures & Equipment Demand
Internally Generated Functional Vectors																
Sub-Total Distribution Plant		PTDSUB		1.000000		-		-		-		-		-		0.023609
Storage-Transmission-Distribution Subtotal		PTSUB		1.000000		0.086244		-		0.332761		-		-		0.013717
Total Storage Plant		PTST		1.000000		1.000000		-		-		-		-		-
Transmission Plant		PT365		1.000000		-		-		1.000000		-		-		-
General Plant		PT389		1.000000		0.086244		-		0.332761		-		-		0.013717
Total Distribution Plant		PTDSUB		1.000000		-		-		-		-		-		0.023609
Sub-Total CWIP		CWIP		1.000000		0.075939		-		0.434755		-		-		0.013367
Total Depreciation Reserve		DEPR		1.000000		0.086267		-		0.342843		-		-		0.013478
Storage-Transmission -Distribution Plant Subtotal		PTSUB		1.000000		0.086244		-		0.332761		-		-		0.013717
Transmission and Distribution Payroll		LBTD		1.000000		-		-		0.335030		0.043901		-		0.013856
Transmission and Distribution Mains		TDMSUB		1.000000		-		-		0.462833		-		-		-
Storage Operation Expenses Subtotal	OSE			117,698		97,523		20,175		-		-		-		-
Storage Maintenance Expenses Subtotal	MSE			2,534		1,040		1,494		-		-		-		-
Mains & Services	CADAL			80,584,347		-		-		-		-		-		-
Demand/Commodity Percent of Purchased Gas Cost	DMCM			1.00000												
Distribution Operation Expenses Subtotal	DOES			-		-		-		-		-		-		-
Distribution Maintenance Expenses Subtotal	DMES			105,679		-		-		-		-		-		135
Subtotal Labor Expenses	LBSUB		$	3,486,069	$	98,563	$	21,669	$	980,432	$	128,472	$	-	$	40,549
Subtotal O&M Expenses	OMSUB		$	6,604,104	$	175,810	$	1,080,278	$	1,406,965	$	253,262	$	84,043	$	68,125

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
<u>Internally Generated Functional Vectors</u>								
Sub-Total Distribution Plant		PTDSUB	0.220757	0.443974	0.136266	0.175393	-	-
Storage-Transmission-Distribution Subtotal		PTSUB	0.128259	0.257946	0.079170	0.101903	-	-
Total Storage Plant		PTST	-	-	-	-	-	-
Transmission Plant		PT365	-	-	-	-	-	-
General Plant		PT389	0.128259	0.257946	0.079170	0.101903	-	-
Total Distribution Plant		PTDSUB	0.220757	0.443974	0.136266	0.175393	-	-
Sub-Total CWIP		CWIP	0.099459	0.200026	0.077151	0.099304	-	-
Total Depreciation Reserve		DEPR	0.126028	0.253461	0.077793	0.100130	-	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	0.128259	0.257946	0.079170	0.101903	-	-
Transmission and Distribution Payroll		LBTD	0.138785	0.279117	0.079975	0.109335	-	-
Transmission and Distribution Mains		TDMSUB	0.178393	0.358774	-	-	-	-
Storage Operation Expenses Subtotal	OSE		-	-	-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		-	-	-	-	-	-
Mains & Services	CADAL		22,209,300	44,666,039	13,709,009	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM							
Distribution Operation Expenses Subtotal	DOES		-	-	-	-	-	-
Distribution Maintenance Expenses Subtotal	DMES		28,245	56,805	777	19,717	-	-
Subtotal Labor Expenses	LBSUB		$ 406,141	$ 816,806	$ 234,039	$ 319,958	$ 439,440	$ -
Subtotal O&M Expenses	OMSUB		$ 668,633	$ 1,344,715	$ 380,376	$ 547,371	$ 593,089	$ 1,438

Seelye Exhibit 6

Class Cost of Service Study

Allocation of Costs by
Rate Class

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Plant in Service (Continued)																	
Distribution Mains																	
Demand	PTIS	PTISDMD	DEM05	$	24,940,653	$	11,308,407	$	3,718,577	$	8,103,281	$	1,722,368	$	88,020	$	-
Customer	PTIS	PTISDMC	CUST01		50,159,175	$	42,800,385	$	5,963,396	$	1,337,078	$	56,926	$	1,388	$	-
Total Distribution Mains					75,099,828	$	54,108,792	$	9,681,973	$	9,440,359	$	1,779,295	$	89,409	$	-
Services																	
Customer	PTIS	PTISSC	CUST02	$	15,394,975	$	12,679,380	$	1,646,099	$	1,022,766	$	43,545	$	3,186	$	-
Meters																	
Customer	PTIS	PTISMC	CUST03	$	19,815,542	$	13,355,472	$	2,990,345	$	3,046,528	$	378,581	$	44,616	$	-
Customer Accounts																	
Customer	PTIS	PTISCAC	CUST04	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service																	
Customer	PTIS	PTISCSC	CUST05	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Total		PLT		$	198,663,799	$	108,094,752	$	23,520,966	$	34,112,662	$	4,940,043	$	4,498,739	$	23,496,637

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Rate Base										
Gas Supply Costs										
Demand	NCRB	RBGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	NCRB	RBGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	NCRB	RBSD	DEM02	$ 16,737,875	$ 7,954,835	$ 2,624,831	$ 6,158,209	$ -	$ -	$ -
Commodity	NCRB	RBSC	COM02	170,895	$ 77,028	$ 26,273	$ 67,594	$ -	$ -	$ -
Total Storage				$ 16,908,770	$ 8,031,863	$ 2,651,104	$ 6,225,803	$ -	$ -	$ -
Transmission										
Demand	NCRB	RBTD	TDEM	$ 33,323,606	$ 8,637,065	$ 2,840,151	$ 6,189,074	$ 1,315,500	$ 2,241,294	$ 12,100,523
Commodity	NCRB	RBTC	COM03	56,991	$ 5,294	$ 1,775	$ 6,103	$ 3,445	$ 6,266	$ 34,109
Total Transmission				$ 33,380,598	$ 8,642,359	$ 2,841,926	$ 6,195,177	$ 1,318,945	$ 2,247,559	$ 12,134,632
Distribution Expenses										
Commodity	NCRB	RBDEC	COM04	$ 13,064	$ 4,115	$ 1,380	$ 4,744	$ 2,678	$ 147	$ -
Distribution Structures & Equipment										
Demand	NCRB	RBDSD	DEM04	$ 1,419,548	$ 643,641	$ 211,650	$ 461,215	$ 98,032	$ 5,010	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Rate Base (Continued)										
Distribution Mains										
Demand	NCRB	RBDMD	DEM05	$ 13,254,121	$ 6,009,586	$ 1,976,150	$ 4,306,297	$ 915,312	$ 46,776	$ -
Customer	NCRB	RBDMC	CUST01	26,655,910	$ 22,745,255	$ 3,169,106	$ 710,559	$ 30,252	$ 738	$ -
Total Distribution Mains				39,910,031	$ 28,754,841	$ 5,145,256	$ 5,016,856	$ 945,564	$ 47,514	$ -
Services										
Customer	NCRB	RBSC	CUST02	$ 8,181,893	$ 6,738,649	$ 874,844	$ 543,564	$ 23,142	$ 1,693	$ -
Meters										
Customer	NCRB	RBMC	CUST03	$ 10,554,775	$ 7,113,810	$ 1,592,811	$ 1,622,737	$ 201,652	$ 23,765	$ -
Customer Accounts										
Customer	NCRB	RBCAC	CUST04	$ 152,473	$ 119,847	$ 16,547	$ 14,954	$ 594	$ 63	$ 469
Customer Service										
Customer	NCRB	RBCSC	CUST05	$ 224	$ 191	$ 26	$ 6	$ 0	$ 0	$ -
Total		RBT		$ 110,521,375	$ 60,049,315	$ 13,335,545	$ 20,085,056	$ 2,590,607	$ 2,325,751	$ 12,135,101

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Operation and Maintenance Expenses										
Gas Supply Costs										
Demand	OMT	OMGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	OMT	OMGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		OMGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	OMT	OMSD	DEM02	$ 454,596	$ 216,051	$ 71,290	$ 167,255	$ -	$ -	$ -
Commodity	OMT	OMSC	COM02	1,373,171	$ 618,932	$ 211,108	$ 543,131	$ -	$ -	$ -
Total Storage		OMST		$ 1,827,766	$ 834,983	$ 282,397	$ 710,386	$ -	$ -	$ -
Transmission										
Demand	OMT	OMTD	TDEM	$ 3,241,491	$ 840,154	$ 276,270	$ 602,030	$ 127,963	$ 218,018	$ 1,177,055
Commodity	OMT	OMTC	COM03	457,936	$ 42,536	$ 14,261	$ 49,041	$ 27,679	$ 50,345	$ 274,074
Total Transmission		OMTRT		$ 3,699,427	$ 882,690	$ 290,531	$ 651,071	$ 155,642	$ 268,362	$ 1,451,129
Distribution Expenses										
Commodity	OMT	OMDEC	COM04	$ 104,971	$ 33,064	$ 11,085	$ 38,121	$ 21,516	$ 1,184	$ -
Distribution Structures & Equipment										
Demand	OMT	OMDSD	DEM04	$ 146,405	$ 66,382	$ 21,829	$ 47,567	$ 10,111	$ 517	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Operation and Maintenance Expenses (Continued)																	
Distribution Mains																	
Demand	OMT	OMDMD	DEM05	$	1,438,144	$	652,072	$	214,423	$	467,256	$	99,316	$	5,075	$	-
Customer	OMT	OMDMC	CUST01		2,892,310	$	2,467,983	$	343,865	$	77,099	$	3,283	$	80	$	-
Total Distribution Mains					4,330,453	$	3,120,055	$	558,288	$	544,356	$	102,599	$	5,156	$	-
Services																	
Customer	OMT	OMSC	CUST02	$	828,992	$	682,762	$	88,640	$	55,074	$	2,345	$	172	$	-
Meters																	
Customer	OMT	OMMC	CUST03	$	1,159,822	$	781,708	$	175,028	$	178,316	$	22,159	$	2,611	$	-
Customer Accounts																	
Customer	OMT	OMCAC	CUST04	$	1,225,149	$	962,994	$	132,961	$	120,155	$	4,771	$	502	$	3,767
Customer Service																	
Customer	OMT	OMCSC	CUST05	$	1,796	$	1,534	$	212	$	48	$	2	$	0	$	-
Total		OMTT		$	13,324,781	$	7,366,173	$	1,560,971	$	2,345,094	$	319,144	$	278,504	$	1,454,896

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Payroll Expenses																	
Distribution Mains																	
Demand	LBTOT	LBDMD	DEM05	$	817,831	$	370,815	$	121,936	$	265,715	$	56,478	$	2,886	$	-
Customer	LBTOT	LBDMC	CUST01		1,644,773	$	1,403,470	$	195,546	$	43,844	$	1,867	$	46	$	-
Total Distribution Mains					2,462,604	$	1,774,285	$	317,482	$	309,559	$	58,345	$	2,932	$	-
Services																	
Customer	LBTOT	LBSC	CUST02	$	471,275	$	388,144	$	50,391	$	31,309	$	1,333	$	98	$	-
Meters																	
Customer	LBTOT	LBMC	CUST03	$	644,288	$	434,244	$	97,229	$	99,056	$	12,309	$	1,451	$	-
Customer Accounts																	
Customer	LBTOT	LBCAC	CUST04	$	884,884	$	695,538	$	96,033	$	86,784	$	3,446	$	363	$	2,720
Customer Service																	
Customer	LBTOT	LBCSC	CUST05	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Total		LBTT		$	7,019,771	$	3,978,961	$	787,464	$	1,037,895	$	174,646	$	166,358	$	874,448

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Depreciation Expenses																	
Gas Supply Costs																	
Demand	DEPREX	DEGSD	DEM01	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Commodity	DEPREX	DEGSC	COM01		-	$	-	$	-	$	-	$	-	$	-	$	-
Total Procurement Expenses		DEGST		$	-	$	-	$	-	$	-	$	-	$	-	$	-
Storage																	
Demand	DEPREX	DESD	DEM02	$	348,204	$	165,487	$	54,605	$	128,111	$	-	$	-	$	-
Commodity	DEPREX	DESC	COM02		-	$	-	$	-	$	-	$	-	$	-	$	-
Total Storage		DEST		$	348,204	$	165,487	$	54,605	$	128,111	$	-	$	-	$	-
Transmission																	
Demand	DEPREX	DETD	TDEM	$	1,442,487	$	373,875	$	122,942	$	267,908	$	56,944	$	97,019	$	523,798
Commodity	DEPREX	DETC	COM03		-	$	-	$	-	$	-	$	-	$	-	$	-
Total Transmission		DETT		$	1,442,487	$	373,875	$	122,942	$	267,908	$	56,944	$	97,019	$	523,798
Distribution Expenses																	
Commodity	DEPREX	DEDEC	COM04	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Structures & Equipment																	
Demand	DEPREX	DEDSD	DEM04	$	72,251	$	32,760	$	10,772	$	23,475	$	4,990	$	255	$	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Depreciation Expenses (Continued)																	
Distribution Mains																	
Demand	DEPREX	DEDMD	DEM05	$	388,656	$	176,221	$	57,947	$	126,275	$	26,840	$	1,372	$	-
Customer	DEPREX	DEDMC	CUST01		781,642	$	666,968	$	92,929	$	20,836	$	887	$	22	$	-
Total Distribution Mains					1,170,298	$	843,190	$	150,876	$	147,111	$	27,727	$	1,393	$	-
Services																	
Customer	DEPREX	DESC	CUST02	$	241,193	$	198,648	$	25,789	$	16,024	$	682	$	50	$	-
Meters																	
Customer	DEPREX	DEMC	CUST03	$	517,824	$	349,008	$	78,144	$	79,612	$	9,893	$	1,166	$	-
Customer Accounts																	
Customer	DEPREX	DECAC	CUST04	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service																	
Customer	DEPREX	DECSC	CUST05	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Total		DET		$	3,792,258	$	1,962,967	$	443,130	$	662,242	$	100,236	$	99,884	$	523,798

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Other Taxes																	
Gas Supply Costs																	
Demand	OTT	OTTGSD	DEM01	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Commodity	OTT	OTTGSC	COM01		-	$	-	$	-	$	-	$	-	$	-	$	-
Total Procurement Expenses		OTTGST		$	-	$	-	$	-	$	-	$	-	$	-	$	-
Storage																	
Demand	OTT	OTTSD	DEM02	$	156,435	$	74,347	$	24,532	$	57,556	$	-	$	-	$	-
Commodity	OTT	OTTSC	COM02		3,587	$	1,617	$	551	$	1,419	$	-	$	-	$	-
Total Storage		OTTST		$	160,022	$	75,964	$	25,084	$	58,974	$	-	$	-	$	-
Transmission																	
Demand	OTT	OTTTD	TDEM	$	595,148	$	154,255	$	50,724	$	110,535	$	23,494	$	40,029	$	216,111
Commodity	OTT	OTTTC	COM03		21,265	$	1,975	$	662	$	2,277	$	1,285	$	2,338	$	12,727
Total Transmission		OTTTT		$	616,413	$	156,230	$	51,386	$	112,812	$	24,780	$	42,367	$	228,838
Distribution Expenses																	
Commodity	OTT	OTTDEC	COM04	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Structures & Equipment																	
Demand	OTT	OTTDSD	DEM04	$	24,540	$	11,127	$	3,659	$	7,973	$	1,695	$	87	$	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Other Taxes (Continued)																	
Distribution Mains																	
Demand	OTT	OTTDMD	DEM05	$	233,840	$	106,026	$	34,865	$	75,975	$	16,149	$	825	$	-
Customer	OTT	OTTDMC	CUST01		470,285	$	401,290	$	55,912	$	12,536	$	534	$	13	$	-
Total Distribution Mains					704,125	$	507,316	$	90,777	$	88,511	$	16,682	$	838	$	-
Services																	
Customer	OTT	OTTSC	CUST02	$	141,636	$	116,653	$	15,144	$	9,410	$	401	$	29	$	-
Meters																	
Customer	OTT	OTTMC	CUST03	$	185,405	$	124,961	$	27,979	$	28,505	$	3,542	$	417	$	-
Customer Accounts																	
Customer	OTT	OTTCAC	CUST04	$	72,738	$	57,174	$	7,894	$	7,134	$	283	$	30	$	224
Customer Service																	
Customer	OTT	OTTCSC	CUST05	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Total		OTTT		$	1,904,879	$	1,049,424	$	221,923	$	313,319	$	47,383	$	43,768	$	229,062

