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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE	)	
RATES OF DELTA NATURAL	)	Case No. 2004-00067
GAS COMPANY, INC.	)	

POST HEARING BRIEF OF THE ATTORNEY GENERAL

On April 5, 2004, Delta Natural Gas Company, Inc. ("Delta") filed an application seeking a $4,277,471 increase in rates. The Attorney General ("AG") and Lexington–Fayette Urban-County Government ("LFUCG") were granted intervention. Full discovery, the presentation of intervenor testimony, and a hearing followed. This brief is filed in support of AG's recommendation that Delta be granted an increase of $1,536,110 only, in support of its recommendation concerning the allocation of that increase, and in support of his recommendations concerning Delta's rate base and pro forma test period operating income.

1. RATE BASE

Delta's proposed test year rate base as measured at the end of December 31, 2003, should be adjusted to remove $39,440 of PSC assessments in accord with Commission policy.[1] It should also be adjusted to reflect the appropriate cash working capital amount which changes with the

[1] See, In the Matter of: *The Application of Union Light, Heat and Power Company for an Adjustment of Rates*, PSC Case No. 92-346 Order dated July, 1993, p. 5; *The Application of Kentucky Utilities Company for an Alternative Method of Regulation of its Rates and Service*, PSC Case No. 98-474 Order dated January 7, 2000, p. 50; *The Adjustment of the Gas Rates of the Union Light, Heat and Power Company*, PSC Case No. 2001-00092, Order of January 31, 2002, p.7; *The Application of Louisville Gas and Electric Company to Adjust its Gas Rates and to Increase its Charges for Disconnecting Service, Reconnecting Service and for Returned Checks*, PSC Case No. 2000-00080, Order of September 27, 2000, p. 16.

flow-through of test year expenses.[2] Finally, the depreciation reserve adjustment that represents the annualized impact on rate base of the difference between Delta's proposed pro forma annualized deprecation expenses and the test year per books depreciation expense should be adjusted to reflect the AG's recommended depreciation expense. This adjustment increases rate base by $759,744.[3]

2. OPERATING INCOME

The AG has recommended a series of adjustments to the pro forma operating income proposed by Delta which increase the proposed test year operating income by $870,870. That recommendation includes the following adjustments.

2.1 Test Year-End Customer Growth

In this case, Delta has proposed that there be no customer growth adjustment because the test year ends December 31 and simple subtraction shows there to be fewer customers at the end of the test year than at the end of the preceding December 31. The proposed approach is unlike that proposed by Delta witness Walker who sponsored the Company's proposed customer growth adjustment in the last Delta case, a case in which the test year also ended December 31st.[4] The proposed approach is even unlike the approach proposed Mr. Seelye for LG&E in a case pending when this action was filed.[5] The proposal is unwarranted and fails to address the issue a customer growth adjustment is designed to address.

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2 The amount is set out in Schedule RJH-4.
3 See, Schedules RJH 3 and 14.
4 See, *In the Matter of: An Adjustment of Rates of Delta Natural Gas Company, Inc.*, Case No. 99-176
5 *In the Matter of: An Adjustment of the Gas and Electric Rates and Conditions of Louisville Gas and Electric Company*, PSC Case No. 2003-00433

The AG has proposed alternative customer growth adjustment calculations utilizing two methodologies accepted by the PSC for Delta in its last two rate cases. The first methodology, comparing the test year-end to the test year average customer growth, was accepted for use by the Commission in Delta's last rate case, PSC Case No. 99-176. It produces an increase in revenues of $239,331, and increase in the offsetting expense adjustment of $29,677 for a net revenue adjustment of $209,654.[6] The second methodology, proposed by the AG and accepted for use by the Commission in Delta's next-to-the-last rate case, Case No. 97-066, calculates test-year end customer growth by applying a half-year compound average growth rate to the test year's average number of customers. This methodology results in an increase in revenues of $98,189, an increase in the offsetting expense of $12,175 and a net increase in revenues of $86,014.[7]

2.2 Interest on Customer Deposits

In accord with the policy iterated by the PSC in Case No. 99-176, the AG recommends that the interest on customer deposits in the amount of $33,554 be excluded from operating income. While the Company, in its direct case, had included this interest expense for ratemaking purposes in this case, in its rebuttal case Delta removed these expenses.[8]

2.3 401(k) expense

The AG has recommended that Delta's actual test years 401(k) expenses reflected by the Company in its direct case should be increased by $23,833 to normalized the test year expense level. During the hearings, Delta agreed with this AG recommendation.

