COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) APPROVAL OF TARIFFS AND RIDERS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; (4) APPROVAL OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	))))))))))	CASE NO. 2020-00174

RESPONSES TO REQUESTS FOR INFORMATION TO THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY, BY AND THROUGH HIS OFFICE OF RATE INTERVENTION, AND KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. FROM PSC STAFF

The Office of the Attorney General, Office of Rate Intervention and Kentucky Industrial Utility Customers provide the following responses to the Data Requests filed by PSC Staff.

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NOTICE AND CERTIFICATION FOR FILING

Undersigned counsel provides notice that the electronic version of the paper has been submitted to the Commission by uploading it using the Commission's E-Filing System on this 2nd day of November, 2020, and further certifies that the electronic version of the paper is a true and accurate copy of each paper filed in paper medium. Pursuant to the Commission's March 16, 2020, and March 24, 2020, Orders in Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus Covid-19*, the paper, in paper medium, will be filed at the Commission's offices within 30 days of the lifting of the state of emergency.

CERTIFICATE OF SERVICE

Undersigned counsel certifies that it has transmitted on this 2nd day of November 2020, via electronic mail messages, these Requests for Information and the accompanying Read1st file for the electronic filing to the parties of record at the electronic mail addresses listed below. The Commission has not excused any party from electronic filing procedures for this case.

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WITNESS/RESPONDENT RESPONSIBLE:
Stephen J. Baron

QUESTION No. 1
PAGE 1 of 1

Refer to the Direct Testimony of Stephen J. Baron (Baron Testimony), page 15, lines 14–20, through page 16, lines 1–10, and Figure 1. Provide the source, workpapers, and data in Excel spreadsheet form with all cells unprotected and accessible used to generate Figure 1.

RESPONSE:

See attached file.

WITNESS/RESPONDENT RESPONSIBLE:
Stephen J. Baron

QUESTION No. 2
PAGE 1 of 1

Refer to the Baron Testimony, page 5, lines 10–14. Provide a list of the alternative methodologies for production cost allocation that Mr. Baron alleges would result in a more accurate cost of service study for Kentucky Power, and provide an explanation why each alternative methodology is more accurate.

RESPONSE:

Mr. Baron's referenced testimony states: "While I believe that alternative methodologies for production cost allocation that focus more extensively on the summer system peak, which drives the need for capacity on the KPCo system, can be considered the 12 CP study filed by the Company is appropriate in this case to assess the reasonableness of class rates, relative to the cost of providing service." (emphasis added). Alternative cost of service studies that can be considered include a 6 CP methodology, as used by AEP East Operating Company Appalachian Power Company in Virginia, a 1 CP methodology and a 5 Highest Summer CP methodology, which is used to allocate capacity responsibility in the AEP East Zone among LSEs. To the extent that these other methodologies focus on the system peaks that drive the need for capacity, they provide a more appropriate allocator for fixed, demand related generation costs.

WITNESS/RESPONDENT RESPONSIBLE:
Stephen J. Baron

QUESTION No. 3
PAGE 1 of 1

Refer to the Baron Testimony, page 22, lines 17–18. Explain and quantify the substantial subsidies that Mr. Baron alleges will continue even if Kentucky Power's proposed Tariff NMS II is accepted as filed.

RESPONSE:

Mr. Baron has not performed any analysis or quantification of these subsidies. Such subsidies would occur as a result of a CG (customer generation) customer's ability to offset the customer's own usage with solar production. To the extent that such customer utilizes the Company's generation, transmission and distribution system at times when such solar generation is not available to offset the customer's usage, the CG customer must rely on KPCo's generation, transmission and distribution systems. If the solar generation reduces the customer's payments under the standard tariff, the resulting net charges paid by the CG customers would likely not be sufficient to cover the costs incurred by the Company to provide the generation, transmission and distribution service. Effectively, during the limited hours the customer must buy power from the utility due to insufficient solar generation, the customer is not likely to pay enough to cover the full fixed costs of the generation, transmission, and distribution systems used to serve that customer. In this event, the CG customer receives a subsidy, regardless of whether the net exported energy is priced at avoided cost. Unlike a traditional industrial customer with cogeneration, for example, a CG solar customer does not pay a standby rate for backup power to supply energy when the customer's own generation is not available.

WITNESS/RESPONDENT RESPONSIBLE:
Stephen J. Baron

QUESTION No. 4
PAGE 1 of 1

Refer to the Baron Testimony, page 15, lines 10–12. Kentucky Power's 12 CP share of American Electric Power Company's (AEP) load service entity (LSE) costs are currently about 5.6 percent of the total AEP LSE amount. Explain whether Kentucky Power's share of AEP LSE costs would be more equitable if the LSE costs were allocated based on Kentucky Power's contribution at the PJM Interconnection (PJM) 1 CP share rather than their 12 CP share.

RESPONSE:

The transmission issue identified in Mr. Baron's testimony is the disparity between the "KPCo + KY State Transco" standalone transmission revenue requirement vs. the current approach of assigning KPCo and each of the other Operating Companies a load responsibility share of the total AEP LSE transmission revenue requirements. A substitution of a 1 CP allocator for the current 12 CP allocator would not address this cost disparity issue.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 5
PAGE 1 of 1

Refer to the Direct Testimony of Richard A. Baudino (Baudino Testimony), page 23, line 14, and page 24, line 7. Explain whether Institutional Brokers' Estimate System (IBES) is the same source as Yahoo! Finance, and if not, whether IBES or Zacks is one of the three sources used for Mr. Baudino's analysis.

RESPONSE:

According to Yahoo! Finance, the analysts estimates are provided by Refinitiv. It did not state whether Refinitiv provided IBES growth rate estimates, although Refinitiv does compile IBES performance data, among other things.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 6
PAGE 1 of 1

Refer to the Baudino Testimony. Provide all exhibits in Excel spreadsheet format with all formulas intact and unprotected and all rows and columns accessible.

RESPONSE:

Please refer to the attached excel spreadsheet Kentucky Power October 2020 ROE.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 7
PAGE 1 of 1

Refer to the Baudino Testimony, page 25, lines 9–10, and Exhibit RAB- 4. Provide the rationale and support for estimating the expected dividend yield by multiplying the current dividend yield by one plus one half the expected growth rate.

RESPONSE:

The purpose of multiplying the current dividend yield by 1 plus 1/2 the expected growth rate is to estimate the dividend yield that will be in effect in the next year for the proxy group. Using the full expected growth rate will overestimate the expected dividend yield for the proxy group unless every utility company in the group raises its current dividend at the beginning of the next calendar quarter and continues that increased dividend throughout the next year. Such an assumption is highly unlikely of being realized. Using 1/2 the expected growth rate assumes that the group as a whole increases the dividend in the middle of next year and recognizes the differences in dividend policy and timing of dividend increases for individual companies in the proxy group.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 8
PAGE 1 of 1

Refer to the Baudino Testimony, page 25, and Exhibit RAB-4.

a. Explain why it is appropriate to use both dividend and earnings growth rates in the DCF calculations rather than solely earnings growth rates.
b. If it is appropriate to include the dividend growth rate in the DCF calculation, explain why it is accorded a 25 percent weight in the calculation.

RESPONSE:

a. and b. It is appropriate to include Value Line's dividend growth forecast given the fact that dividend income is a significant portion of the total return for regulated utility companies. Value Line is an important and influential sources of information for investors, so it is reasonable to include forecasted dividend growth in the DCF calculations. Expected earnings growth is also important to investors and studies have shown investors rely primarily on earnings growth forecasts when formulating their total return expectations. Therefore, earnings growth forecasts should be weighted more heavily in the expected growth portion of the DCF formula. Mr. Baudino's recommended DCF formulation thus weights earnings growth forecasts 75% and dividend growth 25%. In this particular case, dividend growth is at the top of the average and median growth rate ranges for the proxy group, as shown in Exhibit No. ___(RAB-4).

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 9
PAGE 1 of 1

Refer to the Baudino Testimony, page 30, lines 3–4 and Exhibit RAB- 5.

a. Explain the rationale and support for Mr. Baudino's assertion that it is appropriate to use book value growth rates in the calculations.
b. Explain why the reasoning for not using average growth rates in the CAPM analysis does not apply to the DCF analysis.
c. Provide the average growth rates applicable to the earnings and book value figures.

RESPONSE:

a. DCF theory posits that growth in earnings, book value, and dividends are equal in the constant growth form of the model, which is used in Exhibit No. ___(RAB-5). Using the average of both earnings and book value growth assumes that these two forecasts will essentially converge over the long run.

b. Mr. Baudino used both the average and median values for the growth forecasts for the proxy group.

c. The average earnings growth rate was 11.35% and the average book value growth rate was 7.65%.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 10
PAGE 1 of 1

Refer to the Baudino Testimony, page 31, lines 7–12.

a. Explain why the average income return for 20-year Treasury bonds is used in the calculation as opposed to the 30-year Treasury bond.
b. Provide the average income return for 30-year Treasury bonds over the 1926–2019 period.
c. For the purposes of this study, explain why the historical risk premium should not have the growth rate in the P/E ratio subtracted out, since that is, in part, reflective of the risk premium investors expect in order to invest in stocks over government bonds.

RESPONSE:

a. The D&P data uses 20-year Treasury bonds as its source for long-term government bond income returns and total returns. It does not use 30-year Treasury bonds.

b. The data is not available for 30-Year Treasury bonds.

c. Indeed, the growth rate in the P/E ratio is a part of the long-term historical risk premium and if investors expect that the future risk premium will be similar to past history, then one would include the P/E ratio inflation in the historical risk premium estimate. However, in the publication *2019 Cost of Capital: Annual U.S. Guidance and Examples*, Chapter 3: Basic Building Blocks of the Cost of Equity Capital - Risk-free Rate & Equity Risk Premium from the Cost of Capital Navigator, D&P stated that Ibbotson and Chen removed P/E inflation in their study of the forecasted expected risk premium (ERP) in an attempt to estimate the ERP that could have been expected given the underlying economic changes in the aggregate. Their so-called supply side modeling determined that the long-term ERP that could have been expected based on underlying economics was less than the realized ERP.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 11
PAGE 1 of 1

Refer to the Baudino Testimony, page 32, lines 7–11. Provide a detailed explanation of how Duff and Phelps calculated its normalized risk-free rate using its measure of the "real risk free rate" and expected inflation.