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Interest Expense										
Gas Supply Costs										
Demand	INT	INTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	INT	INTGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		INTGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	INT	INTSD	DEM02	$ 430,076	$ 204,398	$ 67,445	$ 158,234	$ -	$ -	$ -
Commodity	INT	INTSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage		INTST		$ 430,076	$ 204,398	$ 67,445	$ 158,234	$ -	$ -	$ -
Transmission										
Demand	INT	INTTD	TDEM	$ 1,328,596	$ 344,355	$ 113,235	$ 246,755	$ 52,448	$ 89,359	$ 482,442
Commodity	INT	INTTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission		INTTT		$ 1,328,596	$ 344,355	$ 113,235	$ 246,755	$ 52,448	$ 89,359	$ 482,442
Distribution Expenses										
Commodity	INT	INTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	INT	INTDSD	DEM04	$ 54,720	$ 24,811	$ 8,159	$ 17,779	$ 3,779	$ 193	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<u>Interest Expense (Continued)</u>										
Distribution Mains										
Demand	INT	INTDMD	DEM05	$ 511,391	$ 231,871	$ 76,247	$ 166,152	$ 35,316	$ 1,805	$ -
Customer	INT	INTDMC	CUST01	1,028,480	$ 877,593	$ 122,275	$ 27,416	$ 1,167	$ 28	$ -
Total Distribution Mains				1,539,871	$ 1,109,464	$ 198,522	$ 193,568	$ 36,483	$ 1,833	$ -
Services										
Customer	INT	INTSC	CUST02	$ 315,825	$ 260,115	$ 33,769	$ 20,982	$ 893	$ 65	$ -
Meters										
Customer	INT	INTMC	CUST03	$ 406,513	$ 273,985	$ 61,346	$ 62,499	$ 7,767	$ 915	$ -
Customer Accounts										
Customer	INT	INTCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	INT	INTCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 4,075,601	$ 2,217,129	$ 482,477	$ 699,817	$ 101,370	$ 92,366	$ 482,442

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Net Operating Income -- Adjusted Test Period																	
Operating Revenues																	
Sales and Transportation	REVUC	R01			27,769,025		12,622,626		3,598,374		6,338,627		1,484,067		309,428		3,415,904
Collection Fees	COLFEE	COLL		$	177,360	$	157,980	$	1,641	$	17,740	$	-	$	-	$	-
Reconnect Revenue	RCTREV	RCNCT			111,420	$	92,100	$	1,680	$	17,640	$	-	$	-	$	-
Bad Check Revenue	BDCH	BDCK			13,800	$	11,895	$	225	$	1,680	$	-	$	-	$	-
Total Operating Revenues -- Per Books	TOR			$	28,071,605	$	12,884,600	$	3,601,920	$	6,375,687	$	1,484,067	$	309,428	$	3,415,904
Pro-Forma Adjustments to Revenues																	
Temperature normalization	REVADJ1			$	(63,111)	$	(57,963)	$	(13,206)	$	8,004	$	53	$	-	$	-
Total Revenue Adjustments				$	(63,111)	$	(57,963)	$	(13,206)	$	8,004	$	53	$	-	$	-
Total Adjusted Revenue				$	28,008,494	$	12,826,638	$	3,588,714	$	6,383,691	$	1,484,120	$	309,428	$	3,415,904
Expenses																	
Operation and Maintenance Expenses				$	13,324,781	$	7,366,173	$	1,560,971	$	2,345,094	$	319,144	$	278,504	$	1,454,896
Depreciation and Amortization Expenses				$	3,792,258		1,962,967		443,130		662,242		100,236		99,884		523,798
Other Taxes				$	1,904,879		1,049,424		221,923		313,319		47,383		43,768		229,062
Total Operating Expenses	TOE			$	19,021,918	$	10,378,564	$	2,226,024	$	3,320,655	$	466,763	$	422,156	$	2,207,756

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted Test Period (Cont.)										
Pro-Forma Adjustments to Expenses										
Labor Adjustment		EXADJ1	LBTT	$ (41,046)	$ (23,266)	$ (4,604)	$ (6,069)	$ (1,021)	$ (973)	$ (5,113)
Eliminate Advedrtising Expenses		EXADJ2	OTTT	(1,438)	$ (792)	$ (168)	$ (237)	$ (36)	$ (33)	$ (173)
Lobbying Expense		EXADJ3	OTTT	(19,194)	$ (10,574)	$ (2,236)	$ (3,157)	$ (477)	$ (441)	$ (2,308)
Community Relations		EXADJ4	OTTT	(26,450)	$ (14,572)	$ (3,081)	$ (4,351)	$ (658)	$ (608)	$ (3,181)
Marketing		EXADJ5	OMTT	(1,944)	$ (1,075)	$ (228)	$ (342)	$ (47)	$ (41)	$ (212)
Rate Case Expenses		EXADJ6	OMTT	(10,948)	$ (6,052)	$ (1,283)	$ (1,927)	$ (262)	$ (229)	$ (1,195)
Depreciation Expenses		EXADJ7	DET	1,311,714	$ 678,976	$ 153,275	$ 229,064	$ 34,671	$ 34,549	$ 181,178
Bad Debt Expenses		EXADJ7	BDCK	330,993	$ 285,303	$ 5,395	$ 40,295	$ -	$ -	$ -
Conservation		EXADJ8	REVUC	(600)	$ (273)	$ (78)	$ (137)	$ (32)	$ (7)	$ (74)
Property Tax		EXADJ9	OTTT	67,835	$ 37,371	$ 7,903	$ 11,158	$ 1,687	$ 1,559	$ 8,157
		EXADJ10	INTT	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Expense Adjustments		ADJTOT		$ 1,608,922	$ 945,046	$ 154,896	$ 264,298	$ 33,825	$ 33,777	$ 177,079
Net Income Before Income Taxes				$ 7,377,653	$ 1,503,027	$ 1,207,794	$ 2,798,738	$ 983,531	$ (146,505)	$ 1,031,069
Income Taxes			TXINC	$ 2,081,177	$ (565,631)	$ 472,454	$ 1,393,200	$ 592,741	$ (164,901)	$ 353,314
Net Operating Income (Adjusted)		TOM		$ 5,296,476	$ 2,068,658	$ 735,340	$ 1,405,538	$ 390,791	$ 18,395	$ 677,755
Net Cost Rate Base				$ 110,521,375	$ 60,049,315	$ 13,335,545	$ 20,085,056	$ 2,590,607	$ 2,325,751	$ 12,135,101
Rate of Return -- Actual				4.79%	3.44%	5.51%	7.00%	15.08%	0.79%	5.59%

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted For Increase										
Test Year Operating Income				$ 5,296,476	$ 2,068,658	$ 735,340	$ 1,405,538	$ 390,791	$ 18,395	$ 677,755
Proposed Increase				$ 5,315,428	$ 3,541,111	611,533	$ 909,754	$ -	$ -	$ 253,030
Increase To Misc Revenue			RCNCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Increase		CLSINC		$ 5,315,428	$ 3,541,111	$ 611,533	$ 909,754	$ -	$ -	$ 253,030
Incremental Income Taxes (@39.4445)			CLSINC	1,036,917	$ 690,789	$ 119,296	$ 177,472	$ -	$ -	$ 49,360
Net Operating Income Adjusted for Increase				9,574,987	4,918,980	1,227,577	2,137,820	390,791	18,395	881,425
Net Cost Rate Base				$ 110,521,375	$ 60,049,315	$ 13,335,545	$ 20,085,056	$ 2,590,607	$ 2,325,751	$ 12,135,101
Rate of Return -- Proposed				8.66%	8.19%	9.21%	10.64%	15.08%	0.79%	7.26%

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Allocation Factors			$	3,118,094						
				3079555 $	38,539					
Commodity										
Procurement Expenses		COM01		17,782,734	1,651,781	553,791	1,904,373	1,074,852	1,955,008	10,642,929
					0.092887	0.031142	0.107091			
Storage (Dec thru March)		COM02		2,511,065	1,131,817	386,045	993,203	-	-	-
Transmission		COM03		17,782,734	1,651,781	553,791	1,904,373	1,074,852	1,955,008	10,642,929
Distribution		COM04		5,243,952	1,651,781	553,791	1,904,373	1,074,852	59,155	-
				-	-	-	-	-	-	-
									5,356.19	
Demand										
Procurement Expenses		DEM01		80,256	20,813	6,844	14,914	3,170	5,356	29,159
Storage		DEM02		1.0000	0.4753	0.1568	0.3679	-	-	-
					0.4753	0.1568	0.3679			
Transmission		DEM03		80,256	20,813	6,844	14,914	3,170	5,356	29,159
Distribution Structures		DEM04		45,903	20,813	6,844	14,914	3,170	162	-
Distribution Mains		DEM05		45,903	20,813	6,844	14,914	3,170	162	-
Customer										
Distribution Mains (Year-end Customers)		CUST01		36,126	30,826	4,295	963	41	1	-
Services		CUST02		28,599,210	23,554,455	3,057,954	1,899,989	80,893	5,919	-
Meters		CUST03		18,253,935	12,302,965	2,754,684	2,806,440	348,746	41,100	-
Customer Count (Average)				35,915	30,680	4,236	957	38	4	-
Customer Accounts		CUST04		39,032	30,680	4,236	3,828	152	16	120
Customer Service		CUST05		35,915	30,680	4,236	957	38	4	-
Forfeited Discounts		REVFD		2,641,717	2,168,773	432,108	9,080	2,703	18,740	9,961

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Customer Related Unit Cost										
Rate Base				$ 45,545,274	$ 36,717,752	$ 5,653,335	$ 2,891,820	$ 255,640	$ 26,259	$ 469
Rate of Return				8.66%	8.66%	8.66%	8.66%	8.66%	8.66%	8.66%
Return				$ 3,945,802	$ 3,181,032	$ 489,775	$ 250,532	$ 22,147	$ 2,275	$ 41
Income Taxes				$ 858,186	$ (345,915)	$ 200,335	$ 200,699	$ 58,630	$ (1,867)	$ 14
Operation and Maintenance Expenses				6,108,069	4,896,981	740,705	430,692	32,559	3,365	3,767
Depreciation Expenses				1,540,659	1,214,624	196,863	116,472	11,462	1,237	-
Other Taxes				870,064	700,077	106,930	57,584	4,760	490	224
Expense Adjustment (Classified Pro-Rata on the basis of Operating Expenses)				721,347	620,373	72,702	48,166	3,545	410	322
Total Customer-Related Revenue Requirement				$ 14,044,127	$ 10,267,172	$ 1,807,309	$ 1,104,146	$ 133,103	$ 5,910	$ 4,366
Less: Misc Service Revenues				(48,506)	(59,258)	(758)	(2,901)	-	-	-
Net Revenue Requirement				$ 13,995,621	$ 10,207,915	$ 1,806,551	$ 1,101,246	$ 133,103	$ 5,910	$ 4,366
Customer-Months				35,915	30,680	4,236	957	38	4	-
Customer-Related Unit Cost ($/Cust/Mo)				32.474	27.727	35.540	95.894	291.893	123.130	

Seelye Exhibit 7

Class Cost of Service Study

Storage Allocation Factor

DELTA NATURAL GAS COMPANY

Summary of Allocation of Underground Storage Investment

Calculation of Maximum Class Demands
On February 10th Design Day Assuming 68 Degree Days
<u>For Determination of Demand Allocation Factors</u>

	Total	Residential	Small Non Residential GS	Large Non Residential GS
Non-Temp Sensitive Load (per Day)	4,151	821	316	3,014
Temp Sensitive Load (per Degree Day)	565	294	96	175
Calculated Daily Requirements at -3 Degrees	42,571	20,813	6,844	14,914
Percentage of Total		48.89%	16.08%	35.03%

Allocation of Underground Storage

		Storage Withdrawals	Residential	Small Non Residential GS	Large Non Residential GS
Total Allocated Withdrawals Thru February 9th					
December		459,864	208,862	69,286	181,716
January		497,654	229,031	75,860	192,763
Feb. 1-9		154,734	70,673	23,429	60,632
	Total	1,112,252	508,566	168,575	435,111
Balance of Working Gas Allocated on the Basis of -3 Degree Feb. 10 Design Day		1,469,337	718,359	236,269	514,709
Total Working Gas		2,581,589	1,226,925	404,844	949,820
Total Allocation Factor For Underground Storage		1.000000	0.475260	0.156820	0.367921

DELTA NATURAL GAS COMPANY
Allocation of Underground Storage Investment

(November)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	821	316	3,014	4,151
Temperature Sensitive Load (per Degree Day)	294	96	175	565

		Requirements					Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Res GS	Large Non Res GS	Total	Storage Withdrawals (Injections)	Res	Small Non Res GS	Large Non Res GS
1	14	4,937	1,660	5,464	12,061	0	0	0	0
2	14	4,937	1,660	5,464	12,061	0	0	0	0
3	14	4,937	1,660	5,464	12,061	0	0	0	0
4	14	4,937	1,660	5,464	12,061	0	0	0	0
5	15	5,231	1,756	5,639	12,626	0	0	0	0
6	15	5,231	1,756	5,639	12,626	0	0	0	0
7	15	5,231	1,756	5,639	12,626	0	0	0	0
8	15	5,231	1,756	5,639	12,626	0	0	0	0
9	16	5,525	1,852	5,814	13,191	0	0	0	0
10	16	5,525	1,852	5,814	13,191	0	0	0	0
11	17	5,819	1,948	5,989	13,756	0	0	0	0
12	17	5,819	1,948	5,989	13,756	0	0	0	0
13	18	6,113	2,044	6,164	14,321	0	0	0	0
14	18	6,113	2,044	6,164	14,321	0	0	0	0
15	19	6,407	2,140	6,339	14,886	0	0	0	0
16	19	6,407	2,140	6,339	14,886	0	0	0	0
17	20	6,701	2,236	6,514	15,451	0	0	0	0
18	20	6,701	2,236	6,514	15,451	0	0	0	0
19	20	6,701	2,236	6,514	15,451	0	0	0	0
20	21	6,995	2,332	6,689	16,016	0	0	0	0
21	21	6,995	2,332	6,689	16,016	0	0	0	0
22	21	6,995	2,332	6,689	16,016	0	0	0	0
23	22	7,289	2,428	6,864	16,581	0	0	0	0
24	22	7,289	2,428	6,864	16,581	0	0	0	0
25	22	7,289	2,428	6,864	16,581	0	0	0	0
26	22	7,289	2,428	6,864	16,581	0	0	0	0
27	23	7,583	2,524	7,039	17,146	0	0	0	0
28	23	7,583	2,524	7,039	17,146	0	0	0	0
29	24	7,877	2,620	7,214	17,711	0	0	0	0
30	24	7,877	2,620	7,214	17,711	0	0	0	0
Total	561	189,564	63,336	188,595	441,495	0	0	0	0

DELTA NATURAL GAS COMPANY
Allocation of Underground Storage Investment

(December)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	821	316	3,014	4,151
Temperature Sensitive Load (per Degree Day)	294	96	175	565

		Requirements					Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Res GS	Large Non Res GS	Total	Storage Withdrawals (Injections)	Residential	Small Non Res GS	Large Non Res GS
1	25	8,171	2,716	7,389	18,276	13,649	6,102	2,028	5,518
2	25	8,171	2,716	7,389	18,276	12,537	5,605	1,863	5,069
3	26	8,465	2,812	7,564	18,841	12,556	5,641	1,874	5,041
4	26	8,465	2,812	7,564	18,841	13,466	6,050	2,010	5,406
5	26	8,465	2,812	7,564	18,841	13,859	6,227	2,068	5,564
6	26	8,465	2,812	7,564	18,841	13,994	6,287	2,089	5,618
7	26	8,465	2,812	7,564	18,841	14,387	6,464	2,147	5,776
8	26	8,465	2,812	7,564	18,841	14,388	6,464	2,147	5,776
9	27	8,759	2,908	7,739	19,406	14,390	6,495	2,156	5,739
10	27	8,759	2,908	7,739	19,406	14,391	6,495	2,157	5,739
11	27	8,759	2,908	7,739	19,406	13,950	6,296	2,090	5,563
12	28	9,053	3,004	7,914	19,971	14,342	6,501	2,157	5,683
13	28	9,053	3,004	7,914	19,971	14,343	6,502	2,157	5,684
14	28	9,053	3,004	7,914	19,971	14,735	6,679	2,216	5,839
15	29	9,347	3,100	8,089	20,536	14,735	6,706	2,224	5,804
16	29	9,347	3,100	8,089	20,536	14,753	6,715	2,227	5,811
17	29	9,347	3,100	8,089	20,536	14,753	6,715	2,227	5,811
18	29	9,347	3,100	8,089	20,536	15,144	6,893	2,286	5,965
19	30	9,641	3,196	8,264	21,101	15,144	6,919	2,294	5,931
20	30	9,641	3,196	8,264	21,101	15,535	7,098	2,353	6,084
21	30	9,641	3,196	8,264	21,101	15,483	7,074	2,345	6,064
22	30	9,641	3,196	8,264	21,101	15,483	7,074	2,345	6,064
23	30	9,641	3,196	8,264	21,101	15,874	7,253	2,404	6,217
24	30	9,641	3,196	8,264	21,101	15,874	7,253	2,404	6,217
25	30	9,641	3,196	8,264	21,101	15,874	7,253	2,404	6,217
26	30	9,641	3,196	8,264	21,101	16,007	7,314	2,424	6,269
27	31	9,935	3,292	8,439	21,666	16,007	7,340	2,432	6,235
28	31	9,935	3,292	8,439	21,666	16,007	7,340	2,432	6,235
29	31	9,935	3,292	8,439	21,666	16,069	7,369	2,442	6,259
30	31	9,935	3,292	8,439	21,666	16,069	7,369	2,442	6,259
31	31	9,935	3,292	8,439	21,666	16,069	7,369	2,442	6,259
Total	882	284,759	94,468	247,784	627,011	459,867	208,862	69,286	181,716