[6] See, schedule RJH-6A.
[7] See, schedule RJH-6B
[8] See, schedule RJH-7.

2.4 Amortization of Rate Case Expense

The average period between the three most recent Delta rate cases is about 4.25 years and the actual period between the last case and this case is nearly five years. Accordingly, Delta's recommended normalization period of 3 years is too short. The rate case amortization period should be 4 years. Given that there has been no controversy in this case concerning the reasonableness of the expense to be amortized, the rate case expense to be amortized is the actual rate case expense.

2.5 Director's Fees and Expenses

Delta's directors fees and expenses have been raised dramatically in each of the five years since its last rate case, with retainers alone standing in the test year at a generous $149,500, an amount nearly double the total of the fees at the time of its last rate case. In addition, the test year includes stock of $20,538 and bonuses of $51,440. The AG recommends that the bonuses of $51,440 be excluded from test year expenses as the nonrecurring expense Delta acknowledges them to be, just as Delta is excluding the $403,865 of bonuses paid out to management in test year.

It is not appropriate to charge bonuses to ratepayers. It is not appropriate to base rates on non-recurring expenses. As non-recurring bonuses, it is doubly inappropriate to include these as a base rate expense. Therefore, the expense should be disallowed.

Nevertheless, Delta maintains that it should be allowed to consider these as an expense because the amount is representative of the level of director fees and expense it expects to incur while the rates are in effect. In essence then, Delta asks the Commission to treat the bonus as if it were a pro forma known and measurable director fees expense. Certainly the regulations permit an historic test year to be updated with pro formed expenses representing known and measurable changes, but when that is done there are certain requirements that must be met in connection with the consideration of the expense. 807 KAR 5:001 Section 10 (7) provides:

> (7) Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:
>
> (a) A detailed income statement and balance sheet reflecting the impact of all proposed adjustments;
>
> (b) The most recent capital construction budget containing at least the period of time as proposed for any pro forma adjustment for plant additions;
>
> (c) For each proposed pro forma adjustment reflecting plant additions provide the following information:
>
> ...
>
> (d) The operating budget for each month of the period encompassing the pro forma adjustments;
>
> (e) The number of customers to be added to the test period - end level of customers and the related revenue requirements impact for all pro forma adjustments with complete details and supporting work papers.

Delta's effort to increase base rates with using a non-recurring bonus as a substitute for a bona fide known and measurable expense must fail. It is clear from the requirements of the regulation that in order to adapt the historic test year to accommodate a know and measurable pro formed expense, the expense must be certain in nature and there must be a full consideration of those changes other than the change in the expense that will be in place when the pro forma expense is considered. Unlike the situation here, when a pro forma expense is presented accompanied by the information required by the regulation, the Commission can consider the impact of the expense on the financial needs of the company rather considering only the simple existence and amount of the expense. When a known and measurable expense is submitted, it is an actual expense, not a substitute that cannot qualify in its own right for recovery. The Directors bonus of $51,440 should be excluded.

By way of response to the PSC's Third Data Requests, Item 13, Delta indicated that in March 2004, it had raised its director retainer fees to $205,200 from the $149,500 it had implemented just nine month earlier, in June 2003. This response, while establishing the amount of the expense and the timing of the implementation of the expense, in no way seeks to justify the near 30% increase in fees only nine months after the last hike in fees. Pursuant to KRS 278.190 (3), Delta bears the burden of proving its entitlement to a rate increase. Simply stating the amount of an out of test year expense does not satisfy that burden, particularly as the other information required by regulation to consider it as a pro forma expense under 807 KAR 5:001 Section 10 (7) is not provided. The tone of the cross examination during the hearing[9] suggests that Delta believes it is entitled to this amount absent a challenge from the AG as to the reasonableness of the fees. That is not the case – the burden is on the utility and does not shift. KRS 278.190 (3). The $51,440 of claimed non-recurring bonuses for directors and any other out of test year, post-application increase of director fees should be disallowed.

