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BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO: 2003-00433

POST HEARING BRIEF OF THE ATTORNEY GENERAL

On December 29, 2003, Louisville Gas and Electric Company ("LG&E"), filed a rate case seeking a rate increase of $63.764 million for its electric operations and $19.106 million for its gas operations. On December 29, 2003, Kentucky Utilities Company ("KU"), LG&E's sister company, filed its application for a rate increase of $58.3 million.

The Attorney General ("AG"), Kentucky Industrial Utility Customers, Inc. ("KIUC"), the Environmental and Public Protection Cabinet, Division of Energy ("KDOE"), the United States Department of Defense ("DOD"); the Kroger Company ("Kroger"), the Kentucky Association for Community Action, Inc. ("KACA"), the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"), Metro Human Needs Alliance ("MHNA"), People Organized and Working for Energy Reform ("POWER"), Lexington-Fayette Urban County Government ("LFUGC") intervened in the proceeding. Subsequently, North American Stainless, L.P. ("NAS") was joined as a party by the consolidation of actions then pending[1] with reference to the rates and tariffs for its service.

On March 31, 2004, the cases considering the continuation of the Earnings Sharing Mechanism for KU and LG&E[2] were consolidated with the rate cases.

[1] Cases No. 2003-00396 and 2003-00376.

[2] Cases No. 2003-00335 and 2003-00334.

Following discovery and extensive negotiations, all parties entered into a partial settlement and stipulation concerning all issues presented by the two rate cases, the two cases concerning the earnings sharing mechanism, and the two cases concerning service to NAS other than the revenue requirements of KU and of the electric operations of LG&E. All parties except the AG entered into a Stipulation and Recommendation that the revenue requirement of KU would be $46,100,000 and the revenue requirement for LG&E for its electric operations would be $43,400,000. This brief addresses all matters pertaining to the revenue requirements of LG&E for its electric operations.

CAPITALIZATION

The Attorney General agrees with all of the pro forma adjustments to capitalization proposed by LG&E except the adjustment for Minimum Pension Liability ("MPL"), an adjustment made solely to common equity. LG&E proposes to reverse actual write-downs to its common equity balance previously recorded in accordance with SFAS 130 to reflect LG&E's MPL. This proposed adjustment increases the proposed adjusted electric capital structure by $25,443 million and requires the corresponding establishment of a regulatory asset for the amount of the MPL write down.[3]

There are several reasons to refuse to allow the reversal of the MPL write-down. First, refusing to allow the reversal of the MPL write-down to common equity would be consistent with previous PSC action. The MPL write-down was actually made on the Company's books during the test year and will continue to affect its capitalization in the future. Under like circumstances, the Commission has refused to allow the reversal of a write-down.[4] Second, there is a question as to whether the establishment of the corresponding regulatory asset comports with

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[3] Direct Testimony of Robert Henkes (hereinafter Henkes Direct), pp. 9-10.

[4] See, *In the Matter of: Application of Louisville Gas & Electric Company for Approval of an Alternative Method of Regulation of Its Rates and Service,* Case No. 98-426, Order of 7 January 2000, pp. 64-65.

SFAS 71 because the MPL regulatory asset would only be extinguished through balance sheet accounting while SFAS 71 is oriented to the recovery of deferred expenses through rates and, therefore whether it is permissible at all. Third, establishing the regulatory asset may give rise to recovery of any remainder of the asset as may exist at the time of the next rate case without a prudence review of the costs.[5] Given this, the MPL write-down reversal should not be allowed.

Disallowance of the MPL write-down reversal results in an adjusted electric capitalization as of September 30, 2003, of $1,460.257 million.[6]

RATE BASE

While LG&E presented an unadjusted electric original cost rate base, it did not present an adjusted electric original cost rate base for the purpose of determining the appropriate return on rate base as compared to the appropriate return on capitalization. An adjusted electric original cost rate base has been prepared and presented by the AG on Schedule 3 of the Direct Testimony of Robert J. Henkes ("Henkes Direct, Schedule _").

The adjusted electric original cost rate base includes the removal of the net environmental surcharge rate base amount of $200.962 million associated with the post-1995 ECR Plan environmental rate base investment. That amount is comprised of $203.504 million for environmental plant in service and CWIP offset by approximately $2.570 million for associated accumulated depreciation and deferred income taxes and $28,000 for cash working capital.

The adjusted electric original cost rate base includes removal of approximately $3.3 million capitalized E.W. Brown rate base investment and removal of approximately $.6 million of ARO assets.[7]

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[5] Henkes Direct, pp. 11-12. Mr. Majoros, the accounting witness in the companion KU case, Case No. 2003-00434, has cited an example where a utility is seeing such an adjustment in Michigan P.S.C. Case No. 13808, *Application of Detroit Edison Company*.
[6] See, Schedule RJH-1, line 1 and Schedule RJH-2 filed with the Direct Testimony of Mr. Henkes.
[7] Henkes Direct, p. 16.

An adjustment increasing rate base by $13.375 million is made to reflect the annualized impact on depreciation reserve of the AG's recommended depreciation expense adjustment.[8]

An adjustment has been made to remove the $333,000 associated with the Carbide Lime inventory that was written off the Company's books in November 2002 from the Materials and Supplies component of the electric original cost rate base.[9]

An adjustment has been made to reduce the cash working capital requirement by $28,000 associated with removal of all expenses relating to the post-1995 ECR Plan and $410,000 relating to the Demand Side Management Plan, as both are fully recovered in separate mechanisms.[10]

The recommended cash working capital will also have to be further adjusted by the Commission to reflect all pro forma test year electric operation and maintenance expenses ordered by the Commission. That amount in not now known.

REVENUE REQUIREMENT

A. Kentucky State Income Tax Rate.

In 2002, the Commission adopted the use of an effective state income tax rate for the Union Light, Heat and Power Company[11] on a trial basis. The effective state income tax rate is a result of the filing of consolidated Kentucky corporation income tax returns. Though the Commission expressed concern over the utilization of an effective tax rate when that rate experiences significant year to year fluctuation in the Union case,[12] the effective rate for LG&E has been nearly constant, ranging between 7.41% and 7.87% over the past four years. Therefore,

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[8] Henkes Direct and Schedules 3 and 8.
[9] Henkes Direct 16-17 and Schedule 3
[10] Henkes Direct pp. 18-19 and Schedule 3.
[11] In the *Matter of Adjustment of Gas Rates of the Union Light, Heat and Power Company*, Case No. 2001-00092.
[12] See, Order of 31 January 2002, pp. 58-60 entered in Case No. 2001-00092, *Matter of Adjustment of Gas Rates of the Union Light, Heat and Power Company*.

it is probable that utilization of a 7.87% effective tax rate will be reflective of the effective state income tax rate to be paid by LG&E during the effective dates of these rates. Accordingly, the trial use of an effective state income tax rate should be extended to LG&E in order that its ratepayers, like those of Union, receive the benefit of the reduction to the 8.25% Kentucky income tax resulting from the filing of consolidated returns.[13]

In order to permit the ratepayers to enjoy the benefit of the lower effective state income tax, it is necessary that the effective state income tax rate be applied both in the determination of the pro forma test year operating income adjustments and in determination of the unadjusted test year operating income that was used as the starting point of the proposed overall pro forma test year operating income in this case. Doing one without the other would result in an increase in the revenue requirement, which is wrong given that the effective tax is an income tax decrease from the standard tax rate.[14]

The specific items that require adjustment to reflect the effective tax return are detailed on page 24 of Henkes Direct. Not all of those adjustments have been reflected in the AG's testimony, however, because the AG did not have the data necessary to do so.[15]

B. Interest Synchronization

Both the AG and LG&E are agreed on the use of and manner of calculating their respective pro forma synchronized interest expense levels. But, the data used by LG&E to calculate the adjustment is wrong. It used $24.315 million rather than the $23.209 that should have been used. Utilization of the correct data results in a increase of the Company's pro forma electric test year after tax operating income by $442,000.[16]

[13] Henkes Direct, pp. 21-23.
[14] Henkes Direct, p. 26.
[15] Henkes Direct, p. 25.