DELTA NATURAL GAS COMPANY
Allocation of Underground Storage Investment

(January)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	821	316	3,014	4,151
Temperature Sensitive Load (per Degree Day)	294	96	175	565

		Requirements					Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Res GS	Large Non Res GS	Total	Storage Withdrawals (Injections)	Residential	Small Non Res GS	Large Non Res GS
1	31	9,935	3,292	8,439	21,666	15,613	7,159	2,372	6,081
2	31	9,935	3,292	8,439	21,666	15,586	7,147	2,368	6,071
3	31	9,935	3,292	8,439	21,666	15,602	7,154	2,371	6,077
4	31	9,935	3,292	8,439	21,666	15,596	7,152	2,370	6,075
5	32	10,229	3,388	8,614	22,231	15,602	7,179	2,378	6,046
6	32	10,229	3,388	8,614	22,231	15,728	7,237	2,397	6,094
7	32	10,229	3,388	8,614	22,231	15,727	7,236	2,397	6,094
8	32	10,229	3,388	8,614	22,231	15,734	7,240	2,398	6,097
9	32	10,229	3,388	8,614	22,231	15,731	7,238	2,397	6,095
10	32	10,229	3,388	8,614	22,231	15,722	7,234	2,396	6,092
11	32	10,229	3,388	8,614	22,231	15,745	7,245	2,400	6,101
12	33	10,523	3,484	8,789	22,796	15,720	7,257	2,403	6,061
13	33	10,523	3,484	8,789	22,796	15,712	7,253	2,401	6,058
14	33	10,523	3,484	8,789	22,796	15,681	7,239	2,397	6,046
15	34	10,817	3,580	8,964	23,361	15,720	7,279	2,409	6,032
16	34	10,817	3,580	8,964	23,361	16,115	7,462	2,470	6,184
17	34	10,817	3,580	8,964	23,361	16,107	7,458	2,468	6,181
18	33	10,523	3,484	8,789	22,796	16,109	7,436	2,462	6,211
19	33	10,523	3,484	8,789	22,796	16,133	7,447	2,466	6,220
20	33	10,523	3,484	8,789	22,796	16,112	7,438	2,463	6,212
21	32	10,229	3,388	8,614	22,231	15,992	7,358	2,437	6,197
22	32	10,229	3,388	8,614	22,231	15,999	7,362	2,438	6,199
23	32	10,229	3,388	8,614	22,231	16,000	7,362	2,438	6,200
24	32	10,229	3,388	8,614	22,231	16,390	7,541	2,498	6,351
25	32	10,229	3,388	8,614	22,231	16,390	7,541	2,498	6,351
26	32	10,229	3,388	8,614	22,231	16,523	7,602	2,518	6,402
27	31	9,935	3,292	8,439	21,666	16,912	7,755	2,570	6,587
28	31	9,935	3,292	8,439	21,666	16,912	7,755	2,570	6,587
29	31	9,935	3,292	8,439	21,666	16,912	7,755	2,570	6,587
30	31	9,935	3,292	8,439	21,666	16,912	7,755	2,570	6,587
31	31	9,935	3,292	8,439	21,666	16,912	7,755	2,570	6,587
Total	995	317,981	105,316	267,559	690,856	497,654	229,031	75,860	192,763

DELTA NATURAL GAS COMPANY
Allocation of Underground Storage Investment

(February)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	821	316	3,014	4,151
Temperature Sensitive Load (per Degree Day)	294	96	175	565

		Requirements					Storage Allocation		
Date	**Heating Degree Days**	**Residential**	**Small Non Res GS**	**Large Non Res GS**	**Total**	**Storage Withdrawals (Injections)**	**Residential**	**Small Non Res GS**	**Large Non Res GS**
1	31	9,935	3,292	8,439	21,666	16,348	7,497	2,484	6,368
2	30	9,641	3,196	8,264	21,101	16,321	7,457	2,472	6,392
3	30	9,641	3,196	8,264	21,101	15,952	7,288	2,416	6,247
4	30	9,641	3,196	8,264	21,101	15,560	7,109	2,357	6,094
5	30	9,641	3,196	8,264	21,101	15,180	6,936	2,299	5,945
6	30	9,641	3,196	8,264	21,101	15,306	6,993	2,318	5,994
7	30	9,641	3,196	8,264	21,101	15,305	6,993	2,318	5,994
8	30	9,641	3,196	8,264	21,101	14,926	6,820	2,261	5,846
9	29	9,347	3,100	8,089	20,536	14,923	6,792	2,253	5,878
10	29	9,347	3,100	8,089	20,536	14,914	6,788	2,251	5,874
Total	299	96,116	31,864	82,465	210,445	154,734	70,673	23,429	60,632

Seelye Exhibit 8

Class Cost of Service Study

Zero Intercept Analysis

Delta Natural Gas Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2009

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per Foot)	1.0559793	0.5323013
Zero Intercept ($ per Foot)	5.6479737	1.5668682
R-Square	0.9474806	

Plant Classification

Total Number of Units	7,802,022
Zero Intercept	5.6479737
Zero Intercept Cost	$ 44,065,615
Total Cost of Sample	$ 65,974,747
Percentage of Total	0.667916396
Percentage Classified as Customer-Related	66.79%
Percentage Classified as Demand-Related	33.21%

Delta Natural Gas Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2009

Description	Pipe Size		Net Cost of Plant	Quantity (Feet)	Unit Cost ($ per Foot)
Distribution Main Pipe, Under 2" Plastic	1.500	$	4,526,325	511,979	8.84084
Distribution Main Pipe, 2" Plastic	2.000	$	35,810,174	4,656,267	7.69075
Distribution Main Pipe, 3" Plastic	3.000	$	233,177	89,043	2.61870
Distribution Main Pipe, 4" Plastic	4.000	$	17,279,740	1,425,318	12.12343
Distribution Main Pipe, 6" Plastic	6.000	$	925,501	59,768	15.48489
Distribution Main Pipe, Under 2" Steel	1.500	$	212,739	78,268	2.71808
Distribution Main Pipe, 2" Steel	2.000	$	685,650	287,587	2.38415
Distribution Main Pipe, 3" Steel	3.000	$	110,787	52,022	2.12962
Distribution Main Pipe, 4" Steel	4.000	$	3,093,182	274,404	11.27236
Distribution Main Pipe, 6" Steel	6.000	$	2,194,153	272,503	8.05185
Distribution Main Pipe, 8" Steel	8.000	$	903,319	94,863	9.52235
Total		$	65,974,747.00	7,802,022	

Seelye Exhibit 9

Temperature Normalization
Adjustment

Delta Natural Gas Company, Inc.

Natural Gas Temperature Normalization Adjustment
For the 12 months Ended December 31, 2009

Consumption Not Billed under the Weather Normalization Clause

	Cycle Billing Basis	Calendar Basis
Normal Heating Degree Days	4,603	4,623
Actual Heating Degree Days	4,592	4,636
Normal over (under) Actual	11	(13)

	Cycle Billing Basis	Calendar Basis
Normal Heating Degree Days **(7 Non-WNA Months)**	795	998
Actual Heating Degree Days **(7 Non-WNA Months)**	863	997
Normal over (under) Actual	(68)	1

	(1) Total Mcf	(2) Non-Temp Mcf	(3) Non-Temp Mcf Full Year (Column (1) x 6)	(4) Temperature Sensitive Mcf (Column (1) - (3))	(5) Actual Degree Days	(6) Mcf per Degree Days (Column (4) x (5))	(7) Normal Degree Days	(8) Departure From Normal (Column (7) - (5))	(9) Normal Temperature Adjustment (Column (6) x (8))	(10) Net Revenue Per Mcf Sold	(11) Net Revenue Adjustment (Column (9) x (10))
Residential *	351,111	49,875	174,562	176,549	863	205	795	(68)	(13,940)	$ 4.1580	$ (57,962.52)
Small Non-Residential General Service *	107,163	18,794	65,780	41,384	863	48	795	(68)	(3,264)	$ 4.1580	$ (13,571.71)
Large Non-Residential GS - Commercial	754,173	43,619	261,715	492,458	4,592	107	4,603	11	1,177	$ 4.1580	$ 4,893.97
Large Non-Residential GS - Industrial	81,222	3,131	18,783	62,439	4,592	14	4,603	11	154	$ 4.1580	$ 640.33
Interruptible Service - Commercial	2,210	-	-	2,210	4,592	0	4,603	11	-	$ 1.6000	$ -
Interruptible Service - Industrial	25,265	1,724	10,342	14,923	4,592	3	4,603	11	33	$ 1.6000	$ 52.80
Small Non Residential General Service -Transportation	37,952	369	2,216	35,736	4,592	8	4,603	11	88	$ 4.1580	$ 365.90
Large Non Residential General Service -Transportation	1,068,708	136,561	819,365	249,343	4,592	54	4,603	11	594	$ 4.1580	$ 2,469.85
Residential - Transportation	1,261	15	89	1,172	4,592	0	4,603	11	-	$ 4.1580	$ -
	2,429,066	254,087	1,352,852	1,076,214					(15,158)		$ (63,111.38)

* For the seven months May to November only

Seelye Exhibit 10

Year-End Customer
Adjustment

Not Proposed

Delta Natural G ompany, Inc.

Adjustment of Gas Rev. .o reflect Year-end Customers
Over Average Number of Customers in Test Period
12 Months Ended December 31, 2009

	Average Number of Customers	Customers Served at 12/31/09	Year-End Over (Under) Average (Col. 2 - 1)	Customer Charge	Additional Customer Charge Revenue (Col. 3 x 4)	Weather Normalized Mcf	Average Mcf per Customer (COL. 6 / 1)	Year -End Mcf Adjustment (COL. 7 x 3)	Net Revenue per Mcf Commodity	Additional Revenue Commodity (COL. 8 x 9)	Year-End Revenue Adjustment (COL. 5 + 10)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential	30,660	30,826	166	$ 15.30	$ 2,539.80	1,857,139	60.6	10,055	$ 4.1580	$ 41,808.69	$ 44,348.49
Small Non-Residential GS	4,233	4,295	62	$ 25.00	$ 1,550.00	605,173	143.0	8,864	$ 4.1580	$ 36,856.51	$ 38,406.51
Large Non-Residential GS - Retail	955	963	8	$ 100.00	$ 800.00	2,253,407	2,359.6	18,877		$ 49,188.08	$ 49,988.08
First 200 Mcf						772,185		6,466	$ 4.1580	$ 26,885.63	
Next 800 Mcf						431,115		3,612	$ 2.5091	$ 9,062.87	
Next 4,000 Mcf						607,467		5,089	$ 1.7130	$ 8,717.46	
Next 5,000 Mcf						235,080		1,970	$ 1.3130	$ 2,586.61	
Over 10,000 Mcf						207,560		1,739	$ 1.1130	$ 1,935.51	
Interruptible	43	41	(2)	$ 250.00	$ (500.00)	1,254,621	29,177.2	(58,354)		$ (70,531.00)	$ (71,031.00)
						326,478		(15,185)	$ 1.6000	$ (24,296.00)	
						657,056		(30,561)	$ 1.2000	$ (36,673.20)	
						214,604		(9,982)	$ 0.8000	$ (7,985.60)	
						56,483		(2,627)	$ 0.6000	$ (1,576.20)	
On System Transportation Special	4	4	-		$ -	2,801,367	700,341.8	-	$ -	$ -	$ -
	35,895	36,129	234		$ 4,389.80	8,771,707		(20,558)		$ 57,322.28	$ 61,712.08
Expenses at an Operating Ratio of -				0.3191							19,690
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES											$ 42,022

CALCULATION OF GAS OPERATING RATIO

TOTAL GAS OPERATING EXPENSES	51,967,303
LESS GAS SUPPLY EXPENSES	32,945,385
LESS WAGES AND SALARIES	6,907,866
LESS PENSIONS AND BENEFITS	2,989,151
LESS REGULATORY COMMISSION EXPENSE	189,509
NET EXPENSES	8,935,392

TOTAL GAS OPERATIONS REVENUES (AS BILLED)	60,950,552
LESS GSC REVENUE	32,945,718
NET REVENUE	28,004,834
OPERATING RATIO	0.3191

Seelye Exhibit 11

Depreciation Study

Delta Natural Gas Company, Inc.
Depreciation Study
December 31, 2009

Overview

The purpose of performing a depreciation study is to insure that the depreciation expenses recorded by the utility and included in the cost of service represent a reasonably accurate and systematic measurement of the annual accrual levels necessary to distribute plant costs, less salvage and removal, over the estimated useful life of the assets.

In performing this study, data was compiled showing plant additions, retirements and transfers going back as far as the 1940s. For certain plant accounts, such as distribution mains (Account 376), meters (Account 381), and house regulators (Account 383), data was available going back well into the 1940s. Many other accounts were not utilized until the 1950s, 1960s or later.

Where sufficient data was available, the average service lives ("ASLs") were determined by identifying the survivor curve and associated ASL that best fit the pattern of retirements from the historical data provided by Delta Natural Gas Company, Inc. ("Delta"). In general, the survivor curves and ASLs were identified that produced the lowest sum of square deviations between the actual balances and simulated balances.[1] The simulated balances were determined by applying various survivor curves to the plant additions and transfers for each plant account for which data was available and then computing the resultant plant balances. The sum of square deviations were calculated based on the difference between the computed plant balances and actual plant balances. In selecting a survivor curve and ASL, several goodness-of-fit statistics were examined: (1) sum of squared deviations ("SSD"), (2) conformance index ("CI"), (3) index of variation ("IV"), and (4) retirement experience index ("REI").[2]

Where sufficient data was not available, the ASLs and depreciation accrual rates of neighboring utilities and judgment were used as a guide in developing the proposed depreciation rates.

The survivor curves utilized in this study correspond to the "Iowa" curves that were developed under the direction of Robley Winfrey at Iowa State University, as described in various bulletins and publications.[3] These curves are still widely used within the industry.

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[1] A detailed description of the simulated plant record ("SPR") method is included in *Public Utility Depreciation Practices,* August 1996, published by the National Association of Regulatory Commissioners ("NARUC").
[2] Ibid., at pp. 92-97.
[3] See Winfrey, Robley, *Depreciation of Group Properties*, Bulletin 155 (Iowa State University, Engineering Research Institute, reprinted 1969); Winfrey, Robley, *Statistical Analyses of Industrial Property Retirements*, Bulletin 125 (Iowa State University, Engineering Research Institute, revised 1967); Winfrey, Robley, *Condition – Percent Tables for Depreciation of Unit and Group Properties*, Bulletin 156 (Iowa State University, Engineering Research Institute, reprinted 1970); Marston, Anson, Winfrey, Robley, and Hepstead, Jean C., *Engineering Valuation and Depreciation* (Iowa State University Press, 1963).

The depreciation accrual rates were calculated using the average service life depreciation procedure, the straight-line method, and the remaining life basis. Using this approach, the remaining life annual accrual for each category of plant was determined by dividing the original cost less book reserve by the average remaining life determined based on the selected survivor curve. The average remaining life is a weighted average derived from the estimated future survivor curve based on the age of the actual plant additions. The annual depreciation amount is determined by dividing the net plant balance to be recovered by the estimated remaining life. The depreciation accrual rate is then calculated by dividing the annual depreciation amount by the plant balance for the account.

A table showing the current and proposed depreciation accrual rates is included in Appendix A. The Summary of Results included in Appendix B shows the plant balances, the survivor curve, ASL, estimated salvage percentage, net salvage amount, depreciation reserve per books, balance to be recovered, estimated remaining life, annual depreciation amount and base accrual rate for those plant accounts for which sufficient data were available to estimate ASLs and survivor curves. For those accounts for which sufficient data was not available, only the base accrual rates are shown. Historical data and the average remaining life calculations based on the selected survivor curves are included in Appendix C. The results of the study are described below.

<u>Distribution Plant</u>

Account 375 – Distribution Structures and Improvements

Delta's records indicated plant additions dating back to 1951. The current depreciation accrual rate for this account is 2.67%. The survivor curve that best fit the data was the L3 curve with an ASL of 35 years. Using these parameters, the average remaining life is calculated to be 15.5 years. There has been no salvage experienced for this account and none is anticipated. Based on a plant balance of $112,359, the recommended accrual rate is 2.67%, which is identical to the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 376 – Distribution Mains

This is the account with the largest amount of assets. Delta's records indicated plant additions dating back to 1940. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R2 curve with an ASL of 34 years provided solid results for all four metrics. Using an R2 curve with an ASL of 34 years, the average remaining life is calculated to be 20.3 years. There has been no salvage experienced for this account and none is anticipated. Based on a plant balance of $65,974,747, the calculated accrual rate is 3.11%, which is higher than the current rate of 1.41%. Although the higher rate could be supported from the data, it is recommended that Delta increase the rate only to 2.22%. This recommendation is based on judgment and is reasonable compared with other gas distribution utilities in the region.