In addition, the $686 of Christmas dinner and Christmas gifts provided to the directors should be excluded.[10]

2.6 Outside Services – Accounting Expense

A review of the history of accounting expenses for Delta shows that the test year expense runs 3.5 times higher than the accounting expense experienced in the preceding five years, and

[9] Transcript of Evidence ("TE") pp. 214-218.
[10] DT Henkes, p. 23.

that the accounting expenses were much more alike from year to year. The culprit, so to speak, is $240,727 of new Sarbanes/Oxley related accounting expenses. Of those Sarbanes/Oxley expenses, $180,420 is expected to be recurring and $163,328 is non-recurring.[11] However, beginning March 2005, some 15 months after the close of the test year, Delta estimates that it will begin to incur a recurring internal audit expense associated with Sarbanes/Oxley compliance that will run in .the neighborhood of $80,000 and therefore suggests that its accounting expenses should be pro formed to approximately $260,000. An estimate is not a known and measurable expense. Even if it were, Delta has not provided the other information required by 807 KAR 5:001 Section 10 (7) to allow the Commission to consider the impact of the expense upon Delta's financial condition and requirements, not just its estimated amount. Delta has failed to meet the burden of proof placed on it under KRS 278.190 (3).

Further, the expense is not to be incurred until some time in 2005. While there is no explicit limit on how far forward one can reach from the test year for a pro forma expense, the regulations requirements for accompanying information set out in (7)(a)(d) and (e) do not seem to lend themselves to the kind of reach forward proposed here. Certainly that information has not been provided by Delta. Therefore, the expense should be denied.

2.7 Outside Services-Computer Expense

Sarbanes/Oxley compliance also created a non-recurring test year expense of $42,404 for Delta arising from scanning services provided by Source Imaging.[12] Again, while Delta acknowledges that this expense is non-recurring and while it did not present a request for a pro forma computer expense together with the surrounding information required by 807 KAR 5:010

[11] DT Henkes, pp. 24-25.
[12] DT Henkes p. 26.

Section 10 (7) in its application, it nevertheless maintains that as this expense is representative of the overall level of expense it expects to experience base rates should be set on this representative expense. Delta bears the burden of proof and is required to comply with Section 10 of 807 KAR 5:001. It has not met those requirements. The non-recurring expense should be excluded.

2.8 Miscellaneous Expense Adjustments

The AG recommends the removal of expenses from nine sources, totaling $87,343, having to do with lobbying, entertainment and awards, spousal expense, and other promotional endeavors. Of this, Delta has conceded that $44,200 of Incentive expenses in Acct. 930.110 should have been removed.[13]

Under 807 KAR 5:016, the utility has the burden of proving that advertising, direct or indirect, provides a material benefit. The regulation expressly excludes promotional, political and institutional advertising. Mr. Henkes identified various items having to do with promotional, political, and institutional advertising that should be excluded in his Direct Testimony and further explained the sources for his information on cross-examination.[14] They include lobbying expenses ($758), AGA dues associated with public affairs and institutional advertising ($7,389), Promotional and Economic development expenses included in Acct. 930.090 ($4,914), lobbying and economic development expenses from Acct. 921.220 ($5,161) and lobbying and community relations expense in Acct. 921.29 ($2,022). He excluded employee gifts and awards banquets and social events and parties in the amount of $19,886 in accord with longstanding Commission

[13] See, Delta's response to AG 1-43 and DT Henkes, p. 27.
[14] DT Henkes, pp. 26-29; TE, pp. 225-229.

policy that they produce no material benefit.[15] He excluded employee membership expenses contained in Acct. 921.070 ($2,749) for the same reason. The Commission should likewise exclude these expenses for Delta.[16]

2.9 Depreciation Expense

Delta confirms that its pro forma depreciation expense should have included a $12,000 net expense credit for the Tranex and Mt. Olivet Acquisition Adjustment amortizations. There is no controversy over the inclusion of this credit in calculating the depreciation expense.