RESPONSE:

The methodology used by Duff and Phelps to estimate its normalized risk-free rate is explained in detail in the publication *2019 Cost of Capital: Annual U.S. Guidance and Examples*, Chapter 3: Basic Building Blocks of the Cost of Equity Capital - Risk-free Rate & Equity Risk Premium from the Cost of Capital Navigator.

Duff and Phelps (D&P) reviews and evaluates (i) various "build-up" methods and (ii) simple averaging in estimating a normalized rate. With respect to estimating a real risk-free rate, D&P analyzed academic studies and research and, based on that analysis, selected a real rate estimate range of 0.0% - 2.0%. For expected inflation, D&P evaluated several approaches that included:

- The difference between the yield on a 20-year U.S. government bond and the yield on a 20-year U.S. TIPS (inflation protected securities).
- A "five-year-forward, five-year ahead" inflation rate that is extracted from interest rate swap markets.
- A collection of well-established surveys of long-term inflation estimates.

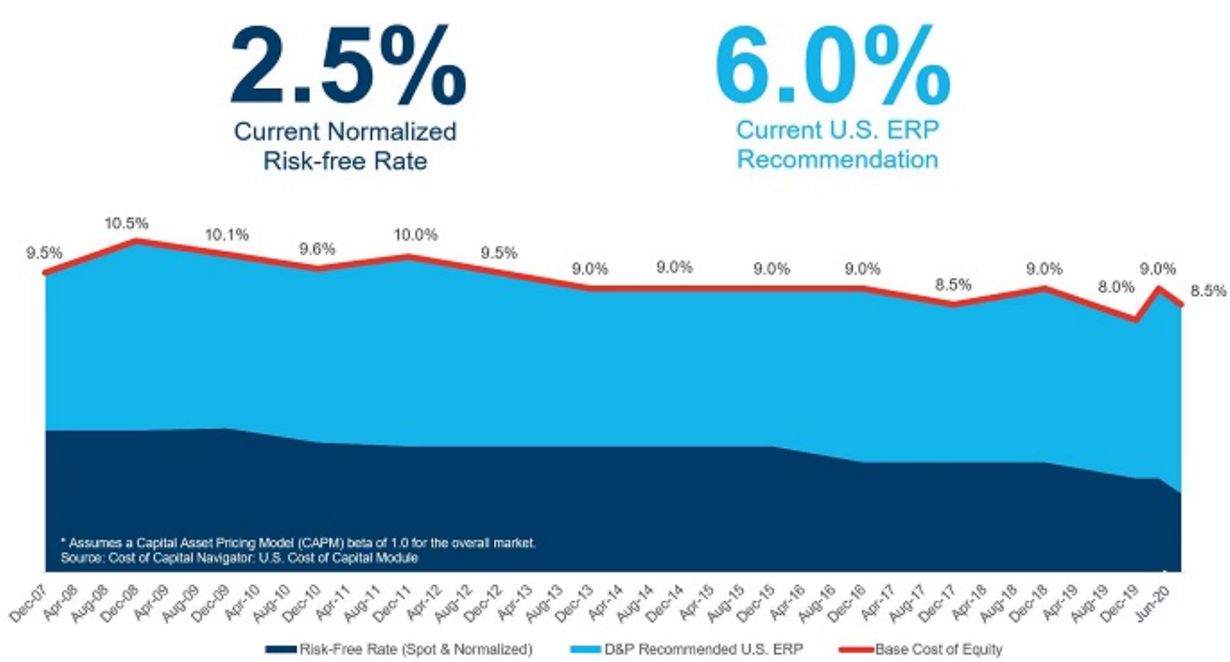
Based on this analysis, D&P settled on a range for the estimated inflation forecast of 2.1% - 2.5%. Adding the real rate range to the inflation forecast range resulted in a range of estimated long-term normalized risk-free of 2.1% - 4.5%. This was based on data ending December 31, 2018. Please note that Chapter 3 has not been updated through 2019 at the time Mr. Baudino prepared this response. However, please refer to the attached data release from D&P dated July 9, 2020 that discusses its selection of 2.5% as its current normalized risk-free rate of return.

Thu, Jul 9, 2020

Duff & Phelps U.S. Normalized Risk-Free Rate Lowered from 3.0% to 2.5%, Effective June 30, 2020


Carla Nunes


James P. Harrington



Duff & Phelps regularly reviews fluctuations in global economic and financial market conditions that warrant a reassessment of the Equity Risk Premium (ERP) and accompanying risk-free rate, both key inputs used to calculate the cost of equity capital in the context of the Capital

Asset Pricing Model (CAPM) and other models used to develop discount rates.

The outbreak of COVID-19 has generated an unprecedented reaction to a pandemic. While global equity markets have recovered substantially from their March 23 lows—benefiting from unparalleled monetary actions by central banks and fiscal stimulus packages by several governments—many of the benchmark equity indices are still lower relative to the levels achieved in mid-February 2020. Equity volatility has decreased from the record highs reached in March, but remains elevated. U.S. consumer confidence and business optimism recovered slightly, but are still significantly lower than pre-coronavirus, while job losses in several industries (and the unemployment rate) continue to be at historical high levels. Economists have further slashed real economic growth projections for 2020, with the global economy now predicted to suffer a worse contraction than during the 2008-2009 Global Financial Crisis.

Based on current financial market and economic conditions, we are reaffirming the Duff & Phelps recommended U.S. ERP at 6.0% to be used in conjunction with a normalized risk-free rate. However, based on declining estimates of real interest rates and lower long-term growth estimates for the U.S. economy, we are lowering the normalized U.S. risk-free rate from 3.0% to 2.5% when developing discount rates as of June 30, 2020 and thereafter, until further guidance is issued. For similar reasons, the normalized risk-free rates for both CAD- and GBP-denominated discount rates are also being lowered from 3.0% to 2.5% when developing discount rates respectively for Canada and the U.K. as of June 30, 2020 and thereafter, until further guidance is issued.

The decision to reaffirm the U.S. ERP recommendation takes into consideration that despite the improvements seen in financial markets, the degree of uncertainty continues to be particularly high when it comes to assessing the ultimate impact of the economic recession on companies' earnings and the shape that the recovery will take. In addition, the upcoming U.S. presidential election in November 2020 may introduce even more uncertainty to the economic environment.

The newly concluded normalized U.S. risk-free rate of 2.5%, together with the re-affirmed recommended U.S. ERP of 6.0% implies a base U.S. cost of equity capital of 8.5% (2.5% + 6.0%).

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 12
PAGE 1 of 1

Refer to the Baudino Testimony, page 34, lines 1–14. To the extent possible, provide a comparison of what the proxy group betas were in the previous five years that supports the contention that the current average beta value is a short-term phenomenon.

RESPONSE:

Mr. Baudino did not assemble the historical betas for the last five years for each company in the proxy group. To do so would require substantial time and effort on Mr. Baudino's part to go through his work papers from cases in which he has testified over the last five years in an attempt to determine whether the Value Line data exists for each company. Mr. Baudino's position is supported by the large and abrupt increase in beta values from the beginning of the year, as shown in his Direct Testimony.

As further support of this position, please refer to Mr. Baudino's Direct Testimony from Kentucky Power Company's last two rate cases, Case No. 2014-00396 and Case No. 2017-00179. These two pieces of testimony are attached to this data request response. Please refer to Exhibit No. ___(RAB-5), page 2 of 2 of his Direct Testimony in Case No. 2014-00396. The comparison group average beta in that case was 0.75. Next, please refer to Exhibit No. ___(RAB-5), page 2 of 2 of Mr. Baudino's Direct Testimony in Case No. 2017-00179. The average beta for the proxy group in that case was 0.67. The two beta values from these prior cases, 0.75 and 0.67, are significantly below the increased beta value for the proxy group in this case, which is 0.87. The companies in these proxy groups from the two prior cases are different from the current case, but the resulting historical betas are consistent with Mr. Baudino's experience in other cases with different proxy groups.

In addition, these are the proxy group betas from Mr. Baudino's cost of equity testimonies filed between January 2019 and April 2020, which will provide additional support for substantially lower electric utility betas prior to the proxy group beta Mr. Baudino calculated in this proceeding:

Docket No. UD-18-07, February 2019, Entergy New Orleans, LLC - 0.60
PUC Docket No. 49494, July 25, 2019, AEP Texas, Inc. - 0.59
Case No. 2019-00271, Duke Energy Kentucky, December 31, 2019 - 0.60
Docket No. E-7, SUB 1214, Duke Energy Carolinas, LLC, February 12, 2020 - 0.56
PUC Docket No. 49831, Southwestern Public Service Company, February 10, 2020 - 0.60
Docket No. E-2, SUB 1219, Duke Energy Progress, LLC, April 13, 2020 - .56

Please refer to Mr. Baudino's attached testimonies for the detailed calculations and support.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 13
PAGE 1 of 2

Refer to the Direct Testimony of Lane Kollen (Kollen Testimony), page 38, lines 4–9. Explain whether Mr. Kollen has additional evidence to support the assertion that the percentage of Edison Electric Institute (EEI) dues identified as influencing legislation is not all inclusive and should be higher, and provide a copy of the additional support.