Account 378 – Measuring and Regulator Station Equipment - Distribution

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 3.28%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the L0 curve with an ASL of 30 years provided solid results for all four metrics. Using an L0 curve with an ASL of 30 years, the average remaining life is calculated to be 22.2 years. The salvage rate is expected to be –10% for this account due to removal cost. Based on a plant balance of $1,396,756, the recommended accrual rate is 3.98%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 379 – Measuring and Regulator Station Equipment – City Gate

Delta's records indicated plant additions dating back to 1950. The current depreciation accrual rate for this account is 3.01%. An R1 curve was chosen for this plant account because it had good statistical results and is a common curve used for this account in the industry. Using an R1 curve with an ASL of 40 years, the average remaining life is calculated to be 26.7 years. The salvage rate is expected to be –10% for this account due to removal cost. Based on a plant balance of $500,033, the recommended accrual rate is 2.80%, which is slightly lower than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 380 – Services – Distribution

Because distribution services were recorded as distribution mains (Account 376) for a number of years, there was not sufficient data to develop survivor curves based on Delta's plant additions and retirements for distribution services. Delta is currently using a depreciation accrual rate of 1.41% for Account 380. The plant balance is $13,562,075. The recommended accrual rate for this account is 3.07%. This is reasonable compared with other gas distribution utilities in the region.

Account 381 – Meters

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 2.28%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the S4 curve with an ASL of 36 years provided excellent results for all four metrics. Using an S4 curve with an ASL of 36 years, the average remaining life is calculated to be 21.4 years. No salvage is anticipated in the future for this account. Based on a plant balance of $9,302,928 the recommended accrual rate is 3.14%, which is higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 382 – Meters & Regulator Installations

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 2.33%. An S1 curve was chosen for this plant account because it had sound statistical results. Using an S1 curve with an ASL of 32 years, the average remaining life is calculated to be 18.2 years. The salvage rate is expected to be -45% for this account due to removal cost. Based on a plant balance of $3,186,037, the calculated accrual rate is 5.08%, which is higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 383 – House Regulators

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 3.80%. The S0 curve with an ASL of 30 years was chosen because it produced sound statistical results and maximized all four of the statistics examined (SSD, CI, IV and REI). Using an S0 curve with an ASL of 30 years, the average remaining life is calculated to be 20.0 years. Salvage is anticipated to be 5%. Based on a plant balance of $3,478,550, the recommended accrual rate is 3.88%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 385 – Industrial Measuring and Regulator Station Equipment - Distribution

Delta's records indicated plant additions dating back to 1956. The current depreciation accrual rate for this account is 2.31%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the L0 curve with an ASL of 40 years provided sound results for all four metrics. Using an L0 curve with an ASL of 40 years, the average remaining life is calculated to be 31.6 years. Salvage is anticipated to be -10% due to removal cost. Based on a plant balance of $1,567,108, the recommended accrual rate is 2.57%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Gathering and Transmission Plant

Account 305 – Structures and Improvements – Manufactured Gas Plant

There is currently no plant balance for this account. The depreciation rate for this account was 2.20%. If additional investment were made in this account, we would recommend using Delta's existing rate of 2.20%.

Account 325 – Gathering Land & Rights

Delta's records indicated plant additions dating back to 1959. The plant balance is $79,004. The current depreciation accrual rate for this account is 3.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment, we are not proposing to modify the existing accrual rate of 3.00%.

Account 327 – Compressor Station Structures

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for this account. Delta is currently using a depreciation accrual rate of 3.00% for Account 327. We are recommending that Delta maintain its current accrual rate of 3.00%. The plant balance is $45,721.

Account 331 – Producing Gas Wells – Well Equipment

Delta's records indicated plant additions dating back to 1969. The plant balance is $7,795. However, the plant in this account is fully depreciated. If additional investment were made in this account, we would recommend using Delta's existing rate of 4.00%.

Account 332 – Gathering Lines

The retirement data for this account produce curves with poor statistical results. Delta is currently using a depreciation accrual rate of 2.25% for Account 332, which has a balance of $1,915,975. We are recommending that Delta maintain its current accrual rate of 2.25%.

Account 333 – Gathering Compressor Stations

Delta's records indicated plant additions dating back only to 1986. The plant balance is $749,211. The current depreciation accrual rate for this account is 4.00%. The curve fitting statistics were poor for all survivor curve types. We are recommending that Delta maintain its current accrual rate of 4.00%.

Account 334 – Gathering Lines

The retirement data for this account produce curves with poor statistical results. Delta is currently using a depreciation accrual rate of 4.00% for Account 334, which has a balance of $147,297. We are recommending that Delta maintain its current accrual rate of 2.72%.

Account 365.3 – Land Rights

Delta's records indicated plant additions dating back to 1958. The current depreciation accrual rate for this account is 2.50%. Based on a plant balance of $163,626, we recommend that Delta maintain the accrual rate of 2.50%.

Account 366 – Structures and Improvements - Transmission

Delta's records indicated plant additions dating back to 1951. The plant balance is $244,453. The current depreciation accrual rate for this account is 2.00%. There has been no salvage experienced for this account and none is anticipated. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R1 curve with an ASL of 38 years provided excellent results for all four metrics. Using an R1 curve with an ASL of 38 years, the average remaining life is calculated to be 28.3 years. We recommend an accrual rate of 2.49%, which is higher than the existing rate.

Account 367 – Mains - Transmission

Delta's records indicated plant additions dating back to 1951. The current depreciation accrual rate for this account is 2.24%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the L0 curve with an ASL of 35 years provided excellent results for all four metrics. Using an L0 curve with an ASL of 35 years, the average remaining life is calculated to be 26.6 years. No salvage is anticipated for this account. Based on a plant balance of $42,014,896, the recommended accrual rate is 2.52%, which is slightly higher than the current rate.

Account 368 – Compressor Station Equipment - Transmission

Delta's records indicated plant additions dating back to 1961. The plant balance is $7,498,154. The current depreciation accrual rate for this account is 2.00%. Delta made significant additions to plant since 2006 -- more than tripling the balance of plant since that time. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the L2 curve with an ASL of 32 years provided excellent results for all four metrics. Using an L2 curve with an ASL of 32 years, the average remaining life is calculated to be 25.1 years, we are recommending that Delta increase its accrual rate to 3.43%.

Account 369 – Measuring and Regulator Station Equipment - Transmission

Delta's records indicated plant additions dating back to 1951. The current depreciation accrual rate for this account is 2.22%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the L0 curve with an ASL of 26 years provided excellent results for all four metrics. Using an L0 curve with an ASL of 26 years, the average remaining life is calculated to be 21.0 years. Salvage is expected to be –10% due to removal cost. Based on a plant balance of $3,380,321, the recommended accrual rate is 4.30%, which is higher than the current rate.

Account 371 – Other Equipment - Transmission

Delta's records indicated plant additions dating back to 1959. The plant balance is $445,043. The current depreciation accrual rate for this account is 2.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, we are proposing that Delta maintain its accrual rate of 2.00%.

Storage Plant

Account 351 -- Storage Structures and Improvements

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.20% for Account 351. Continuing the accrual rate of 2.20% is recommended based on an expected remaining life of 29.0 years. The plant balance is $292,484. The recommended accrual rate is consistent with other utilities in the region.

Account 352 -- Storage Wells

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.19% for Account 352. Maintaining an accrual rate of 2.19% is recommended based on an expected remaining life of approximately 29.0 years. The plant balance is $2,876,146. The recommended accrual rate is consistent with other utilities in the region.

Account 352.1 -- Storage Rights

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.85% for Account 352.1. Maintaining an accrual rate of 1.85% is recommended based on an expected remaining life of approximately 29.0 years. The plant balance is $860,396. The recommended accrual rate is consistent with other utilities in the region.

Account 352.2 -- Storage Reservoirs

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.78% for Account 352.2. Maintaining an accrual rate of 1.78% is recommended based on an expected remaining life of approximately 29.0 years. The plant balance is $1,881,731. The recommended accrual rate is consistent with other utilities in the region.

Account 352.3 -- Storage Nonrec Natural Gas

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.75% for Account 352.3. Maintaining an accrual rate of 1.75% is recommended based on an expected remaining life of approximately 29.0 years. The plant balance is $294,307. The recommended accrual rate is consistent with other utilities in the region.

Account 353 -- Storage Lines

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.05% for Account 353. Maintaining an accrual rate of 2.05% is recommended based on an expected remaining life of approximately 29.0 years. The plant balance is $5,102,436. The recommended accrual rate is consistent with other utilities in the region.

Account 354 -- Storage Compressor Lines

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.90% for Account 354. Maintaining an accrual rate of 1.90% is recommended based on an expected remaining life of approximately 29.0 years. The plant balance is $2,526,069. The recommended accrual rate is consistent with other utilities in the region.

Account 355 -- Storage Measuring and Regulator Equipment

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.41% for Account 355. Maintaining an accrual rate of 2.69% is recommended based on an expected remaining life of approximately 29.0 years. The plant balance is $379,709. The recommended accrual rate is consistent with other utilities in the region.

Account 356 – Purification Equipment

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.91% for Account 356. Maintaining an accrual rate of 1.91% is recommended based on an expected remaining life of approximately 23.0 years. The plant balance is $409,570. The recommended accrual rate is consistent with other utilities in the region.

Account 357 – Storage Other Equipment

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 0.53% for Account 357. Maintaining an accrual rate of 0.53% is recommended based on an expected remaining life of approximately 23.0 years. The plant balance is $47,209. The recommended accrual rate is consistent with other utilities in the region.

General Plant

Account 390 – Structures and Improvements

Delta's records indicated plant additions dating back to 1958. The current depreciation accrual rate for this account is 2.00% While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the L0 curve with an ASL of 35 years provided solid results for all four metrics. Using an L0 curve with an ASL of 35 years, the average remaining life is calculated to be 27.0 years. The salvage rate is expected to be 40% for this account. Based on a plant balance of $5,355,492, it is recommended that Delta maintain the current accrual rate of 2.00%. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 391 – Office Furniture

The retirement data did not produce a curve with sufficient statistical results. Delta is currently using a depreciation accrual rate of 1.00% for Account 391. The plant balance is $146,777 and the salvage rate is expected to be 5% for this account. It is recommended that Delta maintain the accrual rate of 1.00%, which will remain in line with other utilities in the region.

Account 392 – Transportation Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were marginal for all survivor curve types. The existing accrual rate is 8.14% and the plant balance is $4,201,697. Salvage rate is estimated at 30%. It is recommended that Delta maintain use of 8.14% for this account. This accrual rate is in line with other utilities in the region.

Account 393 – Stores Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were marginal for all survivor curve types. The plant balance is $36,011. It is recommended that Delta maintain the current accrual rate of 2.00%, which is in line with other utilities in the region.

Account 394 – Tools and Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were poor for all survivor curve types. The plant balance is $703,034. It is recommended that Delta maintain the existing accrual rate of 4.00%, which is in line with other utilities in the region.

Account 395 – Laboratory Equipment

Delta's records indicated plant additions dating back to 1957. The current depreciation accrual rate for this account is 5.00%. The plant balance is $237,610. After reviewing the account we recommend that the depreciation rate be maintained at 5.00%, which is in line with other utilities in the region.

Account 396 – Power Operated Equipment

Delta's records indicated plant additions dating back to 1964. The current depreciation accrual rate for this account is 2.00%. The curve fitting statistics were poor for all survivor curve types. The plant balance is $3,294,567. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, it is recommended that Delta maintain the existing accrual rate of 2.00%.

Account 397 – Communication Equipment

The retirement data did not produce a curve with sufficient statistical results. Delta is currently using a depreciation accrual rate of 5.00% for Account 397. The plant balance is $386,003. It is recommended that Delta maintain the current accrual rate of 5.00%, which will remain in line with other utilities in the region.

Account 398 – Miscellaneous Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were poor for all survivor curve types. Delta is currently using a depreciation accrual rate of 2.00% for Account 398, which has a balance of $44,382. It is recommended that Delta maintain the existing accrual rate of 2.00%, which will remain in line with other utilities in the region.

Account 399.1 – Other Tangible Property – Mapping Software

The current depreciation accrual rate for this account is 4.0%. It is recommended that Delta maintain this accrual rate. The plant balance is $638,509.

Account 399.2 – Other Tangible Property – Computer Software

The current depreciation accrual rate for this account is 10.0%. Based on judgment concerning the expected rate of obsolescence for this type of property, it is recommended that Delta maintain the existing accrual rate, consistent with other utilities in the region.

Account 399.3 – Other Tangible Property – Computer Hardware

The current depreciation accrual rate for this account is 10.0%. Based on judgment concerning the expected rate of obsolescence for this type of property, it is recommended that Delta maintain the existing accrual rate, consistent with other utilities in the region.

Appendix A

Delta Natural Gas Company
Depreciation Study

Proposed Depreciation Rates

Account		Current Accrual Rate	Proposed Accrual Rate
		2.20%	2.20%
305	Structures & Improvements - Manufactured Gas Plant	3.00%	3.00%
325	Gathering Land & Rights	3.00%	3.00%
327	Comp Stattion Structures	4.00%	4.00%
331	Producing Gas Wells – Well Equipment	2.25%	2.25%
332	Gathering Lines	4.00%	4.00%
333	Gathering Compressor Stations	2.72%	2.72%
334	Gathering Measuring and Regulator Station Equipment		
339	Gathering Asset Retirement Cost	5.00%	5.00%
350.06	Gas Rights Storage	2.20%	2.20%
351	Storage Structures and Improvements	2.19%	2.19%
352	Storage Wells	1.85%	1.85%
3521	Storage Rights	1.78%	1.78%
3522	Storage Resevoirs	1.75%	1.75%
3523	Storage Nonrec Natural Gas	2.05%	2.05%
353	Storage Lines	1.90%	1.90%
354	Storage Compressor Stations	2.41%	2.41%
355	Storage Measuring and Regulator Equipment	1.91%	1.91%
356	Purification Equipment	0.53%	0.53%
357	Storage Other Equipment		
358	Storage Asset Retirement Cost		
3651	Tansmission Land & Rights		
3652	Rights of Way	2.50%	2.50%
3653	Land Rights	2.00%	2.49%
366	Structures & Improvements - Transmission	2.24%	2.52%
367	Mains – Transmission	2.00%	3.43%
368	Compressor Station Equipment – Transmission	2.22%	4.30%
369	Measuring and Regulator Station Equipment – Transmission	2.00%	2.00%
371	Other Equipment – Transmission		
372	Transmission Asset Retirement Cost		
374	Distribution Rights of Way		
3741	Distribtuion Land	2.67%	2.67%
375	Structures and Improvements – Distribution	1.41%	2.22%
376	Mains -- Distribution	3.28%	3.98%
378	Measuring and Regulator Station Equipment -- Distribution	3.01%	2.80%
379	Measuring and Regulator Station Equipment – City Gate	1.41%	3.07%
380	Services -- Distribution	2.28%	3.14%
381	Meters	2.33%	5.08%
382	Meter & Regulator Installations	3.80%	3.88%
383	Houes Regulators	2.31%	2.57%
385	Industrial Measuring and Regulator Station Equipment – Distribution		
388	Distribution Asset Retirement Cost		
389	Land and Land Rights	2.00%	2.00%
390	Structures and Improvements – General Plant	1.00%	1.00%
391	Office Furniture and Equipment -- General Plant	8.14%	8.14%
392	Transportation Equipment	2.00%	2.00%
393	Stores Equipment	4.00%	4.00%
394	Tools & Equipment		
39401	Comp Nat Gas Stat	5.00%	5.00%
395	Laboratory Equipment	2.00%	2.00%
396	Power Operated Equipment	5.00%	5.00%
397	Communication Equipment	2.00%	2.00%
398	Miscellaneous Equipment	4.00%	4.00%
399.1	Other Tangible Property -- Mapping Costs	10.00%	10.00%
399.2	Other Tangible Property -- Computer Software	10.00%	10.00%
399031	Computerized Office Equipment	10.00%	10.00%
39903	Computer Hardware		