The AG further recommends reducing the proposed pro forma depreciation expense by $747,744 to reflect a matching of the recovery of depreciation expense to longer, more appropriate service lives for distribution mains (account 376), measuring and regulating station equipment (account 369), and meter and reg. installation (account 382) than were proposed by Delta and to reflect a smaller and more appropriate net salvage expense than that estimated by Delta.

Mr. Seelye continued to use the depreciation rate the Commission adopted for distribution mains – Account 376 - in 1985.[17] He provided no SPR analysis because he did not rely on the results of his SRP analysis.[18] His stated reasons for not relying on a SPR analysis are that either the data is not available, apparently not applicable here as he indicates the inputs were available,[19] or that the resulting statistics were not satisfactory. Regardless, he chose to continue the use of the 1985 rate of 2.5%. In 1985, no one provided a depreciation study in the case.

[15] See footnote 8, DT Henkes, pp. 27-28.
[16] The expenses and their sources are detailed in schedule RJH 13.
[17] In 1985 the Commission found the 33 year useful life Delta used to be too short and established a 40 year life for distribution mains. See, *In the Matter of: An Adjustment of Rates of Delta Natural Gas*, Case No. 9331, Order of November 15, 1985, pp. 11-13.
[18] TE, p. 198, lines 13-14.
[19] TE, p. 198, line 15.

Nevertheless, the Commission decided that the depreciation rates historically utilized involved service lives that were too short. Therefore, the Commission adopted a 40 year service life as the appropriate service life for Account 376, which lowered the depreciation rate previously used by Delta.

Here, the AG's depreciation expert did an analysis of Acct. 376 – distribution mains using both the Geometric Mean Turnover ("GMT") methodology and the Simulated Plant Record Balances ("SPR") methodology. The GMT indicates the use of a 52 year average group life for distribution mains. The SPR analysis indicates that the most appropriate average group life would be a 77 R0.5 year life and curve. But, because distribution services are included in the data, Mr. Majoros recommended use of the 52 SO year life, a result that is corroborated by the GMT, even though it was rank 7 for the SPR analysis.

Though Mr. Seelye complained that he was unable to verify the results of the SPR analysis done by Mr Majoros, verification is possible.[20] Moreover, Mr. Seelye and Delta raised no concern about the utilization, application, and verification of the GMT methodology that produced the corroboration for the 52 year life proposed for use by the AG. Mr. Seelye complained that Mr. Majoros did not account for the impact of the transfer of services, but that is the reason Mr. Majoros recommended the 52 year life corroborated by the GMT even though it was ranked 7 best fit by the SPR and is substantially shorter than the best fit 77 year service life. Mr. Majoros also took account of that transfer in adding Account 380 Services Reserve to

[20] Because the outputs of the his model were provided Mr. Majoros, the results of his SPR analysis can be replicated and verified by utilizing the procedure laid out by Mr. Majoros at the hearing (TE, p. 288 and 289) without possession of his model. This is done by comparing the simulated balances to the actual balances, both provided on diskette, squaring the differences and then summing the squared differences. Provision of the model itself may be necessary to verify the Mr. Seelye's SPR analysis as he only provided inputs (TE, p. 198, line 18) not outputs, but it is not necessary to verify Majoros's analysis.

Account 376 Distribution Mains because that is where the Account 380 investment is in Exhibit MJM-2.[21] The Commission should use a life of 52 years for Account 376.