[16] Henkes Direct 27-29.

C. Unbilled Revenues

LG&E removed unbilled revenues of $22.895 million from the test year ending 9/30/03 representing 414,294,000 KWHs worth of electric service rendered during the test year ending 9/30/03 and has replaced them with $21.028 unbilled revenues that were on the books from the beginning of the test year representing 410,199,000 KWHs of serviced rendered prior to the test year but which were not billed until the test year. This results in removing revenues of $1.867 million of revenue associated with 4,095,000 KWH of service rendered during the test year, while leaving the operating expenses associated with that service in the test year. Consequently, there is a mismatch of expense and revenues associated with the same hours of service. Therefore, the operating expenses should be reduced so that the revenues and the expenses for the test year match. Using an Operating Expense Ratio of 56%, the adjustment results in an increase to operating income of $624,000.[17]

D. Customer Growth Revenue Annualization

The Company used a 12-month average test year number of customers in computing its adjustment to reflect the annualized impact on test year net operating revenues of customer growth experienced during the test year. This must be corrected to reflect a 13-month average test year customer level rather than a 12-month average even under the method used by LG&E.[18]

Furthermore, given the fluctuations in electrical customers experienced by LG&E from month to month, it would be more appropriate to calculate the customer growth using the methodology accepted by the Commission in *In the Matter of: An Adjustment of the General Rates of Delta Natural Gas Company, Inc.*, Case No 97-066, as a means to better match test-

[17] Henkes Direct, pp. 30-32 and Schedule RJH 6.

[18] Henkes direct, p.p. 32-33.

year-end plant to customer level in the face of month to month fluctuations in the customer level[19] whereby one first calculates an average annual compound growth rate for each of the Company's customer classes during a recent historic period, including the test year, and then uses one-half of this average annual compound growth rate to represent the appropriate customer growth rate within the test year. This half-year growth rate is then applied to the average test year number of customers for each customer class to arrive at the appropriate test year-end customer growth adjustment number.

Using the residential class as an example, that class being the only class for which LG&E was able to provide the requisite data,[20] showed that LG&E's methodology produces a year-end customer growth adjustment of 1,738 while the methodology recommended by the AG produces a test year-end customer growth adjustment of 2,191. This produces a revenue increase adjustment of $1.433 million,[21] which is then offset with associated operating expenses by applying LG&E's proposed Operating Expense Ratio to the revenue adjustment amount. This produces a net test year operating revenue adjustment of $1.436 million which increases the proposed pro forma after-tax electric operating income of LG&E by $167,000.

Because the absence of data precluded the utilization of this methodology for the other classes, the revenue adjustments as calculated by LG&E were adopted, but it is recommended that the customer growth revenue annualization calculation approach be used for all customer classes in the next base rate case.[22]

E. Promotional Expenses

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[19] *In the Matter of: An Adjustment of the General Rates of Delta Natural Gas Company, Inc.*, Case No 97-066, 8 December 1997, p. 10-11.
[20] Henkes Direct, pp. 37-38.
[21] Henkes Direct 37 and Schedule RJH-7.
[22] Henkes Direct, p. 37, 39.

The AG recommends that LG&E be required to remove promotional expenses consisting of $22,699 included in account 909001, $3,119 of expenses in account 909002, and $64,632 in accounts 912001 and 912005 which LG&E self-characterized as promotional (indicating the expenses are to promote or retain the use of services by present and prospective customers) but which it seeks to charge to ratepayers as Economic Development Research and Marketing Management.[23]

On Cross-examination counsel suggested that inasmuch as economic development brings a benefit to the state as a whole and as the Companies agreed to merger related conditions to continue to support economic development, it would be appropriate to assess these expenses to ratepayers.[24] First, the merger conditions were intended to be a benefit to the ratepayers, not an added expense relating from the change in treatment of promotional expenses just because they comply with the agreement of the Companies to maintain their efforts. Second, promotional expenses are defined by regulation and the requirement that they be eliminated is mandated by regulation. As such, the regulation has the effect of law whose application and reach cannot be changed by the conditions imposed in the mergers. Therefore, these expenses, which clearly fall within the ambit of 807 KAR 5:016, Section 4, should be disallowed. Furthermore, removal of these expenses is consistent with what was done in LG&E's last rate case.[25]

Disallowing these expenses produces an increase of LG&E's after-tax operating income of approximately $54,000.[26]

F. Rate Case Expense

[23] Henkes Direct, pp.39-41.
[24] TE, Vol. III, pp. 113-118.
[25] Case No. 2000-00080.
[26] Henkes Direct, p. 41.

As updated at the time of the filing of the AG's testimony, the Company was estimating rate case expenses of approximately $1.170 million. As Mr. Henkes points out, the fact that LG&E filed both a gas and an electric case means that at least some of the rate case expenses such as advertising could be shared and that the combined expenses for the two cases seems inordinately high. Further the expenses are high when compared to the expenses estimated and experienced in the most recent gas case, Case No. 2000-00080.[27]

Following established Commission policy, rate recognition should be given to all actual rate case expenses prudently incurred[28] and those should be amortized over a three year period. At the time the testimony was filed, those expenses were $324,000. This adjustment increases the pro forma test year after-tax electric operating income of LG&E by $135,000.

G. Injury and Damage Expense Normaliztion

The Company proposes use of a 5-year average of the CPI-adjusted Injury and Damage ("I&D") expenses in lieu of the test year I&D expense. This is reasonable except that the years included in the five year average need to shift forward so that the test year amounts are covered. LG&E's proposal runs from 1998-2002 and it is more appropriate to run form 1999-2003 as that will cause the normalized average expense to be based on the most recent actual data through the end of the test year. The impact is to increase LG&E's proposed pro forma test year electric after-tax operating income by $43,000.[29]

G. IT Staff Reduction Cost Savings

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[27] Henkes Direct, p. 42.