Appendix B

Delta Natural [illegible] Company
Depreciation Study

Proposed Depreciation Rates

Account		Plant Balance	Dispersion	ASL	Estimated Salvage %	Net Salvage Amount	Depreciation Book Reserve	Balance To Be Recovered	Estimated Life Remaining	Annual Depreciation Amount	Base Accrual Rate
											2.20%
305	Structures & Improvements - Manufactured Gas Plant	$ 79,004			0%	$ -	$ 59,275	$ 19,729			3.00%
325	Gathering Land & Rights	$ 45,721				$ -	$ 28,429				3.00%
327	Comp Stattion Structures	$ 7,795			0%	$ -	$ 7,803	$ (8)			4.00%
331	Producing Gas Wells – Well Equipment	$ 1,915,975			0%	$ -	$ 1,345,777	$ 570,198	14.0	$ 40,728	2.25%
332	Gathering Lines	$ 749,211			0%	$ -	$ 559,404	$ 189,807			4.00%
333	Gathering Compressor Stations	$ 147,297			0%	$ -	$ 81,189	$ 66,108	15.0	$ 4,407	2.72%
334	Gathering Measuring and Regulator Station Equipment	$ 10,790					$ 10,744				
339	Gathering Asset Retirement Cost	$ -									5.00%
350.06	Gas Rights Storage	$ 292,484				$ -	$ 73,277	$ 219,207	29.0	$ 7,559	2.58%
351	Storage Structures and Improvements	$ 2,876,146				$ -	$ 214,801	$ 2,661,345	29.0	$ 91,771	3.19%
352	Storage Wells	$ 860,396				$ -	$ 399,900	$ 460,496	29.0	$ 15,879	1.85%
3521	Storage Rights	$ 1,881,731				$ -	$ 885,570	$ 996,161	29.0	$ 34,350	1.83%
3522	Storage Resevoirs	$ 294,307				$ -	$ 144,921	$ 149,386	29.0	$ 5,151	1.75%
3523	Storage Nonrec Natural Gas	$ 5,102,436				$ -	$ 2,070,537	$ 3,031,899	29.0	$ 104,548	2.05%
353	Storage Lines	$ 2,526,069				$ -	$ 1,088,735	$ 1,437,334	29.0	$ 49,563	1.96%
354	Storage Compressor Stations	$ 379,709				$ -	$ 94,900	$ 284,809	29.0	$ 9,821	2.59%
355	Storage Measuring and Regulator Equipment	$ 409,570				$ -	$ 108,901	$ 300,669	23.0	$ 13,073	3.19%
356	Purification Equipment	$ 47,209				$ -	$ 41,680	$ 5,529	23.0	$ 240	0.51%
357	Storage Other Equipment	$ 11,721					$ 3,723	$ 7,998			
358	Storage Asset Retirement Cost	$ 140,670					$ -				
3651	Tansmission Land & Rights	$ 1,215,558			0%	$ -	$ -	$ 1,215,558			
3652	Rights of Way	$ 163,626					$ 163,626				2.50%
3653	Land Rights	$ 244,453	R1	38	0%	$ -	$ 85,517	$ 158,936	28.3	$ 5,616	2.30%
366	Structures & Improvements - Transmission	$ 42,014,896	L0	35	0%	$ -	$ 15,753,075	$ 26,261,821	26.6	$ 987,287	2.35%
367	Mains – Transmission	$ 7,498,154	L2	32	0%	$ -	$ 1,368,920	$ 6,129,234	25.1	$ 244,193	3.26%
368	Compressor Station Equipment -- Transmission	$ 3,380,321	L0	26	-10%	$ (338,032.10)	$ 873,324	$ 2,506,997	21.0	$ 119,381	3.53%
369	Measuring and Regulator Station Equipment -- Transmission	$ 445,043			0%	$ -	$ 302,674	$ 142,369	14.6	$ 9,751	2.19%
371	Other Equipment – Transmission	$ 34,920					$ 9,914				
372	Transmission Asset Retirement Cost	$ 264,478					$ -				
374	Distribution Rights of Way	$ 63,206					$ -				
3741	Distribtuion Land	$ 112,359	L3	35	0%	$ -	$ 71,613	$ 40,746	15.5	$ 2,629	2.34%
375	Structures and Improvements – Distribution	$ 65,974,747	R2	34	0%	$ -	$ 24,354,420	$ 41,620,327	20.3	$ 2,050,262	3.11%
376	Mains – Distribution	$ 1,396,756	L0	30	-10%	$ (139,675.60)	$ 409,896	$ 986,860	22.2	$ 44,453	3.18%
378	Measuring and Regulator Station Equipment -- Distribution	$ 500,033	R1	40	-10%	$ (50,003.30)	$ 210,374	$ 289,659	26.7	$ 10,849	2.17%
379	Measuring and Regulator Station Equipment -- City Gate	$ 13,562,075					$ 2,295,296	$ 11,266,779			3.11%
380	Services – Distribution	$ 9,302,928	S4	36	0%	$ -	$ 3,525,902	$ 5,777,026	21.4	$ 269,954	2.90%
381	Meters	$ 3,186,037	S1	32	-45%	$ (1,433,716.65)	$ 865,590	$ 2,320,447	18.2	$ 127,497	4.00%
382	Meter & Regulator Installations	$ 3,478,550	S0	30	5%	$ 173,927.50	$ 1,487,565	$ 1,990,985	20.0	$ 99,549	4.13%
383	Houes Regulators	$ 1,567,108	L0	40	-10%	$ (156,710.80)	$ 502,983	$ 1,064,125	31.6	$ 33,675	2.15%
385	Industrial Measuring and Regulator Station Equipment – Distribution	$ 80,914					$ 110,027				
388	Distribution Asset Retirement Cost	$ 999,354									
389	Land and Land Rights	$ 5,355,492	L0	35	40%	$ 2,142,196.80	$ 1,989,928	$ 1,223,367	27.0	$ 45,310	2.00%
390	Structures and Improvements – General Plant	$ 146,777			5%	$ 7,338.85	$ 89,551	$ 49,887			1.00%
391	Office Furniture and Equipment -- General Plant	$ 4,201,697			30%	$ 1,260,509.10	$ 1,888,016	$ 1,053,172			8.14%
392	Transportation Equipment	$ 36,011			0%	$ -	$ 29,459	$ 6,552			2.00%
393	Stores Equipment	$ 703,034			5%	$ 35,151.70	$ 244,894	$ 422,988			4.00%
394	Tools & Equipment	$ 283,352					$ 283,352				
39401	Comp Nat Gas Stat	$ 237,610			0%	$ -	$ 165,850	$ 71,760			5.00%
395	Laboratory Equipment	$ 3,294,567			40%	$ 1,317,826.80	$ 1,614,109	$ 362,631			2.00%
396	Power Operated Equipment	$ 386,003			5%	$ 19,300.15	$ 237,639	$ 129,064			5.00%
397	Communication Equipment	$ 44,382			5%	$ 2,219.10	$ 36,590	$ 5,573			2.00%
398	Miscellaneous Equipment	$ 638,509			0%	$ -	$ 638,509	$ -			4.00%
399.1	Other Tangible Property -- Mapping Costs	$ 3,720,474			0%	$ -	$ 2,677,161	$ 1,043,313			10.00%
399.2	Other Tangible Property -- Computer Software	$ 226,689					$ 161,049				10.00%
399031	Computerized Office Equipment	$ 968,541					$ 767,947	$ 200,594			10.00%
39903	Computer Hardware										

Appendix C

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
366 -- Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	38	R1	-	-	2.30	-	-
1941	-	0	38	R1	-	-	2.60	-	-
1942	-	0	38	R1	-	-	2.90	-	-
1943	-	0	38	R1	-	-	3.19	-	-
1944	-	0	38	R1	-	-	3.49	-	-
1945	-	0	38	R1	-	-	3.79	-	-
1946	-	0	38	R1	-	-	4.09	-	-
1947	-	0	38	R1	-	-	4.39	-	-
1948	-	0	38	R1	-	-	4.71	-	-
1949	-	0	38	R1	-	-	5.02	-	-
1950	-	0	38	R1	-	-	5.35	-	-
1951	200	0	38	R1	5	-	5.67	-	30
1952	-	0	38	R1	-	-	6.01	-	-
1953	-	0	38	R1	-	-	6.35	-	-
1954	-	0	38	R1	-	-	6.70	-	-
1955	-	0	38	R1	-	-	7.05	-	-
1956	2,153	0	38	R1	57	-	7.41	-	420
1957	-	0	38	R1	-	-	7.78	-	-
1958	92	0	38	R1	2	-	8.16	-	20
1959	2,000	0	38	R1	53	-	8.54	-	449
1960	339	0	38	R1	9	-	8.93	-	80
1961	250	0	38	R1	7	-	9.32	-	61
1962	604	0	38	R1	16	-	9.73	-	155
1963	-	0	38	R1	-	-	10.14	-	-
1964	707	0	38	R1	19	-	10.56	-	196
1965	395	0	38	R1	10	-	10.98	-	114
1966	1,926	0	38	R1	51	-	11.42	-	579
1967	472	0	38	R1	12	-	11.86	-	147
1968	-	0	38	R1	-	-	12.31	-	-
1969	-	0	38	R1	-	-	12.77	-	-
1970	-	0	38	R1	-	-	13.24	-	-
1971	-	0	38	R1	-	-	13.72	-	-
1972	-	0	38	R1	-	-	14.20	-	-
1973	446	0	38	R1	12	-	14.70	-	172
1974	844	0	38	R1	22	-	15.20	-	338
1975	4,930	0	38	R1	130	-	15.71	-	2,039
1976	-	0	38	R1	-	-	16.24	-	-
1977	(805)	0	38	R1	(21)	-	16.77	-	(355)
1978	-	0	38	R1	-	-	17.31	-	-
1979	-	0	38	R1	-	-	17.86	-	-

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
366 -- Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1980	-	0	38	R1	-	-	18.42	-	-
1981	-	0	38	R1	-	-	18.99	-	-
1982	-	0	38	R1	-	-	19.56	-	-
1983	-	0	38	R1	-	-	20.15	-	-
1984	20,275	0	38	R1	534	-	20.74	-	11,067
1985	3,682	0	38	R1	97	-	21.35	-	2,068
1986	22,873	0	38	R1	602	-	21.96	-	13,217
1987	6,415	0	38	R1	169	-	22.58	-	3,811
1988	44,102	0	38	R1	1,161	-	23.20	-	26,930
1989	6,213	0	38	R1	164	-	23.84	-	3,898
1990	3,904	0	38	R1	103	-	24.48	-	2,515
1991	-	0	38	R1	-	-	25.13	-	-
1992	1,378	0	38	R1	36	-	25.78	-	935
1993	11,471	0	38	R1	302	-	26.44	-	7,982
1994	1,938	0	38	R1	51	-	27.11	-	1,382
1995	-	0	38	R1	-	-	27.78	-	-
1996	-	0	38	R1	-	-	28.45	-	-
1997	6,959	0	38	R1	183	-	29.13	-	5,335
1998	-	0	38	R1	-	-	29.81	-	-
1999	-	0	38	R1	-	-	30.50	-	-
2000	14,791	0	38	R1	389	-	31.19	-	12,141
2001	11,358	0	38	R1	299	-	31.89	-	9,531
2002	-	0	38	R1	-	-	32.59	-	-
2003	-	0	38	R1	-	-	33.29	-	-
2004	4,838	0	38	R1	127	-	34.00	-	4,329
2005	-	0	38	R1	-	-	34.72	-	-
2006	29,306	0	38	R1	771	-	35.44	-	27,328
2007	17,950	0	38	R1	472	-	36.16	-	17,082
2008	2,968	0	38	R1	78	-	36.89	-	2,882
2009	42,476	0	38	R1	1,118	-	37.63	-	42,063
	267,451	-			7,038	-	28.27		198,940
				Average Remaining Life					28.3

Survivor Curve	R1
ASL	38

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
367 -- Transmission Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	35	L0	-	-	11.87	-	-
1941	-	0	35	L0	-	-	12.06	-	-
1942	-	0	35	L0	-	-	12.26	-	-
1943	-	0	35	L0	-	-	12.46	-	-
1944	-	0	35	L0	-	-	12.66	-	-
1945	-	0	35	L0	-	-	12.86	-	-
1946	-	0	35	L0	-	-	13.06	-	-
1947	-	0	35	L0	-	-	13.27	-	-
1948	-	0	35	L0	-	-	13.48	-	-
1949	-	0	35	L0	-	-	13.69	-	-
1950	-	0	35	L0	-	-	13.91	-	-
1951	61,761	0	35	L0	1,765	-	14.13	-	24,929
1952	-	0	35	L0	-	-	14.35	-	-
1953	-	0	35	L0	-	-	14.57	-	-
1954	8,944	0	35	L0	256	-	14.80	-	3,781
1955	95,433	0	35	L0	2,727	-	15.02	-	40,965
1956	153,043	0	35	L0	4,373	-	15.25	-	66,704
1957	2,766	0	35	L0	79	-	15.49	-	1,224
1958	40,731	0	35	L0	1,164	-	15.73	-	18,300
1959	209,986	0	35	L0	6,000	-	15.97	-	95,784
1960	443,547	0	35	L0	12,673	-	16.21	-	205,398
1961	-	0	35	L0	-	-	16.45	-	-
1962	11,049	0	35	L0	316	-	16.70	-	5,273
1963	5,069	0	35	L0	145	-	16.95	-	2,456
1964	43,691	0	35	L0	1,248	-	17.21	-	21,484
1965	401,158	0	35	L0	11,462	-	17.47	-	200,222
1966	185,675	0	35	L0	5,305	-	17.73	-	94,063
1967	42,318	0	35	L0	1,209	-	18.00	-	21,759
1968	570,758	0	35	L0	16,307	-	18.27	-	297,864
1969	10,242	0	35	L0	293	-	18.54	-	5,425
1970	30,291	0	35	L0	865	-	18.81	-	16,283
1971	390,160	0	35	L0	11,147	-	19.09	-	212,857
1972	220,046	0	35	L0	6,287	-	19.38	-	121,834
1973	20,159	0	35	L0	576	-	19.67	-	11,327
1974	155,219	0	35	L0	4,435	-	19.96	-	88,511
1975	1,038,377	0	35	L0	29,668	-	20.25	-	600,890
1976	667,139	0	35	L0	19,061	-	20.55	-	391,777
1977	32,582	0	35	L0	931	-	20.86	-	19,417
1978	351,269	0	35	L0	10,036	-	21.17	-	212,429
1979	157,163	0	35	L0	4,490	-	21.48	-	96,448

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
367 -- Transmission Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1980	637,037	0	35	L0	18,201	-	21.80	-	396,709
1981	94,865	0	35	L0	2,710	-	22.12	-	59,948
1982	67,797	0	35	L0	1,937	-	22.44	-	43,475
1983	100,369	0	35	L0	2,868	-	22.77	-	65,311
1984	124,371	0	35	L0	3,553	-	23.11	-	82,122
1985	920,732	0	35	L0	26,307	-	23.45	-	616,917
1986	656,696	0	35	L0	18,763	-	23.80	-	446,488
1987	419,996	0	35	L0	12,000	-	24.15	-	289,763
1988	407,419	0	35	L0	11,641	-	24.50	-	285,226
1989	1,403,591	171586	35	L0	40,103	4,902	24.86	-	997,103
1990	409,629	0	35	L0	11,704	-	25.23	-	295,285
1991	475,208	114998	35	L0	13,577	3,286	25.60	-	347,605
1992	770,645	0	35	L0	22,018	-	25.98	-	572,018
1993	1,311,531	0	35	L0	37,472	-	26.36	-	987,845
1994	1,842,857	172928	35	L0	52,653	4,941	26.75	-	1,408,558
1995	2,576,777	0	35	L0	73,622	-	27.15	-	1,998,799
1996	2,206,080	0	35	L0	63,031	-	27.56	-	1,736,906
1997	983,281	0	35	L0	28,094	-	27.97	-	785,897
1998	1,073,527	0	35	L0	30,672	-	28.40	-	871,202
1999	664,955	4126412	35	L0	18,999	117,897	28.85	22.44	3,194,111
2000	1,951,563	0	35	L0	55,759	-	29.30	-	1,633,968
2001	710,776	0	35	L0	20,308	-	29.78	-	604,735
2002	3,267,444	0	35	L0	93,356	-	30.27	-	2,825,968
2003	4,131,461	0	35	L0	118,042	-	30.78	-	3,633,861
2004	1,777,954	0	35	L0	50,799	-	31.32	-	1,591,106
2005	767,710	0	35	L0	21,935	-	31.89	-	699,417
2006	3,695,479	0	35	L0	105,585	-	32.48	-	3,429,786
2007	23,029	0	35	L0	658	-	33.12	-	21,792
2008	422,077	0	35	L0	12,059	-	33.81	-	407,704
2009	584,129	0	35	L0	16,689	-	34.57	-	576,954
	39,827,561	4,585,924			1,137,930	131,026	29.69		33,783,981

Average Remaining Life 26.6

Survivor Curve	L0
ASL	35

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
368 -- Compressor Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	32	L2	-	-	3.90	-	-
1941	-	0	32	L2	-	-	4.09	-	-
1942	-	0	32	L2	-	-	4.29	-	-
1943	-	0	32	L2	-	-	4.48	-	-
1944	-	0	32	L2	-	-	4.67	-	-
1945	-	0	32	L2	-	-	4.87	-	-
1946	-	0	32	L2	-	-	5.07	-	-
1947	-	0	32	L2	-	-	5.27	-	-
1948	-	0	32	L2	-	-	5.48	-	-
1949	-	0	32	L2	-	-	5.68	-	-
1950	-	0	32	L2	-	-	5.89	-	-
1951	-	0	32	L2	-	-	6.11	-	-
1952	-	0	32	L2	-	-	6.32	-	-
1953	-	0	32	L2	-	-	6.54	-	-
1954	-	0	32	L2	-	-	6.76	-	-
1955	-	0	32	L2	-	-	6.98	-	-
1956	-	0	32	L2	-	-	7.21	-	-
1957	-	0	32	L2	-	-	7.44	-	-
1958	-	0	32	L2	-	-	7.67	-	-
1959	-	0	32	L2	-	-	7.91	-	-
1960	-	0	32	L2	-	-	8.14	-	-
1961	794	0	32	L2	25	-	8.39	-	208
1962	11,090	0	32	L2	347	-	8.63	-	2,991
1963	89,639	0	32	L2	2,801	-	8.88	-	24,868
1964	2,757	0	32	L2	86	-	9.13	-	786
1965	76,220	0	32	L2	2,382	-	9.38	-	22,334
1966	1,010	0	32	L2	32	-	9.63	-	304
1967	1,745	0	32	L2	55	-	9.88	-	539
1968	-	0	32	L2	-	-	10.13	-	-
1969	3,869	0	32	L2	121	-	10.38	-	1,255
1970	480	0	32	L2	15	-	10.63	-	160
1971	23,086	0	32	L2	721	-	10.88	-	7,851
1972	309	0	32	L2	10	-	11.13	-	107
1973	-	0	32	L2	-	-	11.38	-	-
1974	958	0	32	L2	30	-	11.62	-	348
1975	57,007	0	32	L2	1,781	-	11.86	-	21,126
1976	43,971	0	32	L2	1,374	-	12.10	-	16,625
1977	-	0	32	L2	-	-	12.34	-	-