RESPONSE:

In 1984, the issue of whether electric utility companies should be allowed to recover dues paid to the Edison Electric Institute (EEI) garnered national attention.[1] As a result, the National Association of Regulatory Utility Commissioners started to audit EEI records. Each year, NARUC would publish a breakdown by operating expense category depicting how EEI utilized dues received from its member utilities. It is Mr. Kollen's understanding that NARUC ceased this practice in approximately 2005.

It is Mr. Kollen's understanding that the first published decision arising from a litigated case in which the Kentucky Commission addressed EEI dues was Case No. 10064.[2] The Commission excluded approximately 87% of the $164,390 in dues because the Company had failed to show a direct benefit to ratepayers. I have attached a copy of this decision Exhibit__(LK-PSC-13-1).

The Commission continued this practice of excluding EEI dues in LG&E's next rate case (Case No. 90-158, attached as Exhibit__(LK-PSC-13-2)),[3] and in a 1992 ULH&P rate case (Case No. 91-370, attached as Exhibit__(LK-PSC-13-3)).[4]

The most recent litigated cases in which the Commission addressed the issue of whether EEI dues should be included for ratepayer recovery are Case Nos. 2003-00433[5] and 2003-00434.[6] In those cases, LG&E had sought ratepayer recovery of $195,401[7] in expense for dues the company paid

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[1] See, e.g. the following New York Times article from July 21, 1984: https://www.nytimes.com/1984/07/21/business/utility-group-criticized-on-funds-for-lobbying.html?searchResultPosition=1
[2] In Re: Adjustment of Gas and Electric Rates of Louisville Gas & Electric Co., Final Order dated July 1, 1988, pp. 58-60 (affirmed on rehearing, Order dated Aug. 10, 1988).
[3] Final Order dated Dec. 21, 1990, pp. 35-36, excluding 100% of dues.
[4] Final Order dated May 5, 1992, pp. 47-48, excluding allocated membership dues of $50,993.
[5] In Re: An Adjustment Of The Gas And Electric Rates, Terms, And Conditions Of Louisville Gas And Electric Co., Final Order dated June 30, 2004.
[6] In Re: An Adjustment Of The Electric Rates, Terms, And Conditions Of Kentucky Utilities Co.. Final Order dated June 30, 2004.
[7] Case No. 2003-00433, Final Order dated June 30, 2004, p. 52, fn 112.

QUESTION No. 13
PAGE 2 of 2

to EEI, while KU sought $147,837 for the same purpose.[8] In response to post-hearing data requests of PSC Staff and the Attorney General, item no, 11, the companies provided the NARUC Operating Expense Categories from NARUC's then-most recent audit of EEI. [9] Those expense categories included: (a) legislative advocacy; (b) legislative policy research; (c) regulatory advocacy; (d) regulatory policy research; (e) advertising; (f) marketing; (g) utility operations & engineering; (h) finance, legal, planning and customer service; and (i) public relations. The Commission excluded EEI dues expense related to legislative advocacy, regulatory advocacy, and public relations. The Commission found those three categories accounted for 45.35% of the EEI dues.[10]

Mr. Kollen believes that the Commission could find that an additional adjustment is necessary in order to exclude that portion of EEI dues relating to advertising and marketing, which clearly provide no direct ratepayer benefit. Based on NARUC's most recent Operating Expense Category breakdown as provided in LG&E-KU's responses to post-hearing data requests, advertising accounts for 2.62% of EEI dues, while marketing accounts for 5.84%. Thus the Commission could remove an additional 8.6% of KPCo's EEI dues from ratepayer recovery if it chooses. Mr. Kollen believes such a decision would be well-founded.

In the current case, the EEI invoice KPCo provided in response to AG-KIUC 2-44 identifies only a certain portion of the dues that go toward "influencing legislation." Clearly, the invoice fails to identify what portion of the dues go toward the other two expense categories the Commission has previously identified: regulatory advocacy and public relations. Moreover, KPCo has failed to provide any information establishing that EEI dues provide a direct ratepayer benefit. For that reason, Mr. Kollen believes that his recommended adjustment of 45.35% of all dues is both conservative, and well-founded.

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[8] Case No. 2003-00434, Final Order dated June 30, 2004, p. 45, fn 100.
[9] Accessible at: https://psc.ky.gov/PSCSCF/2003%20cases/2003-00434/KU_Response_051704.pdf

[10] Case No. 2003-00434, Final Order dated June 30, 2004 at 45 (resulting in an exclusion of $67,044); and Case No. 2003-00433, Final Order dated June 30, 2004 at 51-52 (resulting in an exclusion of $88,614). I have attached copies of the 2003-00433 and 2003-00434 Final Orders as Exhibit__(LK-PSC-13-4), and Exhibit__(LK-PSC-13-5), respectively.

EXHIBIT__(LK-PSC-13-1)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 10064

O R D E R

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY) CASE NO. 10064

O R D E R

On November 20, 1987, Louisville Gas and Electric Company ("LG&E") filed an application with the Commission requesting authority to increase its electric and gas rates for service rendered on and after December 20, 1987. The proposed rates would increase annual electric revenues by $37,794,000, an increase of 8.5 percent, and annual gas revenues by $12,073,000, an increase of 7.27 percent. These increases represent an annual increase in total operating revenues of $49,867,000, or 8.16 percent, based on normalized test year sales. This Order grants an increase in annual gas and electric revenues of $21,993,394 or 3.5 percent.

The Commission suspended the proposed rate increases until May 20, 1988 in order to conduct public hearings and investigations into the reasonableness of the proposed rates. A hearing was scheduled for March 22, 1988 for the purpose of cross-examination of the witnesses of LG&E and the intervenors. LG&E was directed to give notice to its consumers of the proposed rates and the scheduled hearing pursuant to 807 KAR 5:011, Section 8. A hearing to receive public comment and testimony was conducted on

March 7, 1988 at the Jefferson County Courthouse in Louisville, Kentucky.

The Commission granted motions to intervene filed by the Utility and Rate Intervention Division of the Office of the Attorney General ("AG"); Jefferson County ("County"); the City of Louisville ("City"); the Department of Defense of the United States ("DOD"); the Utility Ratecutters of Kentucky, Inc. and the Paddlewheel Alliance, referred to as Consumer Advocacy Groups ("CAG"); the Legal Aid Society, Inc. on behalf of Darlene Baker and Jacolyn Petty, residential customers of LG&E and the Fairdale Area Community Ministries, Inc., the West Louisville Community Ministries, Inc., the Sister Visitors Center, and the Inter-religious Coalition for Human Services, Inc., who assist low-income households ("Residential Intervenors"); and the groups of Alcan Aluminum Company, Ashland Oil Inc., Ford Motor Company, Frito-Lay, Inc., General Electric Company, B. F. Goodrich Chemical Group, Interez, Inc., Reynolds Metals Company, and Rohm and Haas Kentucky, Inc., the Kentucky Industrial Utility Customers ("KIUC").

The hearings for the purpose of cross-examination of the witnesses of LG&E and the intervenors were held in the Commission's offices in Frankfort, Kentucky, on March 22-25, 28-29, 1988 and April 4-8, 11-12, 14 and 18, 1988 with all parties of record represented. Briefs were filed May 9, 1988 and the information requested during the hearings has been submitted.

COMMENTARY

LG&E is a privately-owned electric and gas utility which distributes and sells electricity to approximately 311,600 consumers in Jefferson County, and in portions of Bullitt, Hardin, Meade, Oldham, Shelby, Spencer, and Trimble counties and distributes and sells natural gas to approximately 237,000 consumers in Jefferson County and in portions of Barren, Bullitt, Green, Hardin, Hart, Henry, LaRue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Trimble, and Washington counties.

TEST PERIOD

LG&E proposed and the Commission has accepted the 12-month period ending August 31, 1987 as the test period for determining the reasonableness of the proposed rates. In utilizing the historic test period the Commission has given full consideration to appropriate known and measurable changes.

VALUATION

LG&E presented the net original cost, capital, and reproduction cost as the valuation methods in this case. The Commission has given due consideration to these and other elements of value in determining the reasonableness of the proposed rates. As in the past, the Commission has given limited consideration to the proposed reproduction cost.

Net Original Cost

LG&E proposed a total company net original cost rate base of $1,345,749,137. Generally, the proposed rate base was determined in accordance with the Commission's decision in LG&E's last rate case. The net investment rate base has been adjusted to reflect the accepted pro forma adjustments to operation and maintenance expenses in the calculation of the allowance for working capital. As discussed further in the section of this Order relating to the extraordinary property losses, the net investment rate base has been reduced by $19,571,002 to reflect adjustments to the accumulated depreciation reserve and the deferred income tax accounts. The rate base has been increased by $72,780 to recognize 1 year's amortization of the unprotected excess deferred income taxes resulting from the reduction of the corporate tax rate in the Tax Reform Act of 1986 ("Tax Reform Act"). This is achieved by decreasing the deferred tax reserve account to reflect the amortization adjustment described in the section of this Order relating to Excess Deferred Taxes. All other elements of the net original cost rate base have been accepted as proposed by LG&E.

In LG&E's last rate case, the Commission placed LG&E on notice that the Federal Energy Regulatory Commission ("FERC") rulemaking procedure concerning the calculation of working capital would be considered in LG&E's future rate proceedings. FERC has not moved forward on this matter and at this time has not required a lead-lag study for the calculation of cash working capital. In this case, LG&E has determined the allowance for working capital in the same manner as in past rate cases with cash working capital calculated using the 45 day or 1/8 formula.

Thomas J. Prisco, on behalf of the DOD, recommended the use of the balance sheet approach to calculate working capital. His methodology was based upon correspondence from the National Association of Regulatory Utility Commissioners Annual Regulatory

Studies Program and various accounting books. The Commission agrees with the position of the DOD that consumers should not be required to pay rates which include an allowance for excess working capital. However, based on the evidence presented in this proceeding, the Commission is not convinced that the method offered by the DOD is an accurate representation of the balance sheet approach and, therefore, of LG&E's working capital needs. The Commission has, therefore, determined the allowance for working capital in the same manner as proposed by LG&E using the 45 day or 1/8 formula for cash working capital.