[28] Because the expense such as advertising, counsel, and personnel utilized in conducting and memorializing negotiations as well as consultants, printing and mailing were common to both the electric case and the gas case, special care needs to be taken to assure that the gas case expenses are not simply assigned to the electric case as the one ultimately fully litigated. The gas settlement did not occur until May 12, 2004, well after most of the litigation expense had been incurred. It is therefore, appropriate to see to it that the gas case bears its share of the litigation expense.

[29] Henkes Direct, pp. 44-45.

LG&E has reduced its test year operating expenses to reflect, in part, the October 2003 reduction of 27 IT staff personnel and has partially offset the cost savings by the 3-year amortization of the Cost to Achieve the savings. Though the company reflected the payroll, payroll tax and 401(K) cost savings associated with these staff reductions, it did not reflect the savings for Team Incentive Awards ("TIA") and other employee benefits such as pension, FAS-106, long term disability, and medical, dental and life insurance. LG&E has confirmed that these will amount to another $306,990. Seventy nine percent of that is attributable to the electric operations of LG&E. These added cost savings increases LG&E's proposed pro forma test year electric after-tax operating income by $146,000.[30]

H. Obsolete Inventory Write-off

During the test year LG&E wrote off $2.061 million of obsolete inventory for its steam plants which it proposes to charge to the ratepayers on a three-year amortization basis. The obsolete inventory write off is a non-recurring event and as such should be fully removed from the test year. It would be inappropriate to put an item that has been written off back on the books in a deferral account to enable future amortization of the deferral to ratepayers.

Furthermore, including this one time event in the ratemaking consideration while simultaneously excluding items such as the Cane Run Repair insurance refund from ratemaking consideration as a non-recurring item would not be appropriate or consistent. As non-recurring items, neither the obsolete inventory write off nor the insurance refund reflects a representative level of annual expenses for ratemaking purposes. Therefore, it is appropriate that, like the insurance refund, the obsolete inventory write-off be excluded.[31]

[30] Henkes Direct, p. 46.

[31] Henkes Direct, pp. 46-47.

This adjustment increases LG&E's proposed pro forma test year electric after-tax operating income by $411,000.

I. Carbide Lime Write-Off

As a result of the bankruptcy of a supplier, LG&E paid for but did not receive $2.125 million worth of Carbide Lime inventory. It proposes to recover the Carbide Lime write-off from the ratepayers on a going forward basis using a three-year amortization period for the expense. This too is a non-recurring event that does not reflect a representative level of annual expense for ratemaking purposes. The proposed expense should be disallowed.

Disallowance of this expense results in a $424,000 increase to LG&E's proposed pro forma test year electric after-tax operating income.[32]

J. Miscellaneous Adjustments

$17,957 worth of allocated electric donation expenses were erroneously left in the test year electric operating expenses and need to be removed.[33]

A total of $118,805, of employee gifts expenses, award banquets, parties and other social events are included in the test year. Commensurate with past Commission practice, at least half of these, $59,403, should be removed.[34]

$140,000 of the total $195,401 EEI expenses that have been included in the test year electric operating expenses of LG&E should be excluded. These represent 72% of the total of EEI expenses that have been included, and the evidence shows that 72% of EEI's activities are related to lobbying, advertising, and marketing and public relations that bring no benefit to the ratepayers of LG&E.[35]

[32] Henkes Direct, pp. 48-49.
[33] Henkes Direct, p. 49.
[34] Henkes Direct, pp. 49-50
[35] Henkes Direct, p. 50.

An adjustment of $5,472, reflecting the additional ECR Roll-In that took place on Decembers 11, 2003, has been made to LG&E's originally proposed ECR Roll-In adjustment. This reduces the proposed base revenue adjustment shown in Rives Schedule 1.03.[36]

The total impact of the miscellaneous adjustments is to increase LG&E's proposed test year electric after-tax operating income by approximately $127,500.[37]

K. FASB 143 Asset Retirement Obligation Adjustment

Based on the rebuttal testimony of Ms. Scott, the issue pertaining to the FASB 143 is resolved and the testimony is, therefore, withdrawn. This removes a $3.149 million increase to the Company's proposed test year electric after-tax operating income found in the direct testimony.

L. Depreciation Expense

The depreciation rates discussed below, when applied to the depreciable plant in service balances at the end of the test year, produce $22.335 million lower annualized depreciation expenses than those proposed by LG&E. This has the result of increasing LG&E's proposed pro forma test year after-tax electric operating income by $13.375 million.[38]

M. Other Expense Issues

Should the Commission accept the recommendation of Mr. Majoros concerning the treatment of pension and Other Post-Employment Benefit ("OPEB"), consistent treatment of that issue for LG&E would result in a decrease in the operating income of LG&E's proposed pro forma test year electric operating expenses of $4.755 million.[39]

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[36] Henkes Direct, p. 50.
[37] Henkes Direct, p. 51.
[38] Henkes Direct, pp. 38-39.

[39] Henkes Direct, p. 55.

REVENUE CONVERSION FACTOR

The LG&E revenue conversion factor of 0.5924 incorporates a Kentucky state income tax rate of 8.25% while the AG's recommended conversion factor of 0.5948 incorporates the Kentucky state income tax rate of 7.87% in accord with the recommendation that effective state tax rate be used. If the effective state income tax rate is adopted, the AG's recommended conversion factor should be used.[40]

DEPRECIATION ISSUES

On behalf of LG&E and KU, Mr. Earl Robinson sponsored depreciation studies that result in an $8,681,141 increase in electric plant depreciation expense and a $1,428,511 increase in common plant depreciation expense for LG&E, and a $3,949,872 increase in depreciation expense for KU, based on plant and accumulated depreciation as of December 31, 2002.[41] These increases result from shorter service lives and greater negative net salvage ratios. These increases are not warranted and provide an undue and unreasonable increase in the revenue requirements of LG&E and KU. The increases should be denied.

Depreciation expense is included in the revenue requirements of KU and LG&E, and is passed on to ratepayers on a dollar for dollar basis. Annual depreciation expense is calculated by applying depreciation rates, which are calculated in depreciation studies, to plant investment. In general, there are two components associated with the recovery of investment in plant -- the recovery of invested capital (money already spent) and the treatment of the estimated cost of removing the asset at the end of its useful life (money not yet spent).

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[40] Henkes Direct, p. 55.
[41] Majoros Direct Testimony for both companies pertaining to Depreciation (hereinafter Majoros Direct), p. 4. Because the revenue requirements for the gas operations of LG&E are subject to the partial settlement, this does not address the portion of the depreciation that entails gas only.

The principle depreciation issue in these proceedings is the ratemaking treatment of the second component of plant investment recovery – the estimated cost of removing the retired investment, or future net salvage. KU and LG&E have included approximately $45 million[42] in estimated cost of removal expense in their annual depreciation expense proposals, despite the fact that their average annual net salvage experience is only $1.78 million for LG&E[43] and a positive $2.2 million for KU.[44] In other words, they propose to charge ratepayers $45 million per year, even though they are experiencing on average, $439 thousand[45] in positive net salvage. In addition, the Companies have already collected $419.5 million for cost of removal expenditures which they have not yet, and may never, incur.[46]

Furthermore, the Companies' net salvage proposals do not conform to the recent FERC Order No. 631. The Companies' collection for net salvage should be separately identified in depreciation expense and accumulated depreciation. This can be accomplished by removing the future net salvage estimates from the depreciation rates and adopting a net salvage allowance, as recommended by Mr. Majoros.[47] In addition to being a more realistic estimate of net salvage, this will bring the Companies into compliance with the "separation principles" of FERC Order No. 631.