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
368 -- Compressor Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1978	600	0	32	L2	19	-	12.58	-	236
1979	14,111	0	32	L2	441	-	12.82	-	5,653
1980	12,740	0	32	L2	398	-	13.07	-	5,202
1981	1,020	0	32	L2	32	-	13.32	-	424
1982	640	0	32	L2	20	-	13.58	-	272
1983	-	0	32	L2	-	-	13.85	-	-
1984	483,934	0	32	L2	15,123	-	14.13	-	213,748
1985	77,490	0	32	L2	2,422	-	14.44	-	34,960
1986	397,226	0	32	L2	12,413	-	14.76	-	183,230
1987	42,436	0	32	L2	1,326	-	15.11	-	20,037
1988	-	0	32	L2	-	-	15.49	-	-
1989	11,796	0	32	L2	369	-	15.89	-	5,859
1990	-	0	32	L2	-	-	16.34	-	-
1991	190,334	0	32	L2	5,948	-	16.82	-	100,056
1992	12,181	0	32	L2	381	-	17.35	-	6,604
1993	(2)	0	32	L2	(0)	-	17.92	-	(1)
1994	8,004	0	32	L2	250	-	18.54	-	4,636
1995	-	0	32	L2	-	-	19.20	-	-
1996	-	0	32	L2	-	-	19.91	-	-
1997	-	0	32	L2	-	-	20.66	-	-
1998	8,440	0	32	L2	264	-	21.44	-	5,656
1999	-	519600	32	L2	-	16,238	22.26	-	-
2000	26,345	0	32	L2	823	-	23.09	-	19,013
2001	-	0	32	L2	-	-	23.95	-	-
2002	6,075	0	32	L2	190	-	24.83	-	4,713
2003	443,449	0	32	L2	13,858	-	25.73	-	356,510
2004	17,735	0	32	L2	554	-	26.65	-	14,767
2005	-	0	32	L2	-	-	27.58	-	-
2006	827,361	0	32	L2	25,855	-	28.54	-	737,954
2007	2,407,136	0	32	L2	75,223	-	29.52	-	2,220,298
2008	242,933	0	32	L2	7,592	-	30.50	-	231,573
2009	2,475,742	0	32	L2	77,367	-	31.50		2,437,070
	8,020,661	519,600			250,646	16,238	26.76		6,707,974

Average Remaining Life 25.1

Survivor Curve L2
ASL 32

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
369 -- Measuring Regulating Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	26	L0	-	-	5.78	-	-
1941	-	0	26	L0	-	-	5.93	-	-
1942	-	0	26	L0	-	-	6.08	-	-
1943	-	0	26	L0	-	-	6.24	-	-
1944	-	0	26	L0	-	-	6.39	-	-
1945	-	0	26	L0	-	-	6.55	-	-
1946	-	0	26	L0	-	-	6.71	-	-
1947	-	0	26	L0	-	-	6.88	-	-
1948	-	0	26	L0	-	-	7.04	-	-
1949	-	0	26	L0	-	-	7.21	-	-
1950	-	0	26	L0	-	-	7.38	-	-
1951	604	0	26	L0	23	-	7.56	-	176
1952	-	0	26	L0	-	-	7.73	-	-
1953	-	0	26	L0	-	-	7.91	-	-
1954	-	0	26	L0	-	-	8.09	-	-
1955	2,821	0	26	L0	109	-	8.28	-	898
1956	3,317	0	26	L0	128	-	8.46	-	1,080
1957	1,730	0	26	L0	67	-	8.65	-	576
1958	4,222	0	26	L0	162	-	8.84	-	1,436
1959	11,640	0	26	L0	448	-	9.04	-	4,046
1960	36,436	0	26	L0	1,401	-	9.24	-	12,943
1961	2,350	0	26	L0	90	-	9.44	-	853
1962	143	0	26	L0	6	-	9.64	-	53
1963	1,590	0	26	L0	61	-	9.85	-	602
1964	2,469	0	26	L0	95	-	10.06	-	955
1965	11,196	0	26	L0	431	-	10.27	-	4,423
1966	12,600	0	26	L0	485	-	10.49	-	5,083
1967	6,054	0	26	L0	233	-	10.71	-	2,493
1968	5,943	0	26	L0	229	-	10.93	-	2,499
1969	18,946	0	26	L0	729	-	11.16	-	8,132
1970	4,457	0	26	L0	171	-	11.39	-	1,953
1971	22,690	0	26	L0	873	-	11.63	-	10,146
1972	1,848	0	26	L0	71	-	11.87	-	843
1973	11,003	0	26	L0	423	-	12.11	-	5,124
1974	21,450	0	26	L0	825	-	12.36	-	10,194
1975	68,977	0	26	L0	2,653	-	12.61	-	33,449
1976	25,972	0	26	L0	999	-	12.86	-	12,850
1977	5,860	0	26	L0	225	-	13.12	-	2,958
1978	2,125	0	26	L0	82	-	13.39	-	1,094

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
369 -- Measuring Regulating Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	11,949	0	26	L0	460	-	13.66	-	6,278
1980	4,539	0	26	L0	175	-	13.93	-	2,433
1981	2,096	0	26	L0	81	-	14.21	-	1,146
1982	2,119	0	26	L0	82	-	14.50	-	1,182
1983	11,231	0	26	L0	432	-	14.79	-	6,389
1984	93,670	0	26	L0	3,603	-	15.09	-	54,350
1985	40,669	0	26	L0	1,564	-	15.39	-	24,068
1986	4,156	0	26	L0	160	-	15.69	-	2,509
1987	1,551	0	26	L0	60	-	16.01	-	955
1988	14,728	0	26	L0	566	-	16.33	-	9,248
1989	65,410	23055	26	L0	2,516	887	16.65	-	41,889
1990	40,717	0	26	L0	1,566	-	16.98	-	26,594
1991	39,795	0	26	L0	1,531	-	17.32	-	26,509
1992	43,190	0	26	L0	1,661	-	17.66	-	29,342
1993	44,138	0	26	L0	1,698	-	18.02	-	30,583
1994	37,008	0	26	L0	1,423	-	18.37	-	26,152
1995	11,055	0	26	L0	425	-	18.74	-	7,967
1996	19,636	0	26	L0	755	-	19.11	-	14,433
1997	138,952	0	26	L0	5,344	-	19.49	-	104,165
1998	198,341	0	26	L0	7,629	-	19.88	-	151,650
1999	363,028	163168	26	L0	13,963	6,276	20.28	-	283,146
2000	185,729	0	26	L0	7,143	-	20.69	-	147,808
2001	84,508	0	26	L0	3,250	-	21.12	-	68,645
2002	184,938	0	26	L0	7,113	-	21.57	-	153,397
2003	78,872	0	26	L0	3,034	-	22.03	-	66,837
2004	146,005	0	26	L0	5,616	-	22.52	-	126,484
2005	249,689	0	26	L0	9,603	-	23.04	-	221,296
2006	219,987	0	26	L0	8,461	-	23.60	-	199,656
2007	409,207	0	39	L0	10,492.49	-	37.10	-	389,227
2008	103,098	0	39	L0	2,644	-	37.80	-	99,915
2009	207,408	0	39	L0	5,318	-	38.57	-	205,108
	3,343,861	186,223			119,383	7,162	22.23		2,654,219
									21

Average Remaining Life

Survivor Curve	L0
ASL	26

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	35	L3	-	-	2.77	-	-
1941	-	0	35	L3	-	-	2.97	-	-
1942	-	0	35	L3	-	-	3.17	-	-
1943	-	0	35	L3	-	-	3.37	-	-
1944	-	0	35	L3	-	-	3.58	-	-
1945	-	0	35	L3	-	-	3.79	-	-
1946	-	0	35	L3	-	-	4.01	-	-
1947	-	0	35	L3	-	-	4.22	-	-
1948	-	0	35	L3	-	-	4.44	-	-
1949	-	0	35	L3	-	-	4.67	-	-
1950	-	0	35	L3	-	-	4.89	-	-
1951	400	0	35	L3	11	-	5.12	-	59
1952	-	0	35	L3	-	-	5.36	-	-
1953	-	0	35	L3	-	-	5.59	-	-
1954	-	0	35	L3	-	-	5.83	-	-
1955	1,480	0	35	L3	42	-	6.08	-	257
1956	3,602	0	35	L3	103	-	6.33	-	651
1957	814	0	35	L3	23	-	6.58	-	153
1958	199	0	35	L3	6	-	6.83	-	39
1959	500	0	35	L3	14	-	7.09	-	101
1960	488	0	35	L3	14	-	7.35	-	102
1961	1,719	0	35	L3	49	-	7.61	-	374
1962	-	0	35	L3	-	-	7.87	-	-
1963	-	0	35	L3	-	-	8.13	-	-
1964	264	0	35	L3	8	-	8.38	-	63
1965	-	0	35	L3	-	-	8.63	-	-
1966	4,386	0	35	L3	125	-	8.87	-	1,112
1967	2,857	0	35	L3	82	-	9.11	-	743
1968	798	0	35	L3	23	-	9.33	-	213
1969	64	0	35	L3	2	-	9.54	-	17
1970	19,796	0	35	L3	566	-	9.74	-	5,506
1971	1,439	0	35	L3	41	-	9.92	-	408

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1972	366	0	35	L3	10	-	10.10	-	106
1973	-	0	35	L3	-	-	10.27	-	-
1974	298	0	35	L3	9	-	10.43	-	89
1975	414	0	35	L3	12	-	10.60	-	125
1976	4,664	0	35	L3	133	-	10.77	-	1,436
1977	16,625	0	35	L3	475	-	10.96	-	5,206
1978	-	0	35	L3	-	-	11.17	-	-
1979	2,354	0	35	L3	67	-	11.40	-	767
1980	572	0	35	L3	16	-	11.67	-	191
1981	1,270	0	35	L3	36	-	11.97	-	434
1982	-	0	35	L3	-	-	12.31	-	-
1983	734	0	35	L3	21	-	12.70	-	266
1984	-	0	35	L3	-	-	13.14	-	-
1985	9,863	0	35	L3	282	-	13.63	-	3,841
1986	6,484	0	35	L3	185	-	14.17	-	2,625
1987	-	0	35	L3	-	-	14.77	-	-
1988	5,063	0	35	L3	145	-	15.41	-	2,229
1989	2,806	0	35	L3	80	-	16.10	-	1,291
1990	779	0	35	L3	22	-	16.84	-	375
1991	-	0	35	L3	-	-	17.61	-	-
1992	7,442	0	35	L3	213	-	18.42	-	3,916
1993	3,144	0	35	L3	90	-	19.25	-	1,729
1994	-	0	35	L3	-	-	20.11	-	-
1995	12,893	0	35	L3	368	-	20.98	-	7,729
1996	3,942	0	35	L3	113	-	21.88	-	2,464
1997	4,101	0	35	L3	117	-	22.78	-	2,670
1998	2,265	0	35	L3	65	-	23.71	-	1,534
1999	3,538	0	35	L3	101	-	24.65	-	2,491
2000	-	0	35	L3	-	-	25.60	-	-
2001	5,172	0	35	L3	148	-	26.56	-	3,925
2002	2,756	0	35	L3	79	-	27.53	-	2,168
2003	2,624	0	35	L3	75	-	28.52	-	2,138
2004	2,883	0	35	L3	82	-	29.51	-	2,430

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
2005	1,850	0	35	L3	53	-	30.50	-	1,612
2006	-	0	35	L3	-	-	31.50	-	-
2007	-	0	35	L3	-	-	32.50	-	-
2008	-	0	35	L3	-	-	33.50	-	-
2009	-	0	35	L3	-	-	34.50	-	-
	143,708	-			4,106	-	15.49		63,586
				Average Remaining Life					15.49

Survivor Curve	L3
ASL	35

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
376 -- Distribution Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	58,962	0	34	R2	1,734	-	-	-	-
1941	-	0	34	R2	-	-	-	-	-
1942	-	0	34	R2	-	-	-	-	-
1943	-	0	34	R2	-	-	-	-	-
1944	-	0	34	R2	-	-	-	-	-
1945	-	0	34	R2	-	-	-	-	-
1946	-	0	34	R2	-	-	0.50	-	-
1947	75,766	0	34	R2	2,228	-	0.50	-	1,114
1948	67,865	0	34	R2	1,996	-	0.56	-	1,126
1949	62,008	0	34	R2	1,824	-	0.77	-	1,400
1950	29,854	0	34	R2	878	-	1.01	-	883
1951	36,626	0	34	R2	1,077	-	1.26	-	1,357
1952	18,609	0	34	R2	547	-	1.52	-	834
1953	12,981	0	34	R2	382	-	1.80	-	686
1954	47,353	0	34	R2	1,393	-	2.07	-	2,889
1955	148,499	0	34	R2	4,368	-	2.36	-	10,292
1956	143,937	0	34	R2	4,233	-	2.64	-	11,184
1957	39,727	0	34	R2	1,168	-	2.93	-	3,422
1958	34,326	0	34	R2	1,010	-	3.22	-	3,248
1959	106,509	0	34	R2	3,133	-	3.51	-	10,986
1960	69,660	0	34	R2	2,049	-	3.80	-	7,781
1961	110,606	0	34	R2	3,253	-	4.09	-	13,308
1962	71,538	0	34	R2	2,104	-	4.39	-	9,231
1963	86,884	0	34	R2	2,555	-	4.69	-	11,980
1964	89,514	0	34	R2	2,633	-	5.00	-	13,152
1965	123,728	0	34	R2	3,639	-	5.31	-	19,325
1966	135,264	0	34	R2	3,978	-	5.63	-	22,418
1967	317,430	0	34	R2	9,336	-	5.97	-	55,741
1968	182,038	0	34	R2	5,354	-	6.32	-	33,827
1969	582,335	0	34	R2	17,128	-	6.68	-	114,398
1970	1,455,571	0	34	R2	42,811	-	7.05	-	302,022
1971	1,074,050	0	34	R2	31,590	-	7.45	-	235,207
1972	324,850	0	34	R2	9,554	-	7.85	-	75,027
1973	448,840	0	34	R2	13,201	-	8.28	-	109,254
1974	294,232	0	34	R2	8,654	-	8.72	-	75,432
1975	409,344	0	34	R2	12,040	-	9.17	-	110,455
1976	201,118	0	34	R2	5,915	-	9.65	-	57,080
1977	215,318	0	34	R2	6,333	-	10.14	-	64,231
1978	316,671	0	34	R2	9,314	-	10.65	-	99,220

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
376 -- Distribution Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	723,822	0	34	R2	21,289	-	11.18	-	238,028
1980	646,465	0	34	R2	19,014	-	11.73	-	222,956
1981	1,960,024	0	34	R2	57,648	-	12.29	-	708,402
1982	1,666,448	0	34	R2	49,013	-	12.87	-	630,683
1983	1,579,871	0	34	R2	46,467	-	13.46	-	625,596
1984	1,436,971	0	34	R2	42,264	-	14.08	-	594,871
1985	1,581,605	0	34	R2	46,518	-	14.70	-	683,943
1986	1,840,623	0	34	R2	54,136	-	15.35	-	830,766
1987	1,938,634	0	34	R2	57,019	-	16.00	-	912,529
1988	2,392,247	0	34	R2	70,360	-	16.68	-	1,173,382
1989	2,519,548	0	34	R2	74,104	-	17.36	-	1,286,730
1990	2,464,496	0	34	R2	72,485	-	18.06	-	1,309,414
1991	3,124,355	0	34	R2	91,893	-	18.78	-	1,725,641
1992	2,153,634	0	34	R2	63,342	-	19.51	-	1,235,564
1993	2,518,971	0	34	R2	74,087	-	20.25	-	1,499,990
1994	2,398,105	0	34	R2	70,533	-	21.00	-	1,481,086
1995	3,191,099	0	34	R2	93,856	-	21.76	-	2,042,589
1996	2,627,094	0	34	R2	77,267	-	22.54	-	1,741,541
1997	2,772,515	1000	34	R2	81,545	29	23.33	7.45	1,902,372
1998	4,460,035	0	34	R2	131,178	-	24.12	-	3,164,656
1999	3,295,415	0	34	R2	96,924	-	24.93	-	2,416,718
2000	3,191,898	0	34	R2	93,879	-	25.75	-	2,417,744
2001	1,634,379	6556	34	R2	48,070	193	26.58	24.93	1,282,672
2002	1,118,713	0	34	R2	32,903	-	27.42	-	902,304
2003	1,493,803	0	34	R2	43,935	-	28.27	-	1,242,135
2004	1,866,444	0	34	R2	54,895	-	29.13	-	1,599,104
2005	1,634,459	0	34	R2	48,072	-	30.00	-	1,442,028
2006	1,344,632	0	34	R2	39,548	-	30.87	-	1,220,952
2007	1,099,901	0	34	R2	32,350	-	31.76	-	1,027,324
2008	2,210,012	0	34	R2	65,000	-	32.65	-	2,122,153
2009	1,821,352	0	34	R2	53,569	-	33.55	-	1,797,127
	72,099,583	7,556			2,120,576	222	20.26		42,959,510