The net original cost rate base devoted to electric and gas operations is determined by the Commission to be as follows:

	Gas	Electric	Total
Total Utility Plant	$196,479,603	$1,702,353,408	$1,898,833,011
ADD:			
Materials & Supplies	1,443,870	46,126,080	47,569,950
Gas Stored Underground	22,166,664	-0-	22,166,664
Prepayments	341,417	1,431,429	1,772,846
Cash Working Capital	4,092,780	31,914,475	36,007,255
Subtotal	$ 28,044,731	$ 79,471,984	$ 107,516,715
DEDUCT:			
Reserve for Depreciation	72,817,435	416,540,389	489,357,824
Customer Advances	2,876,070	1,228,267	4,104,337
Accumulated Deferred Taxes	16,988,797	167,531,323	184,520,120
Investment Tax Credit (3%)	508,000	1,421,030	1,929,030
Subtotal	$ 93,190,302	$ 586,721,009	$ 679,911,311
NET ORIGINAL COST RATE BASE	$131,334,032	$1,195,104,383	$1,326,438,415

Capital

LG&E's Controller, M. Lee Fowler, proposed adjustments to LG&E's $1,362,822,255 end-of-test-year capital of $12,250,000. Long-term debt was adjusted to reflect "(1) the retirement of $12,000,000 of 4 7/8 percent First Mortgage Bonds; Series due September 1, 1987; (2) the scheduled redemption of $250,000 of 1975 Pollution Control Bonds due September 1, 1987; and (3) the refinancing of $49,000,000 of the 9.40 percent Pollution Control Bonds."[1] The refinancing of these Pollution Control Bonds did not affect the level of capital but rather the cost of this item. A further adjustment was made to capital to reflect discounts on preferred and common stock.[2]

Dr. Carl G. K. Weaver, an economist and principal with M. S. Gerber & Associates, Inc. and witness for the AG, proposed a capital balance of $1,246,106,059.[3] The difference between Dr. Weaver's proposed capital and Mr. Fowler's was in (1) Dr. Weaver's use of an October 31, 1987 capital balance as reported in LG&E's Financial and Operating Report; and (2) in the adjustments to reflect discounts on preferred stock and common equity.[4]

Lane Kollen, a utility rate and planning consultant with the firm Kennedy and Associates and witness for KIUC, proposed a

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1 Fowler Prepared Testimony, page 14.

2 Ibid., page 17.

3 Weaver Prepared Testimony, Exhibit CGW, Statement 24.

4 Ibid., pages 35-36.

capital balance of $1,289,422,255.[5] Mr. Kollen used LG&E's proposed adjusted capital balance, but made an additional adjustment to common equity to remove "$61.15 million in excess capitalization which is not utilized to support investment in utility property."[6]

Mr. Kollen provided three arguments for reducing common equity by the $61.15 million. First, because preferred stock has remained unchanged and the long-term debt increase of $51 million in pollution control bonds was invested in utility plant, it is the growth in common equity that has been used to finance short-term investments in non-utility plant since test year end of August 31, 1983.[7] Second, "LG&E has only debt and preferred stock directly attributable to utility operations and none whatsoever for non-utility operations."[8] Third, interest and other income from short-term investments is not flowed through to the ratepayers but is received below the line as a direct benefit to the shareholders.[9]

The process proposed by Mr. Kollen of isolating one asset which is not a part of rate base and reducing capital, without a complete evaluation of other assets and liabilities with regard to rate base and capital valuation is inappropriate. In order to

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5 Kollen Prepared Testimony, Exhibit LK-2.

6 Ibid., page 6.

7 Ibid., pages 8-9.

8 Ibid., page 9.

9 Ibid., page 10.

accept Mr. Kollen's adjustment, a complete reconciliation of the assets and liabilities would be necessary to determine appropriate additions and deletions of assets and liabilities to rate base and capital. None of the parties to this proceeding have attempted to make a complete reconciliation of rate base and capital. In the absence of such thorough analysis, the Commission cannot isolate and adjust selective items as proposed by Mr. Kollen. Moreover, the dollar relationship of rate base and capital as provided in this Order is approximately $4.5 million which is reasonable. The isolated adjustment proposed by Mr. Kollen would result in rate base exceeding capital by approximately $56 million. Therefore, Mr. Kollen's adjustment to capital has not been included for rate-making purposes herein.

The adjustments to the end-of-test-year capital proposed by LG&E reflect actual changes in LG&E's end-of-test-year capital which occurred on September 1, 1987 only 1 day after the end of the test period and should be accepted. In addition, the Commission has adjusted LG&E's capital by $19,571,002 to reflect the extraordinary property losses, which are explained in another section of this Order. Concurrent with its adjustment to the rate base to remove the extraordinary losses, a similar adjustment must be made to capital. A company's net investment in utility operations and capital supporting utility operations should be equal, and rate-making steps should be undertaken to attempt to reach this equality. Since the losses do not relate specifically to any specific component of capital, the most equitable approach is to adjust capital on a pro rata basis. Therefore, the Commission is of the opinion that an adjusted capital balance of $1,331,001,253 is reasonable.

In determining capital the test-year-end Job Development Investment Tax Credit ("JDIC") has been allocated to each component of capital on the basis of the ratio of each component to total capital excluding JDIC, as proposed by LG&E. The Commission is of the opinion that this treatment is entirely consistent with the requirement of the Internal Revenue Service that JDIC receive the same overall return allowed on common equity, debt, and preferred stock.

Reproduction Cost

LG&E presented the reproduction cost rate base in Fowler Exhibit 9. Therein, LG&E estimated the value of plant in service, plant held for future use, and construction work in progress ("CWIP") at the end of the test year. The resulting reproduction cost rate base is $2,542,427,739 which includes electric facilities of $2,174,716,164 and gas facilities $367,810,575.

TRIMBLE COUNTY GENERATING STATION ("TRIMBLE COUNTY") - CWIP

In LG&E's last rate case, as well as the Order issued on October 14, 1985 in Case No. 9243, An Investigation and Review of Louisville Gas and Electric Company's Capacity Expansion Study and the Need for Trimble County Unit No. 1, the Commission put LG&E on notice that the historical treatment of CWIP allowed in previous cases should not be taken as an indication that the treatment would continue indefinitely in future cases. In addition, due to the uncertainties surrounding the Trimble County project, the Commission initiated monitoring procedures to keep abreast of the

Trimble County activity. This monitoring contributed to the establishment of Case No. 9934, A Formal Review of the Current Status of Trimble County Unit No. 1.

In the Order in Case No. 9934 entered on July 1, 1988, the Commission found that 25 percent of Trimble County should be disallowed. In this proceeding, the Commission has heard evidence with regard to the rate-making treatment of Trimble County CWIP; however, there has been no specific testimony offered regarding the various options for rate-making treatment of a disallowance of 25 percent of the cost of Trimble County. Furthermore, in Case No. 9934, since the Commission's decision is being issued concurrently with this Order, there has been no specific investigation of the revenue requirement effects of a 25 percent disallowance of Trimble County. Therefore, the Commission has determined that another proceeding will be established to allow a full investigation of this issue. An Order establishing this case will be rendered in the immediate future.

In order to protect the interests of the consumers and assure that the disallowance will be recognized from the date of this Order, the Commission is of the opinion that all revenues associated with additions to CWIP since LG&E's last rate case should be collected subject to refund. The Trimble County CWIP included in rate base in LG&E's last rate case was $268 million and Trimble County CWIP has achieved a level of $382 million at the end of the test period in this case. Applying the overall rate of return allowed in this case to the increase in Trimble County CWIP of $114 million results in an annual provision of $11.4 million to be collected subject to refund. The final amount of disallowances will be determined in the forthcoming Trimble County CWIP case soon to be established and the current ratepayers will realize the benefits of the disallowance when an Order is issued in that case.

In this proceeding, as in LG&E's last two rate cases, the Commission has addressed the issue of continuing the practice of allowing CWIP in LG&E's rate base. While both LG&E and the intervenors have presented arguments supporting and opposing the practice of allowing a return on CWIP, neither side has presented any new arguments or evidence which has not already been considered by this Commission. Consequently, based on the evidence in this case, the Commission is of the opinion that the present regulatory treatment of allowing a cash return on CWIP should continue in light of the decision to complete Trimble County. However, the final amounts utilized for rate-making and revenue requirement determination will be decided in the future proceeding announced in this section of the Order.

RETIREMENTS OF SULFUR DIOXIDE REMOVAL SYSTEMS ("SDRS") AND GAS PLANT

As part of this case, the Commission Staff reviewed LG&E's accounting treatment for the retirement of SDRS and three underground storage fields ("gas fields"). The Staff gave LG&E notice through cross-examination and data requests that the accounting treatment utilized by LG&E ignored the impact these retirements had on LG&E's rate base and the return on that rate base.[10] LG&E

10 Response to the Commission Orders dated December 23, 1987, Item No. 42(a-e); dated January 15, 1988, Item No. 69; and Hearing Transcript, Vol. IV, pages 7, 13-19.

initially advised the Staff in 1986 that it planned to account for the abandoned gas fields as a normal retirement under the Uniform System of Accounts ("USoA"). The accounting treatment was investigated in this case because this was LG&E's first general rate case since these retirements had taken place.