Mr. Majoros also disagrees with the Company on several of the plant lives used to calculate the depreciation rates.[48] As will be demonstrated below, the Commission should adopt Mr. Majoros' proposed lives for these plant accounts.

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[42] Majoros Direct, p. 24. This amount does not include LG&E gas depreciation.
[43] Majoros Direct, p. 24. Amount does not include gas depreciation.
[44] Majoros Direct, p. 24. As will be discussed later in the brief, the Company has disputed Mr. Majoros' calculation of KU's net salvage experience. TE, Vol. III, pp. 40-41, 158.
[45] Original amount of negative $53 thousand included LG&E gas net salvage. Majoros Direct, p. 24.
[46] Majoros Direct, p. 28. Original amount of $456 million has been adjusted to remove cost of removal related to gas plant.
[47] Majoros Direct, p. 26.
[48] Majoros Direct, p. 6.

Net Salvage

Net salvage is the difference between gross salvage and the cost of removal of the plant. Gross salvage is the amount recorded due to the sale, reimbursement, or reuse of retired property. The cost of removal is related to the disposal of retired plant.[49] When gross salvage exceeds the cost of removal, the net salvage is positive. If cost of removal exceeds gross salvage, the resulting net salvage is negative. When net salvage estimates are included in depreciation rates, positive net salvage decreases the deprecation rate, and resulting depreciation expense. Negative net salvage increases the depreciation rate and expense.

In all businesses, depreciation expense is a charge to operating expense that reflects the recovery of a company's previously expended capital.[50] This allows the company to reimburse shareholders for outlays of capital used to purchase an asset, over the life of that asset. In businesses other than public utilities, the cost of removing or disposing of an asset when it is retired from service (cost of removal) is recognized as an operating cost in the year the expense is incurred.[51] Public utilities are unique in that they charge the cost removal of an asset to the accumulated depreciation reserve[52] on an estimated basis, thus allowing that cost to be collected over the life of the asset rather than recognizing the actual expense of the retirement in the year it occurs.[53] As such, for public utilities, depreciation reserve includes both capitalized amounts to reimburse the shareholders for monies already expended (the original cost) and to "reimburse" shareholders for monies yet to be expended (the negative net salvage, or cost of removal). This

[49] Majoros Direct, p. 19.
[50] Majoros Direct, p. 7.
[51] Majoros Direct, p. 12.
[52] The accumulated depreciation reserve is a record of all previously recorded depreciation expense, both the cumulative annual straight-line recovery of the original cost of the plant and the net salvage that has been recovered to date. Majoros Direct, pages 8-9.
[53] Majoros Direct, pages 12-13.

is in contrast to other businesses whose depreciation reserve represents only reimbursement of amounts already spent.

"Reimbursement" of the estimated future negative net salvage portion of depreciation expense is actually prepayment of an inflated expense by ratepayers. This prepayment is problematic for four reasons: the Companies do not have any actual liabilities or requirements to spend the money; the cost of removal has to be estimated many years before the expense will be incurred; the estimate may include the cost of procedures that are not performed when the time for retirement/disposal arrives; and the net salvage estimates include inflation.

In these proceedings, the Companies' estimated future net salvage ratios, which they have included in their depreciation proposals, result in a substantial mismatch between what the Companies propose to collect for negative net salvage, and what they have actually expended for net salvage. The Companies included $45 million for negative net salvage in their depreciation proposals.[54] However, over the five-year period ending December 2002, the Companies averaged $439 thousand in annual positive net salvage.[55] While LG&E experienced negative net salvage of $1.78 million, Mr. Majoros' analyses indicate that KU experienced, on average, positive net salvage during that period. It should be noted that in rebuttal and cross-examination, the Company disputed Mr. Majoros' calculation of the average net salvage experienced by KU, claiming the amount should be a negative $1.58 million instead of the positive $2.2 million calculated by Mr. Majoros.[56] However, Mr. Majoros used the Companies' own data in his

[54] Majoros Direct, page 24. This amount does not include LG&E gas depreciation. This number was sorted out only after the hearing was concluded as the negotiations concerning gas were completed just before the hearing commenced. This corresponds to the $49 million referenced in the hearing.

[55] Majoros Direct, page 24. The amount does not include LG&E gas depreciation.

[56] TE, Vol. III, pp. 40-41, 158.

calculations, and as such he has not conceded on his original calculation and resulting recommendation.

Part of the mismatch between the Companies' proposals and reality is due to the inclusion of future inflation in the estimates of future net salvage expense. The type of net salvage studies performed by the Company has lead to exorbitant current charges to current ratepayers for inflated future cost of removal.[57] As Mr. Majoros points out, "there is a fundamental mismatch between the dollars associated with the installation dates of the assets and the dates they are removed from service."[58]

Because the Companies' net salvage expense is estimated, and is estimated in end-of-life dollars, it is an inflated estimation. The inflation that is expected to occur between the time the asset is put into service and the time it is retired is included in the end-of-life dollars used for the estimated expense.[59] Under this process, the shareholder recovers the inflated estimated future cost of removal, a cost that includes the time-value of money through its recognition of inflation. Once the depreciation expense, inclusive of the pro rata share of the inflated future net salvage, has been collected from the ratepayer, the shareholder can then invest that and again earn the time-value of money until such time as the future expense is incurred, if ever. Alternatively, the Company is free to spend the excess cash on whatever it may choose, unregulated businesses for example.

In 2001 the Financial Accounting Standards Board ("FASB") adopted the Statement of Financial Accounting Standards No. 143 ("SFAS 143"). This standard sets forth the treatment of Asset Retirement Obligations (AROs) for financial statements issued for fiscal years beginning

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[57] Majoros Direct Testimony pertaining to ARO and SFAS 143 (hereinafter Majoros Direct, ARO and SFAS 143), p. 22.
[58] Majoros Direct, ARO and SFAS 143, p. 21.
[59] TE Vol. III, pp. 43; 39-40.

on or after June 15, 2002. SFAS No. 143 now constitutes Generally Accepted Accounting Principles ("GAAP"). On April 9, 2003, the Federal Energy Regulatory Commission ("FERC") adopted the provisions of SFAS No. 143 and integrated it into the USOA in its Order No. 631.[60]

SFAS No. 143 (and FERC Order No. 631) require companies to review their long-lived assets to determine whether or not they have actual legal obligations to remove those assets upon retirement.[61] Such obligations are referred to as "Asset Retirement Obligations" ("AROs"). If a company has an ARO, the ARO is considered to be a part of the cost of the asset and recorded as such. However, only the net present value is recorded, not the inflated future value.[62]

KU and LG&E have reported that they do have certain AROs and they have recorded these AROs on their financial books. However, for the majority of plant, the Companies do not have legal AROs. In other words, the Companies do not have any legal obligations associated with the removal of this plant upon retirement. They could choose to completely remove the plant, they could retire it in place, or they could refurbish the plant and continue to use it. Whatever the Companies ultimately choose to do, the fact exists that for most of their plant, there is no legal requirement for the Companies to expend money on future cost of removal. Regardless of this fact, the Companies have included estimates for this future cost of removal in their depreciation rate proposals.