Average Remaining Life 20.3

Survivor Curve	R2
ASL	34

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
378 -- Measuring Regulating Equipment - General

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	110	0	30	L0	4	-	8.37	-	31
1941	-	0	30	L0	-	-	8.54	-	-
1942	-	0	30	L0	-	-	8.72	-	-
1943	-	0	30	L0	-	-	8.89	-	-
1944	-	0	30	L0	-	-	9.07	-	-
1945	-	0	30	L0	-	-	9.25	-	-
1946	-	0	30	L0	-	-	9.43	-	-
1947	-	0	30	L0	-	-	9.62	-	-
1948	260	0	30	L0	9	-	9.81	-	85
1949	97	0	30	L0	3	-	9.99	-	32
1950	202	0	30	L0	7	-	10.19	-	69
1951	535	0	30	L0	18	-	10.38	-	185
1952	904	0	30	L0	30	-	10.58	-	319
1953	789	0	30	L0	26	-	10.78	-	283
1954	38	0	30	L0	1	-	10.98	-	14
1955	5,199	0	30	L0	173	-	11.18	-	1,938
1956	3,855	0	30	L0	129	-	11.39	-	1,464
1957	1,094	0	30	L0	36	-	11.60	-	423
1958	-	0	30	L0	-	-	11.82	-	-
1959	12,372	0	30	L0	412	-	12.03	-	4,962
1960	-	0	30	L0	-	-	12.25	-	-
1961	-	0	30	L0	-	-	12.47	-	-
1962	321	0	30	L0	11	-	12.70	-	136
1963	-	0	30	L0	-	-	12.93	-	-
1964	608	0	30	L0	20	-	13.16	-	267
1965	881	0	30	L0	29	-	13.40	-	393
1966	5,272	0	30	L0	176	-	13.63	-	2,396
1967	-	0	30	L0	-	-	13.88	-	-
1968	317	0	30	L0	11	-	14.12	-	149
1969	281	0	30	L0	9	-	14.37	-	135
1970	23,330	0	30	L0	778	-	14.62	-	11,373
1971	24,948	0	30	L0	832	-	14.88	-	12,376
1972	13,981	0	30	L0	466	-	15.14	-	7,057
1973	3,975	0	30	L0	133	-	15.41	-	2,041
1974	5,207	0	30	L0	174	-	15.68	-	2,721
1975	6,244	0	30	L0	208	-	15.95	-	3,320
1976	3,610	0	30	L0	120	-	16.23	-	1,953
1977	8,552	0	30	L0	285	-	16.51	-	4,706
1978	7,190	0	30	L0	240	-	16.80	-	4,025
1979	9,000	0	30	L0	300	-	17.09	-	5,126

Delta Natural Gas Company
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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1980	41,132	0	30	L0	1,371	-	17.38	-	23,833
1981	51,901	0	30	L0	1,730	-	17.68	-	30,592
1982	13,595	0	30	L0	453	-	17.99	-	8,152
1983	20,919	0	30	L0	697	-	18.30	-	12,760
1984	16,759	0	30	L0	559	-	18.61	-	10,399
1985	12,417	0	30	L0	414	-	18.94	-	7,837
1986	37,728	0	30	L0	1,258	-	19.26	-	24,224
1987	54,661	0	30	L0	1,822	-	19.59	-	35,700
1988	57,764	0	30	L0	1,925	-	19.93	-	38,376
1989	87,102	0	30	L0	2,903	-	20.27	-	58,863
1990	51,068	0	30	L0	1,702	-	20.62	-	35,105
1991	44,062	0	30	L0	1,469	-	20.98	-	30,810
1992	52,625	0	30	L0	1,754	-	21.34	-	37,431
1993	49,956	0	30	L0	1,665	-	21.71	-	36,144
1994	44,296	0	30	L0	1,477	-	22.08	-	32,601
1995	101,062	0	30	L0	3,369	-	22.46	-	75,659
1996	58,206	0	30	L0	1,940	-	22.85	-	44,327
1997	116,218	0	30	L0	3,874	-	23.24	-	90,041
1998	62,585	0	30	L0	2,086	-	23.65	-	49,337
1999	133,573	0	30	L0	4,452	-	24.07	-	107,167
2000	8,746	0	30	L0	292	-	24.50	-	7,143
2001	27,018	0	30	L0	901	-	24.95	-	22,473
2002	14,796	0	30	L0	493	-	25.42	-	12,538
2003	132,610	0	30	L0	4,420	-	25.91	-	114,536
2004	59,940	0	30	L0	1,998	-	26.42	-	52,797
2005	117,525	0	30	L0	3,918	-	26.97	-	105,640
2006	21,873	0	30	L0	729	-	27.54	-	20,080
2007	-	0	30	L0	-	-	28.16	-	-
2008	48,697	0	30	L0	1,623	-	28.83	-	46,792
2009	14,183	0	30	L0	473	-	29.57	-	13,981
	1,692,189	-			56,406	-	22.22		1,253,319

Average Remaining Life 22.2

Survivor Curve	L0
ASL	30

Delta Natural Gas Company
Depreciation Study
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379 -- Measuring Regulating Station Equipment -- City Gate

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	40	R1	-	-	3.51	-	-
1941	-	0	40	R1	-	-	3.80	-	-
1942	-	0	40	R1	-	-	4.10	-	-
1943	-	0	40	R1	-	-	4.41	-	-
1944	-	0	40	R1	-	-	4.71	-	-
1945	-	0	40	R1	-	-	5.03	-	-
1946	-	0	40	R1	-	-	5.35	-	-
1947	-	0	40	R1	-	-	5.67	-	-
1948	-	0	40	R1	-	-	6.00	-	-
1949	-	0	40	R1	-	-	6.33	-	-
1950	626	0	40	R1	16	-	6.68	-	104
1951	498	0	40	R1	12	-	7.02	-	87
1952	-	0	40	R1	-	-	7.38	-	-
1953	-	0	40	R1	-	-	7.74	-	-
1954	424	0	40	R1	11	-	8.10	-	86
1955	4,368	0	40	R1	109	-	8.48	-	925
1956	6,252	0	40	R1	156	-	8.85	-	1,384
1957	2,928	0	40	R1	73	-	9.24	-	676
1958	415	0	40	R1	10	-	9.63	-	100
1959	1,136	0	40	R1	28	-	10.03	-	285
1960	5,188	0	40	R1	130	-	10.44	-	1,354
1961	729	0	40	R1	18	-	10.86	-	198
1962	103	0	40	R1	3	-	11.28	-	29
1963	-	0	40	R1	-	-	11.71	-	-
1964	118	0	40	R1	3	-	12.14	-	36
1965	185	0	40	R1	5	-	12.59	-	58
1966	10,334	0	40	R1	258	-	13.04	-	3,369
1967	1,607	0	40	R1	40	-	13.50	-	543
1968	13	0	40	R1	0	-	13.97	-	5
1969	1,756	0	40	R1	44	-	14.45	-	634
1970	6,102	0	40	R1	153	-	14.94	-	2,279

Delta Natural Gas Company
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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1971	-	0	40	R1	-	-	15.43	-	-
1972	-	0	40	R1	-	-	15.93	-	-
1973	-	0	40	R1	-	-	16.45	-	-
1974	1,289	0	40	R1	32	-	16.97	-	547
1975	-	0	40	R1	-	-	17.50	-	-
1976	1,180	0	40	R1	30	-	18.03	-	532
1977	9,218	0	40	R1	230	-	18.58	-	4,282
1978	1,634	0	40	R1	41	-	19.13	-	782
1979	32,008	0	40	R1	800	-	19.70	-	15,763
1980	43,580	0	40	R1	1,090	-	20.27	-	22,086
1981	10,544	0	40	R1	264	-	20.85	-	5,497
1982	-	0	40	R1	-	-	21.44	-	-
1983	14,039	0	40	R1	351	-	22.04	-	7,735
1984	13,765	0	40	R1	344	-	22.65	-	7,793
1985	69,107	0	40	R1	1,728	-	23.26	-	40,184
1986	29,155	0	40	R1	729	-	23.88	-	17,405
1987	41,206	0	40	R1	1,030	-	24.51	-	25,247
1988	-	0	40	R1	-	-	25.14	-	-
1989	-	0	40	R1	-	-	25.78	-	-
1990	-	0	40	R1	-	-	26.43	-	-
1991	33,855	0	40	R1	846	-	27.09	-	22,926
1992	8,924	0	40	R1	223	-	27.75	-	6,190
1993	19,002	0	40	R1	475	-	28.41	-	13,497
1994	37,494	0	40	R1	937	-	29.08	-	27,258
1995	13,865	0	40	R1	347	-	29.75	-	10,313
1996	-	0	40	R1	-	-	30.43	-	-
1997	2,853	0	40	R1	71	-	31.11	-	2,219
1998	-	0	40	R1	-	-	31.80	-	-
1999	14,844	0	40	R1	371	-	32.49	-	12,056
2000	-	0	40	R1	-	-	33.18	-	-
2001	-	0	40	R1	-	-	33.88	-	-
2002	13,763	0	40	R1	344	-	34.58	-	11,898

Delta Natural Gas Company
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379 -- Measuring Regulating Station Equipment -- City Gate

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
2003	-	0	40	R1	-	-	35.29	-	-
2004	79,594	0	40	R1	1,990	-	36.00	-	71,628
2005	19,922	0	40	R1	498	-	36.71	-	18,285
2006	17,058	0	40	R1	426	-	37.43	-	15,963
2007	-	0	40	R1	-	-	38.16	-	-
2008	-	0	40	R1	-	-	38.89	-	-
2009	25,045	0	40	R1	626	-	39.63	-	24,813
	595,726	-			14,893	-	26.66		397,051
					Average Remaining Life				26.7

Survivor Curve R1
ASL 40

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
381 -- Meters

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	1,300	0	36	S4	36	-	-	-	-
1941	-	0	36	S4	-	-	-	-	-
1942	-	0	36	S4	-	-	-	-	-
1943	-	0	36	S4	-	-	-	-	-
1944	-	0	36	S4	-	-	-	-	-
1945	-	0	36	S4	-	-	-	-	-
1946	-	0	36	S4	-	-	0.50	-	-
1947	1,361	0	36	S4	38	-	0.50	-	19
1948	7,200	0	36	S4	200	-	1.03	-	205
1949	12,983	0	36	S4	361	-	0.99	-	357
1950	11,515	0	36	S4	320	-	0.93	-	298
1951	8,282	0	36	S4	230	-	0.95	-	219
1952	25,195	0	36	S4	700	-	1.01	-	710
1953	4,329	0	36	S4	120	-	1.10	-	132
1954	6,163	0	36	S4	171	-	1.19	-	204
1955	14,171	0	36	S4	394	-	1.29	-	509
1956	29,813	0	36	S4	828	-	1.40	-	1,160
1957	15,293	0	36	S4	425	-	1.52	-	644
1958	17,188	0	36	S4	477	-	1.64	-	782
1959	19,856	0	36	S4	552	-	1.77	-	975
1960	21,145	0	36	S4	587	-	1.91	-	1,119
1961	24,843	0	36	S4	690	-	2.05	-	1,415
1962	14,485	0	36	S4	402	-	2.21	-	887
1963	31,894	0	36	S4	886	-	2.37	-	2,100
1964	18,103	0	36	S4	503	-	2.55	-	1,280
1965	23,944	0	36	S4	665	-	2.73	-	1,818
1966	20,427	0	36	S4	567	-	2.93	-	1,665
1967	36,960	0	36	S4	1,027	-	3.15	-	3,235
1968	44,180	0	36	S4	1,227	-	3.38	-	4,152
1969	61,872	0	36	S4	1,719	-	3.63	-	6,246
1970	219,572	0	36	S4	6,099	-	3.90	-	23,817
1971	210,607	0	36	S4	5,850	-	4.20	-	24,560
1972	91,736	0	36	S4	2,548	-	4.52	-	11,508
1973	91,823	0	36	S4	2,551	-	4.86	-	12,398
1974	58,878	0	36	S4	1,636	-	5.24	-	8,562
1975	78,982	0	36	S4	2,194	-	5.64	-	12,378
1976	48,111	0	36	S4	1,336	-	6.08	-	8,130
1977	66,317	0	36	S4	1,842	-	6.56	-	12,090
1978	67,406	0	36	S4	1,872	-	7.08	-	13,262

Delta Natural Gas Company
Depreciation Study
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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	53,560	0	36	S4	1,488	-	7.65	-	11,374
1980	69,898	0	36	S4	1,942	-	8.25	-	16,021
1981	92,069	0	36	S4	2,557	-	8.90	-	22,771
1982	195,244	0	36	S4	5,423	-	9.60	-	52,071
1983	125,587	0	36	S4	3,489	-	10.34	-	36,085
1984	147,259	0	36	S4	4,091	-	11.13	-	45,527
1985	82,296	0	36	S4	2,286	-	11.96	-	27,333
1986	81,339	0	36	S4	2,259	-	12.82	-	28,967
1987	125,529	0	36	S4	3,487	-	13.72	-	47,831
1988	216,913	0	36	S4	6,025	-	14.64	-	88,219
1989	86,154	0	36	S4	2,393	-	15.59	-	37,305
1990	195,258	0	36	S4	5,424	-	16.55	-	89,776
1991	142,091	0	36	S4	3,947	-	17.53	-	69,187
1992	105,207	6585	36	S4	2,922	183	18.52	-	54,110
1993	281,873	0	36	S4	7,830	-	19.51	-	152,740
1994	239,405	0	36	S4	6,650	-	20.50	-	136,350
1995	297,778	0	36	S4	8,272	-	21.50	-	177,851
1996	1,004,419	0	36	S4	27,901	-	22.50	-	627,776
1997	94,368	0	36	S4	2,621	-	23.50	-	61,602
1998	828,908	0	36	S4	23,025	-	24.50	-	564,119
1999	221,392	0	36	S4	6,150	-	25.50	-	156,819
2000	203,319	0	36	S4	5,648	-	26.50	-	149,665
2001	408,435	0	36	S4	11,345	-	27.50	-	311,999
2002	577,827	0	36	S4	16,051	-	28.50	-	457,447
2003	1,828,445	0	36	S4	50,790	-	29.50	-	1,498,310
2004	92,829	0	36	S4	2,579	-	30.50	-	78,647
2005	215,473	0	36	S4	5,985	-	31.50	-	188,539
2006	225,642	0	36	S4	6,268	-	32.50	-	203,705
2007	275,722	0	36	S4	7,659	-	33.50	-	256,575
2008	149,376	0	36	S4	4,149	-	34.50	-	143,152
2009	82,941	0	36	S4	2,304	-	35.50	-	81,790
	10,152,490	6,585			282,014	183	21.38		6,030,497

Average Remaining Life 21.4

Survivor Curve	S4
ASL	36

Delta Natural Gas Company
Depreciation Study
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382 -- Meter Regulator Installation

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	386	0	32	S1	12	-	-	-	-
1941	-	0	32	S1	-	-	-	-	-
1942	-	0	32	S1	-	-	-	-	-
1943	-	0	32	S1	-	-	-	-	-
1944	-	0	32	S1	-	-	-	-	-
1945	-	0	32	S1	-	-	0.50	-	-
1946	-	0	32	S1	-	-	0.50	-	-
1947	291	0	32	S1	9	-	0.55	-	5
1948	543	0	32	S1	17	-	0.75	-	13
1949	1,057	0	32	S1	33	-	0.99	-	33
1950	1,120	0	32	S1	35	-	1.25	-	44
1951	1,784	0	32	S1	56	-	1.51	-	84
1952	293	0	32	S1	9	-	1.78	-	16
1953	394	0	32	S1	12	-	2.06	-	25
1954	1,666	0	32	S1	52	-	2.34	-	122
1955	2,929	0	32	S1	92	-	2.62	-	240
1956	8,754	0	32	S1	274	-	2.91	-	796
1957	8,202	0	32	S1	256	-	3.20	-	820
1958	6,222	0	32	S1	194	-	3.49	-	679
1959	4,846	0	32	S1	151	-	3.79	-	574
1960	3,986	0	32	S1	125	-	4.09	-	510
1961	3,306	0	32	S1	103	-	4.40	-	455
1962	9,394	0	32	S1	294	-	4.71	-	1,384
1963	1,800	0	32	S1	56	-	5.03	-	283
1964	1,800	0	32	S1	56	-	5.35	-	301
1965	2,280	0	32	S1	71	-	5.68	-	404
1966	2,088	0	32	S1	65	-	6.01	-	392
1967	4,152	0	32	S1	130	-	6.34	-	823
1968	5,823	0	32	S1	182	-	6.69	-	1,217
1969	8,651	0	32	S1	270	-	7.03	-	1,901
1970	8,413	0	32	S1	263	-	7.39	-	1,942
1971	6,017	0	32	S1	188	-	7.75	-	1,457
1972	6,795	0	32	S1	212	-	8.12	-	1,724
1973	8,877	0	32	S1	277	-	8.49	-	2,356
1974	5,641	0	32	S1	176	-	8.87	-	1,564
1975	4,065	0	32	S1	127	-	9.26	-	1,177
1976	2,843	0	32	S1	89	-	9.66	-	859
1977	2,209	0	32	S1	69	-	10.07	-	695
1978	1,604	0	32	S1	50	-	10.49	-	526