The perfect depreciation rate is the one that accurately estimates service life so that the recovery of costs matches the life over which the expenses are recovered and results in a rate that it neither too high nor too low The use of lives that are too short not only causes depreciation expense to be higher each year than is necessary, it sets up the potential for excess recovery by the utility on a regular basis – a fact that was recognized by the Commission in 1985 absent any depreciation study by either the company or the AG when it chose to lower Delta's depreciation rate because the life being used was too short.

The AG has provided a depreciation study demonstrating the appropriateness of a 52 year service life for distribution mains. That service life should be adopted by the Commission. Further, the Commission should use the 45 R2.5 life and curve recommended by Mr. Majoros for Account 369-Measuring and Regulating Station Equipment[22] and the 44 R2.5 life and curve recommended for Account 382-Meter and Reg. Installation.[23]

Delta also seeks to build excess negative net salvage into its depreciation rates. With no studies to support it, Mr. Seelye has incorporated approximately $45,000 of negative net salvage expense into Delta's accruals. Delta's actual experience over the last five years has been only $11,274. Delta bears the burden of proof for each element of its depreciation claim. It cannot simply pull a number out of thin air to meet this burden. The net salvage included in the annual accrual should be no higher than $11,274 recommended by Mr. Majoros, the only net salvage estimation presented in this case that has a basis in fact.

[21] See, Exhibit MJM-2, p. 2, fn. 6.

[22] DT Majoros, p. 20.
[23] DT Majoros, p. 21.

3. RETURN ON EQUITY

The AG recommends a return on equity of 10.3% for Delta and a return to overall capital of 7.732%.[24] In determining the cost of equity, Mr. King performed a Discounted Cash Flow ("DCF") analysis using a comparable company/peer group method, a DCF Book Value Growth Method, the Capital Asset Pricing Model and a DCF Delta Value Line Forecast. Delta has proposed a 12.5% return on equity.

One of the major points of disagreement concerns whether it is appropriate to put in a size adder for Delta as a small company. Dr. Blake maintains that a size adder is necessary because smaller companies are more risky and have been shown over time to earn higher rates of return than large companies. He cites an article by Michael Annin, published in the Business Valuation Review to that effect in support of his contention.[25] Mr. King had already pointed out that the studies giving rise to the assumption of the necessity of a size adder are made using data from companies primarily in the general marketplace, not public utilities operating in franchised service areas with established rates, even earning streams resulting from weather normalization adjustments, and the right to seek higher rates as needed. Not only does the Annin article fail to indicate that it is speaking of anything but the predominantly competitive marketplace, it certainly does not address the impact on its suppositions of a shift of risk from the company to the ratepayers affected by the implementation of a weather normalization clause.

When the weather normalization clause ("WNA") was implemented, the Commission specifically acknowledged that the adoption of a weather normalization clause would generally warrant a lower return for a company, but that given Delta's financial condition at the time, it

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[24] TE, p. 269. The AG has accepted Delta's proposed capital structure and cost of debt. DT King, p. 21.

[25] Blake Rebuttal, pp. 1-3. On cross examination, Dr. Blake admitted that he has no idea about Annin's credentials, only that he saw the article. TE, p. 139.

was not going to utilize a lower rate of return.[26] Delta has not suffered the swings of earnings indicative of higher risk since the 1999 implementation of the weather normalization clause. Indeed, its earnings per share have stayed within a narrow band of $1.42 to $1.49.[27] Partly for this reason, Delta is recommended by investment analysts as a low earning risk investment.[28] It would be absurd to stabilize Delta's earnings through the WNA and then to continue to treat Delta as if that stability had not been accomplished. The ratepayers should begin to see some benefit associated with bearing the risk of weather variation that once rested on the Company.

Dr. Blake maintains that the small company adder is necessary because Delta has not earned its allowed rate of return in any of the last nine years.[29] This contention is irrelevant. Not only does profitability have little to do with size, risk assessments are a function of uncertainty, not profitability. So stable and risk free were regulated utilities in those years where they had no function but service of their franchised territories under regulated rates that utility stocks were generally considered "Widows and Orphan" stocks whose returns, though low in comparison to the general marketplace, were nevertheless certain and therefore low risk.