LG&E stated that this accounting treatment was its usual procedure in accounting for abandonments and retirements.[11] In addition, LG&E determined that these entries resulted in a depletion of the depreciation reserve which was now deficient. LG&E proposed to revise upward the depreciation rates for underground gas plant to eliminate the deficiency. The revision was made in 1986, with the depreciation rate for underground gas plant increasing from 3.37 percent to 5.05 percent.[12]

The abandoned gas fields were comprised of several million dollars of undepreciated plant per the company's books. While most of the gas fields were being depreciated over approximately 30 years, significant portions of the gas fields had been in service less than 15 years. As a result of the abandonment, LG&E reported an income tax loss of $3,973,815[13] in 1985. Preliminary figures supplied by LG&E indicated that a book loss, at least as great as the tax loss, existed.[14]

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[11] Response to the Commission Order dated December 23, 1987, Item No. 42(a), page 1 of 2.

[12] Ibid., dated January 15, 1988, Item No. 69(f)(3), page 3 of 3.

[13] 1985 FERC Form No. 1, Annual Report of LG&E, page 261.

[14] Response to the Commission Order dated January 15, 1988, Item No. 69(f)(1), page 2 of 37.

During 1986, Commission Staff obtained information from LG&E which reflected that early retirements of SDRS units were significant and had been accounted for in the same manner as the abandoned gas fields.[15] It was apparent that a depletion of the electric steam production plant depreciation reserve resulted. Since the accounting treatment for these early retirements results in a material impact on revenue requirements, the Commission is of the opinion that this subject is appropriately an issue in this case.

The subject of these early retirements and abandonments has been thoroughly explored through information requests and in cross-examination of LG&E witness, Mr. Fowler. From the information requests, it was determined that for the period 1984 through 1986, LG&E had incurred losses of $21,052,354 due to the early retirements of SDRS units and losses of $6,862,820 due to the abandonment of the gas fields in 1985.[16] If the electric and gas losses are combined, the total losses on these early retirements are $27,915,174. LG&E claimed tax losses on the SDRS units retired between 1984 and 1986 of $3,029,756.[17]

LG&E objected to the questioning of Mr. Fowler on the grounds that the accounting treatments utilized for the SDRS units and gas fields were not relevant to its rate application. LG&E observed that the events did not occur in the test year, and it believed

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15 Ibid., Item No. 69(f)(2 and 3), page 1 of 3.

16 Ibid., Item No. 69(f)(1), page 2 of 37.

17 Ibid., Item No. 69(a), page 1 of 4.

that it was not a proper issue for consideration in this case.[18] The Commission finds that even though the actual retirements and abandonments did not occur in the test year, the subject is highly relevant to this rate case. The impact of retirements losses totaling $27,915,174 exists in the accumulated depreciation reserve and thus is reflected in the net original cost rate base. LG&E has already revised its depreciation rates for underground gas storage plant to offset a portion of the loss and seeks to reflect that change in this case. Moreover, the accounting treatment employed by LG&E does not properly disclose the impact of the early retirements and allows LG&E a full return on the net amount of the losses while the losses are being recovered through depreciation accruals.

LG&E's approach to the retirements transactions, on the surface, is simple and straightforward. While book losses generated by early retirements and abandonments can produce deficiencies in the accumulated depreciation reserve, the increasing of depreciation rates on existing plant will make up the deficiency. Mr. Fowler pointed out that, under LG&E's use of whole life, functional group depreciation, utility plant will often be depreciated beyond the estimated service life and thus can help reduce any existing deficiency.[19]

However, LG&E has failed to recognize that its approach allows the company to reap a double benefit at the ratepayers'

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18 Hearing Transcript, Vol. III, pages 177-178.

19 Ibid., Vol. IV, page 12.

expense. While plant is in service, a company will usually receive a return on the plant and recover the cost of the plant. This is accomplished through the return on the rate base and depreciation expense. LG&E seeks to retain this arrangement on plant that has been retired or abandoned. This approach not only allows for recovery of the inherent deficiency in accumulated depreciation through depreciation expense, but also allows a return on the loss by overstating the rate base. LG&E has maintained that its current treatment benefits its ratepayers by the reserve deficiencies being made up over several years, rather than recovered over a 3- to 5-year period. LG&E contends that 3 to 5 years is a normal amortization period for extraordinary losses, but Mr. Fowler could not cite a publication or pronouncement that supported this claim.[20]

The Commission recognizes that one of the problems which causes this situation is that general plant accounting instructions contained in the USoA does not specifically provide for the possibility of a loss occurring at the time of any retirement. There are three types of property losses provided for in the USoA: losses arising from the disposition of future-use utility plant; losses on the sale, conveyance, exchange or transfer of utility or other property to another; and extraordinary property losses. This last type of loss requires the creation of a deferred debit in Account No. 182, Extraordinary Property Losses.[21] The

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20 Ibid., Vol. III, pages 188-189; Vol. IV, pages 22-23, 51-52.

21 USoA, Electric and Gas Plant Instructions, Item No. 10, parts E and F.

amortization of the account over a set period of years is anticipated in USoA instructions.

In the absence of specific accounting treatment in the USoA, the Commission may utilize other authoritative accounting sources. The Commission generally attempts to minimize discrepancies between generally accepted accounting principles ("GAAP") and its prescribed accounting treatment. Under GAAP applied to non-utility business enterprises, the possibility of a loss occurring at the time of retirement of an asset is specifically recognized. Under those standards, when a major asset is retired from use, the cost and related accumulated depreciation are removed from the accounts, which is similar to the approach outlined in the USoA. However, under GAAP, the charge to accumulated depreciation is limited to the depreciation provided on the asset and since the depreciation expense charged over the estimated useful life of the asset is only an allocation of the cost based on an estimate, a gain or loss will normally be realized on disposal of the asset.

It is conceivable that in GAAP accounting for non-utility enterprises, the practice of group depreciation would exist in which case the entity would account for an asset retired from service in the same manner as prescribed in utility accounting. Thus, it is apparent that another discrepancy in dealing with this issue lies in the eligibility of an asset for group life depreciation. The Commission is of the opinion that the assets here, the gas fields and the SDRS units, are of sufficient value and identifiable enough to warrant individual asset accounting treatment for depreciation and retirement accounting. Thus, the arguments with regard to group depreciation are not valid.

Of the three types of treatment of losses available to LG&E under the USoA, the only applicable treatment is the extraordinary property loss. To be considered extraordinary, the transaction must be of significant effect, not typical or a customary business activity, and would not be expected to recur frequently or be considered as a recurring factor in the evaluation of the ordinary operating process of the business.[22] These restrictions are similar to those prescribed under GAAP. In Accounting Practices Board ("APB") Opinion 30, an extraordinary item is defined as a transaction which is of an unusual nature and has an infrequency of occurrence given the environment in which the business operates.[23] Under the current USoA, the use of extraordinary treatment must be approved by the Commission, upon the request of the company.

Based on the information contained in the record, the Commission finds that the early retirements and abandonments constituted extraordinary property losses, and that LG&E should have requested such treatment. The size of the book losses for the SDRS units and gas fields would be considered significant. LG&E has been an industry leader in SDRS technology, a technology which was new and for which service life history was nonexistent. Mr. Fowler stated at the hearing that the company's experience with SDRS units was

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22 Ibid., Item No. 7.

23 APB Opinion 30, paragraph 20.

unusual.[24] The gas fields were abandoned based on the recommendations of a consultant hired by LG&E.[25] While the USoA requires the company to seek Commission approval for the use of extraordinary treatment, the lack of such action on the part of LG&E causes the initiative to shift to the Commission.

It appears that LG&E has failed to recognize the impact its approach has on accounting and rate-making treatments. The use of revised depreciation rates on existing total utility plant is an example of the accounting impact. It is understandable that depreciation rates need to be revised from time to time due to changes in the actual service life history and technological advances. However, increasing the depreciation rates on existing plant to recover deficiencies created by early retirement or abandonment of major items of plant is not justifiable in this instance. If depreciation rates should be increased to make up deficiencies resulting from extraordinary property losses, once the deficiencies are made up the rates should be revised downward. With regard to the rate-making impact, the accumulated depreciation reserve is understated until the reserve is restored by the increased depreciation resulting from the depreciation rate revision. The understated accumulated depreciation reserve in turn causes the net original cost rate base to be overstated. Thus, if the revenue requirement is based on the return granted on

[24] Hearing Transcript, Vol. III, pages 179-180, 190-191.

[25] Response to KIUC's Second Data Request filed February 1, 1988, Item No. 16.

rate base, the revenue required is inflated due to the overstated rate base.

In addition to the impact of the deficiencies in the accumulated depreciation reserve, there is also the issue of the rate-making treatment of deferred income taxes generated by the retired assets. LG&E was asked to provide the deferred income tax balances related to the SDRS units and the gas fields. For the gas fields, LG&E was able to respond that at the date of abandonment deferred income taxes totaled $3,059,100, and that $162,000 had been flowed back by the test year-end, for a balance of $2,897,100.[26] For the SDRS units, LG&E continually stated that this deferred income tax figure could not be readily determined due to the manner in which its deferred tax accounts were maintained. LG&E has identified the total SDRS deferred income tax balance as $4,910,100 at the date of retirement,[27] $5,146,000 at test year-end,[28] and $5,268,800 at calendar year-end 1987.[29] In addition, LG&E stated these figures included the impact of any flowbacks of these taxes. In calculating the balances, LG&E frequently speaks of "presumed retirement dates," and that in some cases, tax depreciation continues after retirement.[30] These

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26 Supplemental Hearing Data Request, filed May 17, 1988, page 4.

27 Response to the Commission Order dated January 15, 1988, Item No. 69(d)(1).

28 Supplemental Hearing Data Request, filed May 17, 1988, page 2.

29 Ibid., filed May 10, 1988, page 1.

30 Ibid., filed May 10 and 17, 1988, page 1.

retirements have occurred, there is no presumption involved. Also, LG&E has not cited references to the Internal Revenue Code to support its claim that tax depreciation can be taken after the retirement of the depreciated asset. Based on the information supplied by LG&E, the Commission believes the most accurate deferred income tax balance for the SDRS units is $4,910,100, the reported balance at the time of the retirement.