For assets for which there is no legal retirement obligation, the "non-legal" AROs, the net salvage estimate may well be predicated on a level cost of removal expense that will never be incurred. For instance, in contrast to the decommissioning of plants such as nuclear facilities, where the decommissioning procedure is clearly spelled out and the utility is legally obligated to

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[60] Majoros Direct, ARO and SFAS No. 143, p. 9.
[61] Majoros Direct, SFAS No. 143, p. 5.

[62] Majoros Direct, SFAS No. 143, p. 5.

follow the procedure, there is often no legally required procedure with reference to other types of plants.[63] Because the Company has no legal obligations associated with the retirement of these assets, it is entitled to engage in least-cost retirement practices. This is the case even though it has included in its depreciation calculations estimated retirement costs to recover the costs of any eventuality.[64] For instance, plant decommissioning estimates based on a presumed return to "Greenfield" status will far outpace the actual removal cost if the plant is merely "retired in place."

In the case of KU and LG&E, this is what seems to have occurred. The Companies estimate that $419.5 million[65] of excess cost of removal expense is currently in the depreciation reserve. The accumulated depreciation reserve, also called the accumulated deprecation account, is the record of previously recorded depreciation expense and represents the net accumulated amount of the original cost of assets and net salvage that has been recovered from ratepayers to date.[66] This $419.5 million represents dollars collected from ratepayers for cost of removal expense that simply has not occurred. If the type of mismatch between the average actual retirement expense experienced by the Companies and the amount of negative net salvage included in the depreciation rates has been as pronounced in the past as it is now, it is not difficult to see how such a build up of negative net salvage in the accumulated depreciation account has occurred. Furthermore, this build up has occurred despite the retirement of nine steam-generating plants by LG&E since 1979 and of five steam-generating plants by KU since

[63] TE Vol. III, pp. 146-148.
[64] TE Vol. III, pp. 158-159.
[65] Majoros Direct, p. 28. Amount does not include cost of removal related to LG&E gas plant.
[66] Majoros Direct, p. 9.

1964.[67] These were presumptively major retirements and should have reduced the accumulated reserve (and collected future cost of removal) by a substantial amount.

SFAS No. 143 does not specify how net salvage is to be calculated with regard to non-legal AROs. However, it does require companies to determine the amount of any prior cost of removal collections relating to non-AROs currently included in accumulated depreciation and record these, and future such charges, as a regulatory liability to ratepayers.[68] The Companies' calculation of the $419.5 million was in response to this very requirement. Furthermore, FERC Order No. 631 requires separation of previous and current accumulated removal costs for other than legal retirement obligations.[69]

The Companies' depreciation proposals do not conform with the requirement of FERC Order No. 631 to separately account for cost of removal collected. The Companies net salvage amounts are not specifically identifiable; they can only be estimated, since they are bundled into the proposed depreciation rates and will change each year as plant balances change.[70]

Due to the substantial mismatch between the Companies' proposals and reality, and the failure of the proposals to follow FERC Order No. 631, the net salvage component of the Companies' depreciation rates should be removed. Instead of collecting estimated net salvage in depreciation rates, the Commission should require the use of an annual net salvage allowance for each company. This allowance is based on the actual five-year average experience of each company and as such is firmly grounded in reality.[71]

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[67] Robinson Rebuttal, p. 5.
[68] Majoros Direct, ARO and SFAS No. 143, p. 8.
[69] Majoros Direct, ARO and SFAS No. 143, p. 18.
[70] Majoros Direct, p. 28.

[71] Majoros Direct, p. 26.

For KU this allowance is $0. This is because KU has on average experienced positive net salvage. In other words, in spite of their request for $23.5 million in negative net salvage annually, they actually receive $2.2 million in positive net salvage on average. Recognizing that this situation could change, Mr. Majoros recommends a net salvage allowance of $0 for this Company. For LG&E the net salvage allowance is $1.78 million, which reflects that LG&E has on average experienced $1.78 million in negative net salvage.[72]

As the use of a net salvage allowance results in a specifically identifiable amount, it meets the requirements of FERC Order No. 631.[73] It allows the Companies to account for collected cost of removal separately as required by this Order. It insures that the Companies will recover the present value of its actual cost and will eliminate the inclusion of future inflation in depreciation rates.[74] In addition, it will allow the Commission to compare the actual cost of removal expense incurred by the Companies, with the cost of removal amounts they collect from their ratepayers.

This normalized net salvage allowance approach has been used by the Pennsylvania Public Utility Commission for many years. In addition to being utilized in Pennsylvania, beginning in 2001 is has been used by this Commission and by Missouri Public Service Commission and the New Jersey Board of Public Utilities.[75]

The Companies bear the burden of proving that an increase in depreciation expense is just and reasonable under KRS 278.190 (3). While they rely heavily on the fact that Mr. Robinson has calculated depreciation rates in the same manner as many utilities do, they ignore the recent reconsideration of this practice as evidenced by the issuance of SFAS No. 142 and FERC Order

[72] This amount excludes net salvage related to gas plant.
[73] Majoros Direct, page 29.
[74] Majoros Direct, p. 31.
[75] Majoros Direct, pp. 30-31.

No. 631. Simply demonstrating that the expense is being estimated using a system that has been used by many utilities and Commissions is not sufficient when major discrepancies appear and persist. Here, there is certainly no match of the Companies' predictions with the controlling test of experience for these companies today.[76] As the Court pointed out in Lindheimer as long ago as 1934,

> "[t]he determination involves the examination of many variable elements and **opportunities for excessive allowances, even under a correct system of accounting, [are] always present**. The necessity of checking the results is not questioned. **The predictions must meet the controlling test of experience."** [Emphasis added.][77]

Because the Companies' net salvage amount is bundled into the proposed depreciation rates and will change each year as plant balances change, the amount can only be estimated rather than specifically identified, as required in FERC Order No. 631.[78] Regardless, it is clear that under this proposal, if it is not adjusted to bring the results into line with reality, ratepayers will over pay for future net salvage, at a minimum, by the amount of the inflated future estimates. Further, as is evident by the $419.5 million of excess cost of removal now held in the accumulated depreciation account, they will pay for expenses that are never incurred.

Therefore, the Companies' proposal should be denied. The retirement expense for those assets for which there is no legal retirement obligation should be accounted for separately, as specifically identified allowances, within depreciation expense and accumulated depreciation. The net salvage expense should be a normalized net salvage allowance based on the average of the most recent five years worth of actual net salvage activity.

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[76] See, Lindheimer v. Illinois Bell Telephone Company, 292 U.S. 151, 168-179 (1934).
[77] Ibid.
[78] Majoros Direct, p. 28.