Finally, it should be noted that despite his misgivings about the correlation of size and risk for a company that is garnering favorable analysts' reviews by reason of its stable earnings, Mr. King actually did make a size adjustment. He recommended that the Commission look at both size-adjusted and non-size-adjusted comparable industry returns as out limits on the DCF return that could reasonably be applied to Delta.[30]

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[26] In the Matter of an Adjustment of the Rates of Delta Natural Gas Company, Inc., Case No. 99-176, Order of December 27, 1999, p. 33.
[27] DT King, p. at 12.
[28] DT King, p. 12.
[29] Blake Rebuttal, pp. 1-2.
[30] DT King, p. 13; TE, p. 27.

A second major point of disagreement concerns Mr. King's comparable gas companies. Dr. Blake argues that five of these companies are diversified and should be excluded. When these companies are excluded, the average rate of return increases from 9.4 percent to 10.2. The propriety of this exclusion, however, is not as clear-cut as Dr. Blake suggests because the DCF returns to these companies are by no means uniform. They range from 5.9% and 5.8% for Energen and NICOR to 14.1% and 11.5% for Southwest and UGI.[31] Although on average excluding these companies raises the composite DCF, it is not clear that this is more than the chance effect of removing five very different companies.

Another area of contention is Delta's leverage adjustment. Dr. Blake contends that Delta has one of the lowest equity ratios in the panel of natural gas distribution companies when correct comparisons are made.[32] The simple point is that though Delta may have had a leveraged capital structure in December of 2003, within three months of the close of the test year and before the filing of this application, Delta eliminated the problem by selling 600,000 shares of new equity, a fact that is only reflected in 2004 data. Moreover, given the relative size of the peer group companies and that of Delta, it is unlikely that any of those companies would have issued so much stock as to affect the kind of increase in the equity ratio present for Delta with its stock issue.[33]

Dr. Blake takes issue with Mr. King's size premium to relate the market CAPM results to beta. The size premium is purportedly recognition of risk, and Delta's risk is already reflected in its beta.[34] While Dr. Blake contends that an arithmetic mean should be used because it is

[31] . See, Exhbit CWK-1.
[32] Blake Rebuttal, p. 13-14.
[33] TE, pp. 273. 275-276.
[34] DT King, p. 16.

recommended by Ibbotson,[35] Mr. King pointed out that the geometric mean was more appropriate for use because it reduces the effect of outliers.[36] Finally, Dr. Blake uses the size premium between micro-cap companies and large cap companies. By definition, in CAPM the premium is between the micro-cap companies and the overall market.[37]

Dr. Blake maintains that the 20-Year U. S. Treasury Bond as the more appropriate means to measure the risk free rate for use in the CAPM calculation.[38] Mr. King maintains that the 20-Year bonds, though free from the risk of default, are not free from the risk of inflation that will erode their value at maturity and proposes instead, the use of a one year bond as better indicator of the risk free rate. This is so because, unlike the 20-year bond, it is free of the risk of default. Further, it has no inflation risk and it matches the general turnover horizon for stock portfolios.[39] Dr. Blake's criticism is without merit.

Dr. Blake criticizes Mr. King for using an average increase of shares of 3-4% for the last five years to represent the increase in book value per share resulting from the issuance of new shares the Book Value Growth Model. He maintains that Mr. King should have used a 7.34% increase in shares.[40] Mr. King maintains that, as a matter of judgment, the 3-4% represents a compromise between the impact of the large 600,000 share stock sale and the low gains from stock sales for the preceding four years and is therefore more appropriate for use in the DCF Book Value Growth Model than is the 7.34% .[41]

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[35] Blake Rebuttal, pp. 4-5. Dr. Blake did not understand why Ibbotson recommends use of the arithmetic means, and simply relies on the fact that it does so. TE. Pp. 146-148.
[36] TE, p. 277.
[37] DT King, p. 17, lines 9-10.
[38] Blake Rebuttal, p. 15.
[39] DT King, pp. 17-18.
[40] Blake Rebuttal, p. 17.
[41] TE, pp. 281-282.