In its brief, LG&E proposed that if the Commission required it to recognize the losses as extraordinary and establish regulatory assets, that the regulatory assets should be amortized over a period of 5 years.[31] However, Mr. Fowler stated that, utilizing a 5-year amortization period, the revenue requirements generated under the extraordinary loss proposal would be higher than those generated using LG&E's original accounting and rate-making treatment of the retirements.[32]

The Commission believes that the approach proposed by LG&E in this situation is not proper. The Commission believes that in the situation of the early retirement of the SDRS units and the abandonment of the gas fields, LG&E should have sought extraordinary property loss treatment for these transactions. LG&E's assumption that early retirements are offset by late retirements may be true for certain assets which qualify for group depreciation, but not in the current situation which demonstrates the basic problems of the assumption with regard to the plant retirements in question.

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31 LG&E Brief, filed May 9, 1988, page 44.

32 Hearing Transcript, Vol. IV, pages 14-15.

The dollar magnitude of these retirement losses should not be made up by LG&E by "over depreciating" current assets, since this would result in excessive recovery under ordinary rate-making practices and is not an appropriate criterion on which to base a change in depreciation rates.

Therefore, the Commission hereby requires the extraordinary property loss treatment for the losses experienced with the early retirement of the SDRS units and the abandonment of the gas fields. As such, the accumulated depreciation reserves for both the electric and gas plants should be credited $21,052,354 and $6,862,820, respectively. The debit should be to Account No. 182, Extraordinary Property Losses, with electric and gas subaccounts maintained. The deferred income tax accounts should be debited $4,910,100 for electric and $2,897,100 for gas. The corresponding credits will be to the appropriate subaccount of Account No. 182. The ratepayers of LG&E have provided the dollars represented in the deferred income tax balances. The netting of the total loss to be amortized recognizes this fact.

In determining a proper amortization period, the Commission has considered the undepreciated balance of the assets retired, the impact on operating expenses, and the ultimate effect on the ratepayers and stockholders. The Commission is of the opinion that an amortization period of 19 years is reasonable for the electric extraordinary property loss and that 18 years is reasonable for the gas extraordinary property loss. This represents an approximation of the number of years of the remaining service lives on the assets retired which LG&E had utilized for book depreciation purposes. Had LG&E's approach proposed in its Brief been utilized, with no change in the depreciation rates, it would have recovered the losses approximately over the same period of time. An annual amortization expense of $849,592 for the electric and $220,318 for the gas has been included for revenue requirement determination herein.

The company's proposal to increase the gas depreciation by $211,035 is unnecessary and the gas depreciation expense has been adjusted to reflect the depreciation expense based on the 3.37 percent depreciation rate in effect before the gas field abandonment. The income tax impacts of these adjustments have been included in the calculation of book income tax expense. The net-original cost rate base has been adjusted by $19,571,002 to reflect the accounting entries to the accumulated depreciation reserve and the deferred income tax accounts. The electric rate base has been reduced by a net amount of $16,142,254 reflecting the $21,052,354 increase to electric accumulated depreciation and reduced by the $4,910,100 reduction to electric deferred income taxes. The gas rate base has been reduced by a net amount of $3,428,748 reflecting the $6,862,820 increase to gas accumulated depreciation and reduced by the $2,897,100 reduction to gas deferred income taxes and the $536,972 reduction to gas depreciation expense due to the depreciation rate adjustment.

MANAGEMENT AUDIT OF LG&E

In August 1986, the Commission's Management Audit of LG&E ("Management Audit") was completed. The audit was performed by Richard Metzler and Associates, Inc. and Scott Consulting Group

("RM&A/Scott") under a statute enacted by the Kentucky General Assembly. According to the Executive Summary, the potential cost avoidance or reduction identified during the audit is probably in excess of $6 million to $7 million in annual recurring and $9 million to $10 million in one-time cost savings.[33] RM&A/Scott developed implementation action plans ("Action Plans") for each of the 146 recommendations and LG&E was directed to provide semi-annual reports to the Commission on the implementation of the recommendations.

This is LG&E's first request for a general increase in rates since the completion of the Management Audit. In prepared testimony, Robert L. Royer, President and Chief Executive Officer of LG&E, and Fred Wright, Senior Vice-President of Operations, noted that LG&E had incurred substantial expenditures to implement the Management Audit recommendations. The Commission demonstrated concern regarding the costs and benefits resulting from the Management Audit through the numerous information requests submitted to LG&E. LG&E was requested to provide a witness at the hearing for cross-examination regarding the Management Audit.

This section will focus on four general areas of the audit identified by the following subsections.

1. Closed Recommendations.
2. Management Information Systems.
3. Work Force - Compensation Recommendations.
4. Open Recommendations.

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33 Management Audit of LG&E, Executive Summary, II-13.

Closed Recommendations

In response to the Commission Order dated January 15, 1988, F. L. Wilkerson, Vice-President of Corporate Planning and Accounting for LG&E, provided information regarding the cost and savings of 45 audit recommendations which have been implemented and closed.[34] The response indicated that the test year included $510,300 to $535,300 in costs associated with these recommendations and that the estimated recurring costs were in the order of $719,500 to $749,500. The estimated savings associated with these recommendations actually quantified in that response was related to only 2 of the 45 closed recommendations and totaled $167,000. During cross-examination, Mr. Wilkerson indicated that it is difficult to quantify the savings for this group of recommendations and that the savings, for the most part, were not measurable.[35] As a result, LG&E was requested to file additional information which would provide a description of the nature of the costs included in the test year, identify the type of savings or benefit and the functional area in which the savings will occur, and indicate whether the benefits will be one-time or recurring in nature.

The Commission has reviewed the information filed relevant to these closed recommendations and finds that the actions taken by LG&E in association with the implementation of these recommendations are in the interests of LG&E's consumers. The Commission is

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34 Response to the Commission Order dated January 15, 1988, Item No. 5.

35 Hearing Transcript, Vol. VIII, pages 194-195.

however, concerned with LG&E's failure to quantify the savings and/or benefits associated with implementation of audit recommendations and particularly with the level of estimated recurring costs. In future rate proceedings, LG&E should be better prepared to support the recurring costs associated with closed recommendations in order for the Commission to be able to better determine their reasonableness in light of the associated savings and/or benefits.

Management Information Systems

In response to Item Nos. 1(a) and (b) of the Commission Order dated December 23, 1987, LG&E provided a discussion of its efforts to develop or enhance its major management information systems. The actual development of most of these systems was begun prior to the Management Audit.[36] However, the Management Audit includes numerous recommendations relating to these systems.

The test year includes operating expenses of approximately $2,476,000 associated with development of these systems. LG&E has estimated that they will incur additional costs of $2,421,000 over the 12-month period ending August 31, 1988.[37] Additionally, LG&E has indicated that the estimated expenditures at the completion of the development of these systems will be $11,711,000 operating and maintenance costs and $2,327,000 capital costs.[38]

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36 Ibid., page 208.

37 Response to the Commission Order dated December 23, 1987, Item No. 1(a).

38 Response to Hearing Information Request, Item No. 3, Response 7.

The Executive Summary of the Management Audit addresses, in general terms, the status of LG&E's business systems and indicates that 3 to 5 years will be required to bring LG&E's computer-based systems up to par with the industry.[39] In response to a request for information made during the hearing, LG&E filed documentation indicating that the systems would be completed beginning in 1988 and continuing through 1991.[40] That response also indicated that the development of some of these systems began as early as 1983. Additional information in the record indicates these systems are still under development and that benefits that may result have not yet been realized. Further, LG&E has indicated that any savings or benefits are not likely to exceed the costs during the immediate future.[41]

LG&E was questioned regarding any cost-benefit analysis performed in connection with these systems and the appropriateness of expensing rather than capitalizing the cost of developing these systems. Cost-benefit analyses of the management information systems, though requested, have not been filed in this proceeding and it is not clear if LG&E has prepared updated cost-benefit analyses as projects progress.[42] Mr. Wilkerson indicated that LG&E felt that it was appropriate to expense the development costs

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39 Management Audit of LG&E, Executive Summary, II-7 to II-8.

40 Response to Hearing Information Request, Item No. 3, Response 7.

41 Response to the Commission Order dated December 23, 1987, Item No. 1(b).

42 Hearing Transcript, Vol. VIII, page 218.

of these systems because LG&E is paying for those costs in today's dollars, because the systems cost money up front, and because unless the company is willing to spend the money no savings will result. Mr. Wilkerson cited a paragraph relating to cost reduction penalties from the Executive Summary as support for LG&E's position.[43] This paragraph however does not address the accounting or rate-making treatment associated with the costs, and includes no prohibition in regard to capitalization of development costs.

The Commission is of the opinion that for the purpose of determining revenue requirements in this proceeding, the test-year operating expenses should be decreased by the $2,475,092 associated with the development costs of the management information systems. The management information systems are being developed to provide benefits to LG&E and its customers over an extended period time. LG&E should begin subsequent to the date of this Order to capitalize and amortize, over a reasonable time period, development costs associated with the management information systems. The costs incurred during and prior to the test year have been expensed during those accounting periods. Therefore, no adjustment to rate base is necessary. The rate-making treatment of costs, capitalized subsequent to the date of this Order, will be considered in future rate proceedings.

<u>Work Force - Compensation Recommendations</u>

The Management Audit contained numerous recommendations relating to the organization structure, work force, and compensation and benefits programs of LG&E. The Executive Summary noted that LG&E could produce annual payroll savings of at least $2.5 million by implementing work force recommendations exclusive of Trimble County considerations.[44] The Management Audit indicated that these savings can be accomplished by:

> . . . increasing organizational productivity through the establishment of work management systems, reducing layers of management, increasing spans of managerial control and revising the personnel skill mix . . .[45]

In addition, specific recommendations instructed LG&E to review the compensation and benefit programs and to annually review health insurance and other benefits programs.