Alternatively, if a future net salvage is used, it should not be an inflated net salvage, but rather, should be discounted to net present value.[79] In this way, the Companies will not recover the effects of inflation twice, once in calculating the allowance and again through investment of the funds until such time as they are called upon for removal expense.

Finally, the $419.5 million of overstated depreciation reserve should be returned to the ratepayers by reducing depreciation expense to reflect an amortized return over 10 years.[80] Of that $419.5 million, $235.1 million has been collected from KU's Kentucky customers and $13.4 million from its Virginia customers. $171 million has been collected from LG&E's customers for future cost of removal relating to non-legal AROs.[81]

Service Lives

The life spans Mr. Robinson used in the calculation of depreciation rates for steam production plant are too short - only 48 years. The National Study of U.S. Steam Generating Unit Lives – 50 MW and Greater conducted by Mr. Majoros and his firm finds that steam generating units of 50 MW or greater are experiencing life spans of approximately 60 years.[82] Nevertheless, because of the agreements entered in Cases No. 2001-140 and 2001-141, Mr. Majoros accepted the life spans proposed by Mr. Robinson, even though they are too short.

Although Mr. Majoros has accepted the Companies' proposed life spans for production plant, along with most of the proposed mass property plant lives, he disagreed with the life spans for four of LG&E's accounts and for seven of KU's accounts, based on the results of further

[79] Mr. Robinson agrees that the Companies' proposed rates incorporate future inflation into the net salvage estimates and do not reduce the estimated future net salvage ratios to present net value. TE Vol. III, p. 48.
[80] Majoros Direct, ARO and SFAS 143, p. 23.
[81] Majoros Direct, ARO and SFAS 143, p. 21. LG&E amount does not include cost of removal related to gas plant.
[82] Majoros Direct, p. 33.

analyses.[83] The specific accounts and recommendations are detailed in Majoros Direct from pages 43 through 51 for LG&E and from pages 46-48 for KU.

At the hearing, Mr. Robinson appeared to agree with Mr. Majoros in many instances, as demonstrated in cross-examination. Mr. Robinson complained about Mr. Majoros' use of the Geometric Mean Turnover method of life analysis in addition to the more refined SPR and Actuarial methods. However, Mr. Robinson ultimately conceded that Mr. Majoros had conducted three analyses for each account whereas he, Mr. Robinson, only conducted two. The selection of lives comes down to an issue of credibility: which expert is the more credible judge of lives? Even a superficial review and comparison of Mr. Majoros' study versus Mr. Robinson's reveals that Mr. Majoros has much more credibility.

Mr. Majoros calculated depreciation rates for LG&E, which are shown on Statement A of the Electric Division and Common Division sections of Exhibit __(MJM-3) and for KU, which are shown on Statement A of Exhibit___(MJM-4).[84] Mr. Majoros used Mr. Robinson's spreadsheets to calculate his recommended rates to insure that the mechanics of the calculations involving production plant stay the same between the two studies. In so doing, he found inconsistencies which he corrected.[85]

Mr. Majoros' recommendations result in an \$82.5 million depreciation expense accrual for LG&E, based on plant and accumulated depreciation as of December 31, 2002.[86] Of this, \$7.3 million relates to gas plant.[87] For KU, Mr. Majoros' recommendations result in a \$67.0 million depreciation expense accrual, based on plant and accumulated depreciation as of

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[83] Majoros Direct, p 42. Majoros also disagreed with 4 gas accounts which are not discussed given the partial settlement entered into by the Attorney General pertaining to LG&E's gas rates.
[84] Majoros Direct, p. 49.
[85] TE Vol. III, pp. 43-44.
[86] Majoros Direct, page 50.
[87] Majoros Direct, Exhibit___(MJM-3), Gas Division, Statement A.

December 31, 2002.[88] These recommendations are $22.1 million[89] and $32.2 million less, respectively, than the Companies proposals.[90]

COST OF EQUITY:

A. Rosenberg's recommended return on equity of 11.25% for the LG&E and KU electric operations should be rejected.

Robert Rosenberg recommended that LG&E and KU be allowed a return on equity of 11.25%, the upper end of his recommended range of return of 10.75-11.25% for their electric operations.[91] This recommendation was based on his DCF analysis, CAPM analysis, Risk Premium Analysis and Comparable Earnings analysis that was then combined with a suggestion that the highest end of the range should be awarded in recognition of the efficiency of the operations of the companies. Rosenberg's recommendation should be rejected for a variety of reasons.

First, studies are only as valid as the information utilized. Three of the thirteen companies used by Rosenberg to obtain data for his cost of equity study do not meet his own selection criteria or are dissimilar to LG&E and KU. Both Consolidated Edison and CH Energy were used by Rosenberg in his proxy group though both were involved in major merger activity[92] despite the fact that his criteria indicated that companies would be excluded from the proxy group if they are currently involved in any major merger activity.[93] The third company, NSTAR, unlike LG&E

[88] Majoros Direct, page 50. This amount includes a $1.58 million allowance for net salvage.
[89] Excluding gas depreciation.
[90] Majoros Direct, page 50.
[91] Direct Testimony of Robert G. Rosenberg for LG&E (hereinafter Rosenberg Direct LG&E,) pp. 51-53 and Direct Testimony of Robert G. Rosenberg for KU (hereinafter Rosenberg Direct KU), pp. 48-50
[92] Consolidated Edison is involved in a merger dispute with Northeast Utilities, a major merger activity. Therefore, it should not have been used. See, Weaver Direct Testimony, page 30, line 1. CH Energy has been discussed in the financial press as a potential acquisition target and its stock price may reflect an acquisition premium. See, Rosenberg Direct LG&E, p. 23, footnote 4. The acquisition of a company is major merger activity.
[93] Rosenberg Direct LG&E, p. 15, line 6 and KU, p. 12, line 5.

and KU, owns no generation and is, therefore, not an appropriate proxy.[94] These three companies represent 23% of the proxy group and render data from that group unreliable.

Second, Rosenberg went through complicated and wholly unnecessary calculations and estimations in order to establish an estimated GDP "nominal" growth rate that is nearly 1% higher than the readily available published nominal rate of growth in GDP for use in his two-stage DCF analysis, thereby creating an artificially high two-stage DCF result.

Rosenberg estimated a 2008 value for the GDP Chain-Type Price Index by interpolation, estimated a 2008 value for the GDP Real Gross Domestic Product by interpolation and estimated a 2008 value for the Consumer Price Index by interpolation.[95] He also estimated a 2008-2025 annual percentage growth rate for the GDP Chain-Type Price Index, estimated a 2008-2025 annual percentage growth rate for the Real Gross Domestic Product and estimated a 2008-2025 annual percentage growth rate for the Consumer Price Index.[96] He averaged his estimated 2008-2025 annual growth in the GDP Chain-Type Price Index, called the GDP Deflator, with his estimated 2008-2025 Consumer Price Index annual growth to estimate a conversion factor for converting the "real" GDP growth into a "nominal" GDP growth. He also used these estimates to further estimate a GDP "nominal" growth rate of 5.91%.[97]

The estimates were unnecessary. The nominal rate of growth in GDP is readily available from Value Line, the Congressional Budget Office and the Office of Management and Budget.[98] The average growth rate in nominal GDP that was published in August 2003 for the years 2008 through 2013 was 5.0%, nearly 1% below Rosenberg's estimated and calculated 5.91%. Mr.