Dr. Blake continues his theme of the necessity of a size premium in his criticism of Mr. King's weighting of the results of the various models to derive Delta's return on equity, saying that had Mr. King properly adjusted his results or size the weighting would have been unnecessary.[42] Given that Dr. Blake has not shown the relevance of the size premium for a public utility serving a franchised territory with a weather normalization clause that stabilizes earnings and with the right and ability to seek an increase in rates when its earnings are to low, as opposed to small companies competing in a large company world with no financial safety nets, Dr. Blake's criticism is unwarranted.

While Dr. Blake repeatedly asserts that Mr. King's methodologies are wrong and that Mr. King's results are artificially low, the reverse is true. Dr. Blake's own results are high and his efforts are clearly designed to make Mr. King's results even higher than are his own results. The Commission should establish a return on equity of 10.3% for an overall return of 7.732%.

[42] Blake Rebuttal, p. 18.

4. COST OF SERVICE

Because Delta's data does not fit the general underlying assumption of both the zero intercept method and the minimum size analysis - that costs decrease as pipe size decreases - proper application of the zero intercept analysis using all of Delta's data produces highly irregular results.[1] For Delta, pipe of the same size has radically different cost and pipes of lesser size often have higher costs than pipes of larger sizes. Consequently, when all of the Delta data is utilized in the zero intercept analysis the results are highly irregular.

The results are irregular in that over half of the mains costs are classified as customer related, as opposed to approximately 20% of the mains costs being classified as customer related in the zero intercept analysis of other utilities and in the example shown in he NARUC Gas Distribution Rate Design Manual. They are irregular in that the size of a zero inch main is substantially greater than are the costs of 2/3ds of Delta's pipe sizes smaller than 4 inches; in that fifty percent of the pipe sizes are less than half of the calculated zero inch size; and in that of all of the pipe sizes, over a third of all pipe sizes, have costs below the calculated zero inch size.[2]

As shown by comparison to the results obtained by LG&E in Case No. 2000-080, (where a weighted least squares analysis is applied to data that more closely fits the underlying proposition that pipes of smaller sizes have costs less than those of larger sizes) Delta's unusual underlying data (which completely belies that proposition) produces abnormal as well as unusual results. The situation is made all the worse as over 80 % of Delta's investment is in 2 and 4 inch pipe.[3]

For this reason, the AG proposes an alternative zero intercept analysis which performs the standard analysis, but uses data pertaining only to Delta's 2 and 4 inch pipe sizes, those sizes in which 80% of Delta's investment resides. This analysis produces results consistent with the

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[1] DT Brown Kinloch, p. 8.
[2] DT Brown Kinloch, p. 5.
[3] DT Brown Kinloch p. 5-8.

usual results of a zero intercept analysis in which the underlying data fits the underlying assumption that pipe of lesser size has lesser costs than pipe of greater size. All of the pipe costs are greater than the calculated zero inch pipe cost and the portion of mains assigned to the customer component falls into the more typical range of 20.10 percent.

When the resulting change in the distribution main cost allocation is carried into the Functional Assignment and Classification of Costs and the resulting changes there are then carried forward into the Allocation of Costs to Customer Classes, the return provided by each of the customer classes changes as shown on the table presented at the top of page 10 of Brown Kinloch's direct testimony. Based on those class returns, the AG recommends that the portion of any increase be allocated as follows: Residential - 62.15%; Small Non-Residential - 11.63%; Large Non-Residential - 21.55% and Special Contracts - 4.66%. Both the Company and the AG are agreed that the interruptible and Off System Transportation classes should bear none of the increase.[4]

The most controversial aspect of this recommendation, from Delta's point of view is that, utilizing the AG's proposed increase, the special contract class would be assessed $63,636 of the proposed increase. If the increase granted is greater than that proposed by the AG, the special contract share would increase proportionately.[5] Delta has proposed no increase for the special contract customers, even though this class has returns that are less than average under the Company's cost of service study as well as under the AG's cost of service study. It argues that Delta is so at risk of losing its special contract customers to competing sources, it cannot risk requiring these customers to pay their share of a rate increase. As Mr. Brown Kinloch points out, the customers that Delta is loosing are the residential customers, not the special contract customers.