Delta Natural Gas Company
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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	4,463	0	32	S1	139	-	10.91	-	1,522
1980	5,200	0	32	S1	163	-	11.35	-	1,844
1981	12,046	0	32	S1	376	-	11.80	-	4,441
1982	66,540	0	32	S1	2,079	-	12.26	-	25,486
1983	99,610	0	32	S1	3,113	-	12.73	-	39,617
1984	94,296	0	32	S1	2,947	-	13.21	-	38,926
1985	67,324	0	32	S1	2,104	-	13.71	-	28,836
1986	69,688	0	32	S1	2,178	-	14.22	-	30,959
1987	60,219	0	32	S1	1,882	-	14.74	-	27,740
1988	71,400	0	32	S1	2,231	-	15.28	-	34,095
1989	89,262	296457	32	S1	2,789	9,264	15.84	-	44,175
1990	147,697	0	32	S1	4,616	-	16.41	-	75,740
1991	118,996	0	32	S1	3,719	-	17.00	-	63,219
1992	170,332	0	32	S1	5,323	-	17.61	-	93,738
1993	142,352	0	32	S1	4,449	-	18.24	-	81,139
1994	160,617	0	32	S1	5,019	-	18.89	-	94,812
1995	148,177	0	32	S1	4,631	-	19.56	-	90,577
1996	150,837	0	32	S1	4,714	-	20.25	-	95,473
1997	149,850	0	32	S1	4,683	-	20.97	-	98,206
1998	172,095	0	32	S1	5,378	-	21.71	-	116,770
1999	155,766	0	32	S1	4,868	-	22.48	-	109,419
2000	122,090	0	32	S1	3,815	-	23.27	-	88,782
2001	98,891	0	32	S1	3,090	-	24.09	-	74,438
2002	93,543	0	32	S1	2,923	-	24.93	-	72,878
2003	102,667	0	32	S1	3,208	-	25.80	-	82,777
2004	112,534	0	32	S1	3,517	-	26.70	-	93,882
2005	110,798	0	32	S1	3,462	-	27.62	-	95,620
2006	82,818	0	32	S1	2,588	-	28.56	-	73,914
2007	90,410	0	32	S1	2,825	-	29.52	-	83,415
2008	68,713	0	32	S1	2,147	-	30.51	-	65,505
2009	54,832	0	32	S1	1,714	-	31.50	-	53,976
	3,222,294	296,457			100,697	9,264	19.91		2,005,342

Average Remaining Life 18.2

Survivor Curve	S1
ASL	32

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
383 -- House Regulators

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	563	0	30	S0	19	-	-	-	-
1941	-	0	30	S0	-	-	-	-	-
1942	-	0	30	S0	-	-	-	-	-
1943	-	0	30	S0	-	-	-	-	-
1944	-	0	30	S0	-	-	-	-	-
1945	-	0	30	S0	-	-	-	-	-
1946	-	0	30	S0	-	-	-	-	-
1947	6,423	0	30	S0	214	-	-	-	-
1948	560	0	30	S0	19	-	-	-	-
1949	508	0	30	S0	17	-	0.50	-	8
1950	1,192	0	30	S0	40	-	0.50	-	20
1951	3,347	0	30	S0	112	-	0.65	-	72
1952	1,274	0	30	S0	42	-	0.97	-	41
1953	1,063	0	30	S0	35	-	1.32	-	47
1954	1,689	0	30	S0	56	-	1.69	-	95
1955	4,186	0	30	S0	140	-	2.05	-	286
1956	8,755	0	30	S0	292	-	2.42	-	707
1957	6,486	0	30	S0	216	-	2.79	-	604
1958	4,537	0	30	S0	151	-	3.17	-	479
1959	4,836	0	30	S0	161	-	3.55	-	572
1960	5,466	0	30	S0	182	-	3.93	-	716
1961	10,139	0	30	S0	338	-	4.31	-	1,457
1962	4,564	0	30	S0	152	-	4.70	-	715
1963	8,161	0	30	S0	272	-	5.08	-	1,383
1964	5,251	0	30	S0	175	-	5.48	-	958
1965	9,372	0	30	S0	312	-	5.87	-	1,833
1966	5,883	0	30	S0	196	-	6.26	-	1,228
1967	8,100	0	30	S0	270	-	6.66	-	1,799
1968	10,199	0	30	S0	340	-	7.06	-	2,402
1969	15,644	0	30	S0	521	-	7.47	-	3,895
1970	15,245	0	30	S0	508	-	7.88	-	4,003
1971	44,148	0	30	S0	1,472	-	8.29	-	12,196
1972	18,706	0	30	S0	624	-	8.70	-	5,426
1973	18,408	0	30	S0	614	-	9.12	-	5,596
1974	29,340	0	30	S0	978	-	9.54	-	9,331
1975	12,375	0	30	S0	413	-	9.97	-	4,111
1976	18,467	0	30	S0	616	-	10.40	-	6,399
1977	29,083	0	30	S0	969	-	10.83	-	10,497
1978	20,730	0	30	S0	691	-	11.27	-	7,785

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
383 -- House Regulators

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	17,688	0	30	S0	590	-	11.71	-	6,903
1980	44,258	0	30	S0	1,475	-	12.16	-	17,932
1981	46,611	0	30	S0	1,554	-	12.61	-	19,588
1982	62,018	0	30	S0	2,067	-	13.06	-	27,008
1983	79,203	0	30	S0	2,640	-	13.53	-	35,714
1984	68,536	0	30	S0	2,285	-	14.00	-	31,975
1985	82,809	0	30	S0	2,760	-	14.47	-	39,945
1986	45,980	0	30	S0	1,533	-	14.95	-	22,918
1987	107,385	3463	30	S0	3,580	115	15.44	-	55,271
1988	84,581	0	30	S0	2,819	-	15.94	-	44,931
1989	114,666	0	30	S0	3,822	-	16.44	-	62,837
1990	112,102	0	30	S0	3,737	-	16.95	-	63,344
1991	63,398	0	30	S0	2,113	-	17.47	-	36,923
1992	95,099	0	30	S0	3,170	-	18.00	-	57,064
1993	152,812	0	30	S0	5,094	-	18.54	-	94,443
1994	115,494	0	30	S0	3,850	-	19.09	-	73,497
1995	126,610	0	30	S0	4,220	-	19.65	-	82,941
1996	114,577	0	30	S0	3,819	-	20.23	-	77,250
1997	85,933	0	30	S0	2,864	-	20.81	-	59,619
1998	340,732	295	30	S0	11,358	10	21.41	15.94	243,379
1999	161,756	0	30	S0	5,392	-	22.03	-	118,790
2000	136,617	0	30	S0	4,554	-	22.66	-	103,214
2001	84,144	0	30	S0	2,805	-	23.32	-	65,399
2002	114,466	0	30	S0	3,816	-	23.99	-	91,531
2003	108,820	0	30	S0	3,627	-	24.68	-	89,535
2004	115,491	0	30	S0	3,850	-	25.40	-	97,792
2005	142,384	0	30	S0	4,746	-	26.15	-	124,109
2006	181,209	0	30	S0	6,040	-	26.93	-	162,656
2007	223,326	0	30	S0	7,444	-	27.74	-	206,530
2008	161,646	0	30	S0	5,388	-	28.60	-	154,115
2009	98,027	0	30	S0	3,268	-	29.52	-	96,443
	3,823,077	3,758			127,436	125	20.00		2,548,257
					Average Remaining Life				20.0

Survivor Curve S0
ASL 30

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
385 -- Industrial Meter Sets

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	40	L0	-	-	15.57	-	-
1941	-	0	40	L0	-	-	15.79	-	-
1942	-	0	40	L0	-	-	16.00	-	-
1943	-	0	40	L0	-	-	16.22	-	-
1944	-	0	40	L0	-	-	16.44	-	-
1945	-	0	40	L0	-	-	16.67	-	-
1946	-	0	40	L0	-	-	16.89	-	-
1947	-	0	40	L0	-	-	17.12	-	-
1948	-	0	40	L0	-	-	17.35	-	-
1949	-	0	40	L0	-	-	17.58	-	-
1950	-	0	40	L0	-	-	17.82	-	-
1951	-	0	40	L0	-	-	18.06	-	-
1952	-	0	40	L0	-	-	18.30	-	-
1953	-	0	40	L0	-	-	18.54	-	-
1954	-	0	40	L0	-	-	18.79	-	-
1955	-	0	40	L0	-	-	19.03	-	-
1956	702	0	40	L0	18	-	19.29	-	338
1957	1,860	0	40	L0	47	-	19.54	-	909
1958	1,172	0	40	L0	29	-	19.80	-	580
1959	366	0	40	L0	9	-	20.06	-	184
1960	1,596	0	40	L0	40	-	20.32	-	811
1961	941	0	40	L0	24	-	20.59	-	484
1962	168	0	40	L0	4	-	20.85	-	88
1963	1,767	0	40	L0	44	-	21.13	-	933
1964	308	0	40	L0	8	-	21.40	-	165
1965	1,098	0	40	L0	27	-	21.68	-	595
1966	1,847	0	40	L0	46	-	21.96	-	1,014
1967	2,885	0	40	L0	72	-	22.25	-	1,605
1968	2,179	0	40	L0	54	-	22.54	-	1,228
1969	1,759	0	40	L0	44	-	22.83	-	1,004
1970	3,485	0	40	L0	87	-	23.13	-	2,015
1971	3,084	0	40	L0	77	-	23.42	-	1,806
1972	2,554	0	40	L0	64	-	23.73	-	1,515
1973	3,174	0	40	L0	79	-	24.03	-	1,907
1974	2,543	0	40	L0	64	-	24.34	-	1,548
1975	1,682	0	40	L0	42	-	24.66	-	1,037
1976	6,518	0	40	L0	163	-	24.98	-	4,070
1977	-	0	40	L0	-	-	25.30	-	-
1978	4,035	0	40	L0	101	-	25.63	-	2,585
1979	3,969	0	40	L0	99	-	25.96	-	2,576

Delta Natural Gas Company
Depreciation Study
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385 -- Industrial Meter Sets

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1980	4,307	0	40	L0	108	-	26.29	-	2,831
1981	33,109	0	40	L0	828	-	26.63	-	22,042
1982	19,688	0	40	L0	492	-	26.97	-	13,276
1983	17,371	0	40	L0	434	-	27.32	-	11,864
1984	26,528	0	40	L0	663	-	27.67	-	18,352
1985	39,740	0	40	L0	994	-	28.03	-	27,846
1986	70,515	0	40	L0	1,763	-	28.39	-	50,047
1987	58,538	0	40	L0	1,463	-	28.75	-	42,081
1988	109,462	0	40	L0	2,737	-	29.13	-	79,703
1989	141,310	0	40	L0	3,533	-	29.50	-	104,217
1990	98,320	0	40	L0	2,458	-	29.88	-	73,446
1991	71,191	0	40	L0	1,780	-	30.27	-	53,866
1992	42,672	0	40	L0	1,067	-	30.66	-	32,705
1993	79,131	0	40	L0	1,978	-	31.06	-	61,438
1994	89,330	0	40	L0	2,233	-	31.46	-	70,265
1995	89,881	0	40	L0	2,247	-	31.88	-	71,634
1996	72,772	0	40	L0	1,819	-	32.31	-	58,774
1997	57,974	0	40	L0	1,449	-	32.74	-	47,457
1998	91,757	0	40	L0	2,294	-	33.19	-	76,144
1999	60,714	0	40	L0	1,518	-	33.66	-	51,087
2000	54,409	0	40	L0	1,360	-	34.14	-	46,432
2001	70,925	0	40	L0	1,773	-	34.63	-	61,405
2002	13,368	0	40	L0	334	-	35.14	-	11,745
2003	54,587	0	40	L0	1,365	-	35.68	-	48,690
2004	53,260	0	40	L0	1,332	-	36.24	-	48,248
2005	31,213	0	40	L0	780	-	36.82	-	28,732
2006	51,486	0	40	L0	1,287	-	37.44	-	48,186
2007	24,432	0	40	L0	611	-	38.09	-	23,265
2008	51,360	0	40	L0	1,284	-	38.79	-	49,811
2009	11,085	0	40	L0	277	-	39.57	-	10,965
	1,740,127	-			43,503	-	31.62		1,375,550

Average Remaining Life 31.6

Survivor Curve	L0
ASL	40

Delta Natural Gas Company
Depreciation Study
As of June 30, 2002
390 -- General Plant Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	35	L0	-	-	11.87	-	-
1941	-	0	35	L0	-	-	12.06	-	-
1942	-	0	35	L0	-	-	12.26	-	-
1943	-	0	35	L0	-	-	12.46	-	-
1944	-	0	35	L0	-	-	12.66	-	-
1945	-	0	35	L0	-	-	12.86	-	-
1946	-	0	35	L0	-	-	13.06	-	-
1947	-	0	35	L0	-	-	13.27	-	-
1948	-	0	35	L0	-	-	13.48	-	-
1949	-	0	35	L0	-	-	13.69	-	-
1950	-	0	35	L0	-	-	13.91	-	-
1951	-	0	35	L0	-	-	14.13	-	-
1952	-	0	35	L0	-	-	14.35	-	-
1953	-	0	35	L0	-	-	14.57	-	-
1954	-	0	35	L0	-	-	14.80	-	-
1955	-	0	35	L0	-	-	15.02	-	-
1956	-	0	35	L0	-	-	15.25	-	-
1957	-	0	35	L0	-	-	15.49	-	-
1958	20,586	0	35	L0	588	-	15.73	-	9,249
1959	27,726	0	35	L0	792	-	15.97	-	12,647
1960	250	0	35	L0	7	-	16.21	-	116
1961	832	0	35	L0	24	-	16.45	-	391
1962	1,197	0	35	L0	34	-	16.70	-	571
1963	23,367	0	35	L0	668	-	16.95	-	11,319
1964	357	0	35	L0	10	-	17.21	-	176
1965	10,712	0	35	L0	306	-	17.47	-	5,346
1966	24,179	0	35	L0	691	-	17.73	-	12,249
1967	149	0	35	L0	4	-	18.00	-	77
1968	3,179	0	35	L0	91	-	18.27	-	1,659
1969	94	0	35	L0	3	-	18.54	-	50
1970	37,380	0	35	L0	1,068	-	18.81	-	20,094
1971	29,546	0	35	L0	844	-	19.09	-	16,119
1972	11,406	0	35	L0	326	-	19.38	-	6,315
1973	84,336	0	35	L0	2,410	-	19.67	-	47,388
1974	480	0	35	L0	14	-	19.96	-	274
1975	700	0	35	L0	20	-	20.25	-	405
1976	2,119	0	35	L0	61	-	20.55	-	1,244
1977	1,374	0	35	L0	39	-	20.86	-	819
1978	568,930	0	35	L0	16,255	-	21.17	-	344,058

Delta Natural Gas Company
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390 -- General Plant Structures and Improvements

1979	23,860	0	35	L0	682	-	21.48	-	14,642
1980	58,518	0	35	L0	1,672	-	21.80	-	36,442
1981	253,709	0	35	L0	7,249	-	22.12	-	160,326
1982	171,370	0	35	L0	4,896	-	22.44	-	109,891
1983	79,384	0	35	L0	2,268	-	22.77	-	51,656
1984	176,763	0	35	L0	5,050	-	23.11	-	116,716
1985	138,267	0	35	L0	3,950	-	23.45	-	92,643
1986	79,344	0	35	L0	2,267	-	23.80	-	53,946
1987	21,786	0	35	L0	622	-	24.15	-	15,031
1988	9,828	0	35	L0	281	-	24.50	-	6,880
1989	158,943	0	35	L0	4,541	-	24.86	-	112,912
1990	247,667	0	35	L0	7,076	-	25.23	-	178,533
1991	910	0	35	L0	26	-	25.60	-	666
1992	26,100	0	35	L0	746	-	25.98	-	19,373
1993	115,754	0	35	L0	3,307	-	26.36	-	87,186
1994	525,596	0	35	L0	15,017	-	26.75	-	401,731
1995	62,193	0	35	L0	1,777	-	27.15	-	48,243
1996	150,022	0	35	L0	4,286	-	27.56	-	118,116
1997	11,853	0	35	L0	339	-	27.97	-	9,474
1998	33,458	0	35	L0	956	-	28.40	-	27,152
1999	310,970	0	35	L0	8,885	-	28.85	-	256,297
2000	21,039	0	35	L0	601	-	29.30	-	17,615
2001	41,155	0	35	L0	1,176	-	29.78	-	35,015
2002	1,331,240	0	35	L0	38,035	-	30.27	-	1,151,371
2003	489,667	0	35	L0	13,990	-	30.78	-	430,691
2004	346,841	0	35	L0	9,910	-	31.32	-	310,391
2005	20,333	0	35	L0	581	-	31.89	-	18,524
2006	55,450	0	35	L0	1,584	-	32.48	-	51,464
2007	49,897	0	35	L0	1,426	-	33.12	-	47,217
2008	8,098	0	35	L0	231	-	33.81	-	7,823
2009	4,250	0	35	L0	121	-	34.57	-	4,198
	5,873,165	-			167,805	-	26.71		4,482,732
				Average Remaining Life					27

Survivor Curve L0
ASL 35