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[94] Carl Weaver filed a single set of direct testimony for both companies. Page and line references are common to both companies. Direct Testimony of Carl Weaver for LG&E and KU (Hereinafter Weaver Direct), p. 29, line 19.
[95] Transcript of Evidence, p.96.
[96] Rosenberg Response to AG data request 1-16(c) to KU, p. 1.
[97] Rosenberg Response to AG data request 1-16(c) to KU, p. 1.
[98] Weaver Direct, p. 7, line 21.

Rosenberg agreed that if he had used a lower growth rate, his two-stage DCF result would have been lower. [99]

Third, Rosenberg's two-stage DCF result using a sustainable growth estimate is skewed and the average is overstated. The result should be rejected. As previously discussed, three of the thirteen companies used to establish the average of sustainable growth should have been excluded because they fail to meet his criteria or are dissimilar to LG&E and KU. Further, Rosenberg rejected use of the result of CH Energy in establishing the average because it was too low, at 140 basis points below the next higher result, but included Exelon in the average though its results were 190 basis points higher than the next highest outcome,[100] thereby rejecting the outlier that would have lowered the average but including the outlier that raised the average.

Fourth, the results of Rosenberg's "empirical" CAPM should be rejected because the model is not correctly specified and therefore, serves only to improperly increase beta. Rosenberg says his empirical CAPM is also known as the zero-beta CAPM or two-factor CAPM.[101] Mr. Rosenberg acknowledged on cross-examination that his model does not use the two factors[102] of the Fisher Black zero-beta CAPM. Instead of the using two factors specified in Black's model, Rosenberg uses the same factor[103] twice in the equation which serves to artificially increase beta.

Fifth, Rosenberg's CAPM results are too high as a result of his addition of a mid-capitalization or small-capitalization adjustment. The addition of these adjustments, whose very

[99] Transcript of Evidence, p. 100.
[100] Transcript of Evidence, pp 100-103.
[101] Rosenberg Direct LG&E, p. 27, footnote 5.
[102] A zero-beta expected market risk premium and a normal expected market risk premium are both factors in the zero-beta CAPM. See, "Capital Market Borrowing with Restricted Borrowing," *Journal of Business*, 45 (July 1972), 444-455. Attorney General Cross Exhibit 1.
[103] Rosenberg uses RP, an expected market risk premium twice in his model and does not use a zero-beta expected market risk premium. (Rosenberg Direct LG&E, p 28, line 5).

purpose is to reflect market inefficiencies, is contrary to the function of a CAPM analysis as the CAPM is built on the premise that the market is efficient.[104]

Sixth, the results of Rosenberg's second risk premium model should be rejected because the model is flawed and fails to produce logical results.[105] Rosenberg's risk premium model shows that common stock risk premiums are smaller when bond returns are higher,[106] but Rosenberg's data shows the opposite is true. Per Rosenberg's data, in the period from 1931 through 2003, annual income returns on long-term government bonds were highest in the period of 1981 through 1985.[107] The average return for the period 1981-1985 was 11.68% while for the entire 1931-2003 period the average return was 6.70%. Per Rosenberg's data, the market return on Moody's Commons Stock Index for the 1981-1985 period was 24.14% as compared to an average return for the entire 1931-2003 period of 11.27%. The premium for the 1981-1985 period, when bond returns were highest, was 12.44% which is higher than the 4.57% average premium over the entire 1931-2003 period. Thus, Rosenberg's data demonstrates that his second risk premium model results are not reliable and should be rejected.

Seventh, Rosenberg's comparable earnings analysis should be rejected because the 208 companies he used are not comparable to LG&E and KU. Rosenberg's selection criteria for the 208 companies used in his "Comparable Earnings Analysis" should have included all of the electric companies he used for his data samples "Electric Companies Group" if they were comparable to LG&E and KU. Only five of the 13 electric companies used for the "Electric

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[104] Weaver Direct, pp. 17-18, beginning at line 6.
[105] Weaver Direct, p. 20, line 14.
[106] Weaver Direct, p. 21, line 12.
[107] Rosenberg Rebuttal testimony filed for LG&E (hereinafter Rosenberg Rebuttal LG&E), Rebuttal Workpapers, page 84 of 130.

Companies Group" are included in the 208 companies used for the "Comparable Earning Match."[108]

Finally, Rosenberg's suggestion that LG&E and KU should be awarded the highest return on equity present in a range of returns as a means of recognizing that the management of the companies is highly efficient and to eliminate the inverse relationship between risk analysis equity awards and the efficiency of management[109] should be rejected. Just as a reasonable rate of return may not be lowered in order to penalize bad management,[110] it may not be raised to reward efficient management. The return on equity is not an incentive. Rather, it is that which allows the companies to maintain financial integrity assuming efficient and economical management, to attract capital, and to compensate investors for the risks assumed.[111] Rosenberg's suggestion flies in the face of the reason and purpose of the cost of equity analysis.

<u>B. Weaver's recommended return on equity of 10.25% for the electric operations of LG&E and KU should be accepted.</u>

Much of the rebuttal return on equity testimony of Rosenberg was devoted to an effort to discredit Dr. Weaver's return on equity recommendation of 10.25%. Rosenberg's challenges contain a variety of errors and should be ignored.

Rosenberg challenged Dr. Weaver's use of an average stock price for his constant growth DCF analysis and an end-of-period stock price for his multi-stage DCF growth analysis.[112] On cross examination, Dr. Weaver explained that an average stock price is the correct value to use to calculate the dividend yield for use in the constant growth DCF model as it better matches to an

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[108] Weaver Direct, p. 24.
[109] Rosenberg Direct LG&E pp. 52-53 and KU, pp. 48-50.
[110] *South Central Bell Telephone Company v. Utility Regulatory Commission*, Ky., 637 S.W. 2d 649 (1982)
[111] See, *Stephens v. South Central Bell Tel. Co.*, Ky., 545 S.W.2d 927 (1976); *Bluefield Waterworks & Imp. Co. v. Public Service Commission of W. Va.*, 262 U.S. 679, 43 S.Ct. 675, 67 L. Ed. 1176 (U.S.1923); *F. P. C. v. Hope Natural Gas Co.*, 320 U.S. 591, 51 P.U.R.(NS) 193, 64 S.Ct. 281, 88 L.Ed. 333, U.S., Jan 03, 1944
[112] Rosenberg Rebuttal LG&E, p. 10, line 1.

annual dividend while an end-of-period stock price that the analysts assure is representative is appropriate for use in the multi-stage DCF model because this model assumes that the cash flow occurs at the end of each of the time intervals used in the analysis.[113] Rosenberg's challenge is erroneous.