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[4] DT Brown Kinloch p. 11.

[5] DT Brown Kinloch, p. 13.

5. MONTHLY CUSTOMER CHARGE

In recognition of the Commission's directive in Case No. 2000-080,[6] care was taken by Mr. Brown Kinloch to assure that costs were not shifted among the classes in developing the AG recommended monthly customer charge of $9.00 for residential customers. At the same, in accord with the NARUC Gas Distribution Rate Design Manual, the AG has recognized that though certain costs are labeled customer costs for the purposes of developing the allocation of costs among classes, they should be collected from the class to which they are allocated on a commodity basis as they vary with the volume of gas sold rather than with the number of customers served and thus are not appropriately included in the monthly customer charge.[7]

The AG also recommends that the monthly customer charge for the Small Non-Residential class be reduced to $14.60 and that the Large Non-Residential Charge be increased only to $70.00.[8]

6. RECONNECT CHARGE

The AG recommends that the Commission deny Delta's proposal to increase the reconnect charge from $40 to $48.[9] The reconnect charge represents a direct hardship for those whose disconnection was the result of financial harship in the first place, and any increase in that fee only increases the level of hardship.

7. GTIR&D TARIFF

The AG is opposed both to the collection of any fee for the Gas Technology Institute for Research and Development. Given the striking absence of material benefit provided to the residential customer by GTI, it would be bad policy to require that the residential customer

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[6] In the Matter of: The Application of Louisville Gas & Electric Company to Adjust its Gas Rates and to Increase its Charges for Disconnecting Service, Reconnecting Service and Returned Checks, Case No. 2000-080.

[7] DT Brown Kinloch 14-15; TE, p. 296.

[8] DT Brown Kinloch, p. 14-15.

[9] DT Brown Kinloch, pp. 16-17.

contribute at all towards the GTI. Because most of Delta's customers are residential, it makes little sense to support the GTI at all. Furthermore, the tariff, as proposed, collects nothing from transportation customers though they are seemingly the beneficiaries of more of the services of GTI than are residential customers. Therefore, no tariff should be implemented to collect a contribution for GTI. If some expense is collected, it should be collected through base rates so that all potential beneficiaries contribute.[10]

CONCLUSION

In conclusion, the AG recommends that Delta's rates be increased no more than $1,536,110, that it be awarded a return on equity of 10.3%, that the costs be allocated in accord with Section 5 of this brief, that the Monthly Customer Charges and the Reconnect Charge be established in accord with Section 6 and 7 of this brief, that no costs be recovered in connection with the Gas Technology Institute and that the GTIR&D tariff be denied.

Respectfully Submitted,

Elizabeth E. Blackford
Dennis G. Howard II
Assistant Attorneys General
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601-8204
(502) 696-5453

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[10] DT Brown Kinloch, pp. 17-19.

Notice of Filing and Certificate of Service

I hereby give notice that I have filed the Original and ten true copies of the foregoing Post Hearing Brief of the Attorney General with the Executive Director of the Kentucky Public Service Commission this the 10th day of September, 2004, and further certify that this same day I have served the parties by mailing a true copy of same to:

JOHN F HALL
VICE PRESIDENT FINANCE
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391

ROBERT M WATT III ESQ
STOLL KEENON & PARK LLP
300 WEST VINE STREET
SUITE 2100
LEXINGTON KY 40507-1801

LESLYE M BOWMAN
DIRECTOR OF LITIGATION
LFUCG DEPARTMENT OF LAW
200 EAST MAIN STREET
LEXINGTON KY 40507

MARIAN CARPENTER
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391

CONNIE KING
DIRECTOR RATES & TREASURY
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391