These recommendations are of particular concern to the Commission for several reasons. First, the proposed $5,390,668 increase to test-year operating expenses for labor and labor-related costs was the largest single adjustment proposed by LG&E excluding the adjustments for electric weather normalization and fuel expenses. Second, LG&E was notified in its last rate proceeding, wherein it proposed an increase of $558,000 for Blue Cross-Blue Shield insurance, of the Commission's intended review in the next rate proceeding. In this case, $1,224,561 or approximately 23 percent of the proposed labor and labor-related increase is for health insurance. Third, the level of LG&E's employees has

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43 Ibid., pages 239-240.

44 Management Audit of LG&E, Executive Summary, II-13.

45 Ibid.

been steadily increasing, from 3,646 in 1985[46] to 3,920 on September 6, 1987 and to 3,988 on November 15, 1987.[47]

Moreover, when all of these work-force related recommendations are considered as a whole, they indicate the need for a thorough, comprehensive evaluation of LG&E's organizational structure, and compensation and benefit packages. According to LG&E, the review of the organizational structure, including work force considerations, has begun and LG&E should be able to meet the 3- to 5-year time frame for completion cited in the audit. The Commission is concerned with LG&E's progress in implementing the work-force reduction recommendation of the Management Audit. In August 1986, the Management Audit Report recommended that a reduction in LG&E's work force of 50 to 200 personnel over a 3- to 5-year period exclusive of the Trimble County construction should be accomplished. In response to the recommendation on October 31, 1987 LG&E promulgated its Human Resources Control Program essentially freezing the level of employment on that date and stating a company goal of reducing employment overall. Though LG&E is apparently implementing the planning mechanism called for in the Management Audit, the Commission is concerned with the continued expansion of its work force and the speed at which LG&E is implementing its employment control program. During the period from December 1986 to November 1987, LG&E expanded its work force

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46 Management Audit of LG&E, Chapter XI, Human Resources Management, Exhibit XI-10, Staffing Trends by Employee Group (1975-1985).

47 Response to the Commission Order dated January 15, 1988, Item No. 14.

exclusive of Trimble County from 3,162 to 3,210. The trend in employment is contrary to the intent of the auditors' recommendation and at the very least requires a more detailed explanation than has been provided by LG&E as to the reasons for the work force expansion. The Commission will continue to monitor the non-Trimble County level of employment in the future and will require LG&E to provide a complete explanation for any change in the work force on a semiannual basis. This initial report should be provided to the Management Audit Section starting October 31, 1988.

During the test year, LG&E developed a benefit improvement package for nonunion employees, granted the officer group salary increases greater than would normally have been considered and improved the supplemental benefits authorized for officers.

The improvements for the officer group were intended to address salary compression, and compensation and benefit levels lower than industry averages. LG&E has indicated that the incremental cost of the improvements for this group is between $40,900 and $50,200 for the test year. The benefit improvement package instituted by LG&E included changes in health insurance and group life insurance, and added a thrift-savings plan. This package is of particular concern to the Commission because of the impact on test year costs and the overall level of fringe benefits.

LG&E was notified in Case No. 8924, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated May 16, 1984, of the Commission's intention to review health insurance costs in the next rate proceeding. In addition, the Management Audit contains recommendations directing LG&E to evaluate the compensation and benefit programs and to review health insurance and other benefits programs to ensure cost effectiveness. Mr. Wilkerson, during cross-examination, indicated that the benefit improvement package was not instituted in response to the Management Audit, but for other reasons, among them, maintaining the nonunion benefits comparable to the union employees.[48]

William H. Hancock, Jr., Senior Vice-President of Administration and Secretary of LG&E, presented testimony regarding health insurance and other fringe benefits. He discussed the health insurance cost containment measures taken by LG&E and the newly instituted flexible medical benefit plan. Hancock Exhibit 1 indicates that the rate of increase after cost containment for Blue Cross-Blue Shield insurance was 1.4 percent compared to a rate of 12.8 percent prior to cost containment.[49] Hancock Exhibit 2 reflects an increase in average cost per participant of 29 percent from August 1983 to August 1987 as compared to an industry trend factor of 63 percent over 4 years.[50] These exhibits provide the basis of support regarding LG&E's attempts to control health insurance costs. However, for the 2 years immediately following the institution of the cost containment measures the rate of

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48 Hearing Transcript, Vol. VIII, pages 223-224.

49 Hancock Prepared Testimony, Exhibit 1.

50 Ibid., Exhibit 2.

increase is above 10 percent per year.[51] In addition, the basis of the 63 percent industry trend factor was a letter from an actuarial consultant[52] which neither defines the precise calculation of the factors nor the region considered. The only evidence by which the success of LG&E's cost control efforts can be compared to other utilities or companies in the area that LG&E serves or the state is this ambiguous letter from the actuarial consultant.

Mr. Hancock's testimony indicates that the annual reduction in medical benefits resulting from the flexible benefits program is approximately $500,000.[53] However, the savings are offset by a 3-year cash incentive payment to employees switching to the plan. The test-year operating expenses include $196,408 associated with the payment of the cash incentive for the first year. However, this is only the amount not paid in cash but contributed to the new thrift savings plan. The employees electing to receive actual cash payments received those payments in December 1987 after the end of the test period.

In the Management Audit Action Plan Progress Reports ("Progress Reports") submitted to the Commission in November 1986, LG&E indicated that the company was working with a consultant to evaluate alternate benefit packages and would submit a proposal to

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51 Response to the Commission Order dated December 23, 1987, Item No. 5(d).

52 Response to KIUC First Information Request dated January 14, 1988, Item No. 8, page 2.

53 Hancock Prepared Testimony, page 4.

senior management for consideration.[54] The record in this case contains no evidence that LG&E made any evaluations with regard to any fringe benefits other than health insurance. However, on April 1, 1987, LG&E instituted the new benefit improvement package which will increase LG&E's expenses.

The Commission stated its concern in LG&E's last rate case regarding the level of Blue Cross-Blue Shield insurance. Furthermore, the management auditors recommended that LG&E review, not only health insurance, but the total benefits package. The Commission's and the auditors' concern in this area would require that LG&E provide more adequate support than that which has been included in this proceeding to justify the cost increases to be borne by the ratepayers. Therefore, the Commission is of the opinion that the cost of the change in group life insurance, the cost of the thrift savings plan, and the cost of the cash incentive payments should not be borne by LG&E's ratepayers. The effect of these changes on LG&E's test year costs is specified in the later section of this Order dealing with the proposed labor and labor-related adjustments.

Open Management Audit Recommendations

During cross-examination, Mr. Wilkerson was asked to provide budget projections which reflect the future costs for the projects that were being implemented pursuant to the Management Audit. Mr. Wilkerson responded that the 90 or so open recommendations had not been identified in the budget process and were not readily

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54 Management Audit Action Plans, November 1986, XI-8, page 2.

identifiable.[55] LG&E is hereby placed on notice that in future rate proceedings, the company should be prepared to identify and provide the costs associated with Management Audit recommendations. Due to LG&E's current inability to track these costs and its failure to adequately support, with proper documentation, the claim that post-test year costs will be incurred at the same level as the test year, the Commission finds that the costs associated with the open recommendations should not be included in the determination of revenue requirements.

The test year costs associated with these recommendations were provided in response to Item No. 1 of the Commission's Order dated January 15, 1988. The calculation of the amount disallowed, which is approximately $258,000, is included in a later section of this Order.

Summary

The Commission compliments LG&E on the progress it has made in the implementation of its Action Plans. The Commission continues to have confidence in the benefits that both LG&E and its consumers can derive from proper implementation of its Action Plans. However, the Management Audit, Action Plans, and Progress Reports do not absolve management from its responsibility to continuously monitor and document both the costs and benefits from implementing the recommendations of the management auditors. In future rate proceedings, LG&E should be better prepared to

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55 Hearing Transcript, Vol. IX, pages 76-77.

identify implementation costs, ongoing costs, as well as benefits resulting from implementation of its Action Plan.

REVENUES AND EXPENSES

For the test period, LG&E had actual net operating income of $118,858,318. LG&E originally proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions which resulted in an adjusted net operating income of $111,795,250.[56] Subsequent to its original filing, LG&E proposed several correcting adjustments, which are addressed herein. The Commission is of the opinion that the proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications.

Temperature Normalization - Electric

LG&E proposed an adjustment to electric revenues and expenses for deviations from normal temperatures. The proposed adjustment would reduce operating income by $7,673,763 based on the assumption that the test year included an excess of 402 cooling degree days ("CDD") and a deficiency of 362 heating degree days ("HDD").

An electric temperature normalization adjustment has been proposed in each of LG&E's past three rate applications. In Case No. 8284, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated January 4, 1982, and Case No. 8616, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated March 2, 1983, the adjustment was proposed by LG&E; however, in Case No.

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56 Fowler Prepared Testimony, Exhibit 4.

8924, the adjustment was proposed by an intervenor. The Commission denied the proposed adjustments in each case. In his oral testimony, Patrick Ryan, a Load and Economic Research Analyst with LG&E, summarized the concerns expressed by the Commission in those past cases and stated that the methodology presented in this case addressed those concerns and was the most appropriate way to make this type of adjustment.[57]

This adjustment accounts for 15.4 percent[58] of LG&E's overall requested revenue increase. Additionally, Mr. Ryan has stated that if LG&E's rates are based on excess KWH sales, LG&E's only opportunity to recover its revenue requirement is if the test-year weather pattern occurs in each succeeding year.[59] However, this statement covers only one part of the Commission's concern with the proposed adjustment and the converse of this statement must also be considered. That is, if revenues are based on below normal sales, then consumers will be paying rates that may generate revenue in excess of authorized revenue requirements. Thus, prior to acceptance, it is imperative that the Commission determine if LG&E has accurately reflected the relationship of KWH sales and temperature.