Rosenberg challenged Dr. Weaver's use of the arithmetic and geometric mean. He is wrong. The arithmetic mean indicates the average value of a distribution and the geometric mean indicates the compound growth rate over a period of time.[114] In his testimony pertaining to the correct return for the electric operations of KU and LG&E, Weaver used the geometric mean five times to show a compound rate of return. This was done in Schedules 32 and 33 to show the historical growth rate from 1992-2003; in Schedule 38 to show the market return on the Value Line forecast; in Schedule 39, note 7, which explains the calculation of the Value Line forecast of the market return; and on Schedule 40, page 4, to calculate the return relatives of all possible annual holding periods from 1993 to 2003. The represented values of the distributions on all of Weaver's Schedules are arithmetic averages, including on the Schedules listed in the preceding sentence.

Rosenberg claims the CAPM model is not a form of a regression equation in rebutting Weaver's critique of Rosenberg's empirical CAPM for its tendency to increase multicollinearity.[115] The Fisher Black article[116] provides an extensive discussion of the zero-beta, two-factor CAPM. Equation 3, a regression model, begins the discussion in the development of the zero-beta model.

[113] Transcript of Evidence, pp. 193-195.
[114] Weaver Direct, p. 28, line 23.
[115] Rosenberg Rebuttal LG&E, p. 25.
[116] See, Attorney General's Cross Examination Exhibit 1, "Capital Market Borrowing with Restrictive Borrowing", *Journal of Business*, 45 (July 1972), 444-455 at 446.,

Rosenberg challenged Weaver's use of 10-year treasury bonds in his CAPM analysis, claiming them to be too short a rate.[117] Forty five point one percent (45.1%) of the outstanding shares of Rosenberg's comparison group of electric utilities are held by institutional investors.[118] Contrary to Rosenberg's contention, because institutional investors continuously make buy and sell decisions as new information becomes available in the market,[119] a ten-year holding period for the electric securities may cause the ten-year bond rate to be a too-long rate rather than a too-short rate. Under the circumstances it is a more appropriate mid-length rate representing neither extreme. The ten-year rate is appropriate.

Rosenberg challenged Dr. Weaver's use of the expected market risk premium using a Value Line estimate of 40% and claimed that figure to lead to understated results. In response to Question 25 of LG&E's requests for information to the Attorney General, page 7 of 9, the Attorney General provided a copy of a Value Line Investment Survey dated February 13, 2004, which shows that the estimated median price appreciation potential of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence to be 40%. Rosenberg was wrong in asserting that the figure used was incorrect or that it caused understated results.

Rosenberg also incorrectly stated that Value Line considers its price appreciation is for three and one-half years rather than for three to five years, with an average of four years, and criticizes the use of a four year average as leading to understated CAPM results.[120] As shown on the Value Line sheet provided in response to LG&E Data Request 25, page 7 of 9, the price appreciation potential is for the period "three to five years hence." Rosenberg's recalculated

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[117] Rosenberg Rebuttal LG&E, p.18.
[118] See, Weaver Schedule 1.
[119] See, Weaver Direct, p. 5, line 1.
[120] Rosenberg Rebuttal LG&E, p. 25.

CAPM using the three and one-half year price appreciation factor, which resulted in an increase of 135 basis points, is wrong.

Rosenberg is also wrong about the nature of the Value Line beta – it is an adjusted beta, and is not adjusted solely for measurement error.[121] If measurement errors were the reason for the adjustment, as Rosenberg contends, the mis-measurements would be expected to be of a random nature. The adjustments would not consistently increase the betas of stocks with a calculated beta that is less than one nor would it consistently decrease the betas of stock with a beta that is greater than one as Value Line's adjustments do. Value Line's adjustments (the betas are computed using regression analysis) increases betas that are less than one and decreases betas that are greater than one.[122] Having begun with betas that are already adjusted by Value Line and then adjusting them again in the empirical CAPM, Rosenberg has obtained results that are artificially high.

Rosenberg contends that in performing his risk premium analysis Dr. Weaver has used a counterintuitive weighting format in which returns for the older periods were substantially greater than those for more recent periods; giving 11 times the weight to 1993-1994 values that was given to the 2003-2004 values.[123] A review of Dr. Weaver's Schedule 40, page 4 0f 4, the Schedule setting forth this calculation, shows the reverse is true. More recent years were more heavily weighted than were earlier years because the number of times that the annual holding period of a given year is included in the average increases the more recent the year. The holding period for 1993 is included in the average only once. The holding period for the year 2003 is included in the average eleven times. Rosenberg's criticism is without foundation.

[121] Rosenberg Rebuttal, p. 26.
[122] Weaver Direct, p. 16, line 9.
[123] Rosenberg Rebuttal LG&E, p 27.

C. The Commission should accept Dr. Weaver's recommended cost of equity of 10.25% if the ESM is discontinued.

Dr. Weaver selected nine companies that were similar to LG&E and KU to obtain data for his data for his analysis. He performed an extensive risk analysis to determine that the chosen companies are as similar as possible to LGE and KU. Then, using data from these companies he performed the Constant Growth DCF analysis, the Multi-stage DCF analysis, the CAPM analysis and the Bond-yield-equity-risk premium analysis. Following that, he performed a careful economic analysis. In consequence of the economic analysis he increased the results he obtained from the use of the Constant Growth and Multi-stage DCF models, that used historical data, in order to make them forward looking and to account for the higher cost of equity that he believes will persist while these rates are in. The CAPM analysis and the Bond-yield-equity-risk premium analysis already used forecasted interest rates reflecting that increase. The net effect was to increase the overall average by 48 basis points.[124] Ultimately, Dr. Weaver recommended a range for the cost of equity of 9.75% to 10.25%.[125]

When this testimony was filed, there was no indication as to whether the ESM would be continued. Subsequently, an agreement concerning the termination of the ESM has been filed with the Commission. Dr. Weaver indicated at the hearing that in the event the ESM were to be discontinued, his recommended cost of equity would be 10.25%. In the event the ESM is discontinued, the Commission should accept this recommendation. If the ESM is not discontinued, the Commission should accept the range of equity recommendation of 9.75% to 10.25%, with its mid-point of 10%.

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[124] Weaver Direct, p. 64.

[125] Weaver Direct, pp. 63-64; TE Vol III, pp. 188-189.

CONCLUSION

Based upon the foregoing, the Commission should adopt the proposals of the Attorney General pertaining to accounting and depreciation and should utilize a return on equity range of 9.75 to 10.25 with a mid-point of 10.0% to establish the revenue requirements of LG&E for its electric operations. This, in combination with Dr. Weaver's recommended capital structure ratios the recommendation of a short term debt cost rate of 1.06%, A/R securitization rate of 1.39%, long term debt rate of 3.77%, and a preferred stock cost rate of 2.51%, this results in an overall rate of return for LG&E's electric operations of 6.46%. In the event that the parties agreement with reference to the termination of the ESM is approved by the Commission, the return on equity should be increased by 25 basis points.

Respectfully submitted,

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Certificate of Service and Notice of Filing

I hereby certify that this the 4th day of June, 2004, I have filed the original and 11 copies of the foregoing Post Hearing Brief of the Attorney General with the Executive Director of the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 and that I have mailed true copies of same postage prepaid to the parties at the following addresses:

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