LG&E's methodology begins with the definition of normal weather and the determination of the difference between normal (or expected) weather and actual test year weather. For purposes of

57 Hearing Transcript, Vol. V, pages 9-11.

58 Ryan Prepared Testimony, page 4.

59 Ibid.

calculating the weather adjustment, actual and normal degree day data, the measures of weather used in this analysis were converted from a calendar month basis to that of billing cycles. Because LG&E bills its customers in cycles, it was necessary to calculate both billing cycle days and billing-cycle degree days to match weather data with sales data.

In determining normal billing-cycle degree days, LG&E used the National Oceanic and Atmospheric Administration's ("NOAA") 1951-1980, 30-year average degree day data. By using this average, LG&E has failed to include the degree day data from the most recent 7 years. The Commission is aware from a review of NOAA literature that the NOAA will prepare special HDD or CDD tabulations or other summaries which would include more recent data.[60] However, at the hearing, LG&E indicated that no attempt has been made recently to contact the NOAA to try to get more current degree day normals.[61] The Commission's language in its Order in Case No. 8616 clearly states that current data should be used to define normal degree days:

> A <u>current</u> [emphasis added] 30-year period provides accurate up-to-date information and at the same time is long enough to mitigate any abnormalities in weather conditions, whether they be yearly or cyclical.[62]

60 Environmental Information Summaries, C-14, HDD and CDD Day Data, NOAA, Department of Commerce, USA.

61 Hearing Transcript, Vol. VI, pages 192-193.

62 Case No. 8616, final Order dated March 2, 1983, page 13.

LG&E's use of NOAA's published 1951-80 degree day data[63] as a "current" 30-year average ignores the impact that any recent temperatures may have had in defining normal degree days. The Commission is concerned that it may bias that information which is being considered as the standard for temperature normality.

In Exhibit 2 of his direct testimony, Mr. Ryan constructed 95 percent confidence intervals around the NOAA 1951-1980 30-year means. He asserts that since the annual total degree days and most of the monthly degree days fall outside of the confidence interval, the entire test year must be normalized for abnormal weather. In LG&E's effort to demonstrate that test year weather was abnormal, Mr. Ryan stated:

> Q. Since temperature is a random variable, can't you employ a statistical procedure to determine whether or not actual temperatures were statistically different from the historical average?
>
> A. Yes. This basically would involve the construction of a confidence interval around the mean of the weather variable. If the number of degree days actually incurred during the test period falls outside the confidence interval limits, they can be considered statistically different from the average.[64]

Though LG&E has used a confidence interval as a standard for testing normality, LG&E did not use the confidence interval for temperature adjustment purposes. Mr. Ryan adjusted each month's actual billing cycle temperature-sensitive load to a mean-determined temperature-sensitive load instead of to a

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63 Climatography of the United States No. 81 (By State), Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1951-80, Kentucky.

64 Ryan Prepared Testimony, page 6.

temperature-sensitive load determined by the boundaries of a range of acceptable values constructed around the mean.

The Commission is of the opinion that there is adequate evidence to suggest that a range of temperatures and not a specific mean temperature is a more appropriate measure of normal temperatures. As long as the temperature falls within these bounds then it is inappropriate to adjust sales for temperature. However, if the temperature falls outside those bounds then it is appropriate to adjust sales to the nearest bound.

After determining normal weather and the departure of test year weather from normal, the methodology proposed by LG&E to determine weather-normalized sales involves estimating two components of total energy usage: baseload and temperature-sensitive load. LG&E's actual calculation of the weather normalization adjustment begins by determining the number of customers in each class for each month of the test year, as well as billing cycle days and billing-cycle degree days for each month of the test year. Billing cycle days were defined by Mr. Ryan to be the average number of days in all of LG&E's 21 billing districts for each month during the test year. Billing-cycle degree days were then defined to be the average number of degree days in each billing period for each month.

The Commission is concerned with the calculations of both billing cycle days and billing-cycle degree days. Mr. Ryan indicated on cross-examination that other LG&E personnel were specifically responsible for the calculations[65] and that these calculations assume an average and are not tied to the beginning and ending dates of district billing cycles.[66] This method of determining billing-cycle degree day fails to properly match customer load and their corresponding bills, because each billing cycle has discrete beginning and ending dates with specific degree days and customers associated with that period. Additionally, since no attempt was made to weight the billing-cycle degree days by the percentage of total customers included within each billing district, the results using billing-cycle degree days are not representative of the temperature's affect on electricity usage across billing districts unless each cycle includes approximately the same number of customers per class, an assumption which cannot be confirmed by LG&E.[67] Due to these problems and the lack of supporting evidence, the Commission finds that the method used to convert calendar month days and degree days into billing cycle days and degree days is inaccurate.

The accuracy of the billing cycle calculations is critical because these results are used in the calculation of the final temperature adjustment. Inaccuracies contained in LG&E's billing cycle calculations, therefore, render LG&E's entire electric temperature normalization adjustment unreliable and unacceptable.

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65 Hearing Transcript, Volume V, page 14.

66 Ibid., page 145.

67 Hearing Transcript, Volume V, pages 146-147.

As previously stated, LG&E separated total mWh sales into only two components: baseload and temperature-sensitive load. Residential baseload has been derived from the company's load research data. LG&E determined the daily residential baseload per customer based on the average of the 5 lowest days of daily energy usage from a selected sample of load research customers. For the test year this was determined to be 16.6 KWH per residential customer per day. To determine monthly total residential baseload, the 16.6 was then multiplied by the number of customers in each test year month. This product was then multiplied by monthly-billing cycle days. For the commercial sector, a weighted-average baseload was determined, which includes weekend and weekday usages.

The actual temperature-sensitive load was calculated by simply subtracting the actual estimated baseload per customer from the actual total load per customer. The number of actual billing-cycle degree days was then divided into the actual temperature-sensitive load to obtain the actual energy use per customer, per degree day. Normal temperature-sensitive load was then determined by multiplying the actual energy use per customer, per degree day times the number of customers times the normal number of billing-cycle degree days in that month. This normal temperature-sensitive load was then subtracted from actual temperature-sensitive load to determine the mWh sales adjustment.

Further, LG&E, in adopting its adjustment methodology, has failed to follow previous Commission orders to consider other variables in addition to temperature when normalizing sales. The methodology chosen by LG&E neglects to consider other factors (i.e., personal income, employment, humidity, wind, etc.) that may affect test-year electricity usage. LG&E has recognized that other factors may affect electricity sales but has not incorporated any of these factors in this adjustment.[68] By ignoring these variables LG&E's methodology does not accurately determine the actual relationship of electricity sales to degree days.

In his testimony, Mr. Ryan acknowledges the strong relationship between electricity usage and degree days,[69] as determined by a simple econometric model. Further, Mr. Ryan states that LG&E "is fully aware that variables other than weather affect electricity usage."[70]

The econometric modeling of temperature normalization is widely used by both the electric utility industry and regulatory agencies. During cross-examination, Dr. Carl Weaver, witness for the AG, recommended that to determine temperature-sensitive load, ". . . you should use a regression analysis but include more than one independent variable . . ."[71] Mr. Ryan admitted on cross-examination that to verify that relationships between loads and degree days existed on a class basis, regression analysis would be required.[72] However for the purpose of verifying these

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68 Ibid., Volume V, page 92.

69 Ryan Prepared Testimony, Exhibit 5.

70 Ibid., page 15.

71 Hearing Transcript, Vol. X, page 34.

72 Ibid., Vol. V, page 140.

relationships, Mr. Ryan has ignored those statistical techniques and instead relied upon "eyeballing" the temperature-sensitive load figures.[73] The primary use of an econometric or regression model in weather normalization is to adjust test year sales, which is the intended purpose of a weather normalization adjustment. During cross-examination, Mr. Ryan stated that there was no question in his mind regarding the accuracy of the relationship between degree days and KWH sales because he has been working with weather data and has made the type of computer runs that support the relationship. However, he further stated that the Commission has not seen those computer runs and that other than his assertion that loads per degree day look reasonable, nothing has been filed in the record of this case which verifies the accuracy of that relationship.[74] The Commission cannot allow an adjustment of over $7 million on such a nonspecific basis. In any case, if LG&E desires to propose an electric temperature adjustment in future rate applications, it should develop a methodology that will accurately and appropriately match the random effects of weather to electricity consumption. Further, LG&E should provide adequate support to verify the accuracy and appropriateness of any model presented. The Commission will require that LG&E provide documentation, including adequate statistical analysis, sufficient to support the accuracy of the relationships in the methodology developed and submitted in subsequent rate cases.

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73 Ibid., pages 141-142.

74 Ibid.

Stephen J. Baron of Kennedy and Associates proposed an alternative electric weather normalization adjustment on behalf of KIUC. In discussing the adjustment proposed by LG&E, Mr. Baron criticized several aspects of LG&E's model and concluded that LG&E's methodology was ". . . not precise and cannot be verified as to whether it is correct using actual monthly data."[75] Mr. Baron further stated that he believed that the most appropriate method to develop class weather normalization adjustments was by developing regression models utilizing load research data. No such analysis was presented in this case and Mr. Baron, therefore, determined that using the aggregate system sales and weather data supporting Ryan Exhibit 5 to develop system-wide sensitivity coefficients was the most appropriate way to correct LG&E's proposed adjustment. Mr. Baron then used these system-wide coefficients to adjust LG&E's class-by-class sales, revenue and expense adjustments.

Mr. Baron has recognized several important flaws in LG&E's methodology and attempts to correct these in order to calculate a more representative electric weather normalization adjustment. Mr. Baron's proposed adjustment, however, does not correct the problems presented by LG&E's methodology. By using the system company-wide data supporting Ryan Exhibit 5 (which represents a test year which has been characterized as abnormal) and then interpreting these into class-by-class adjustments, Mr. Baron has

[75] Baron Prepared Testimony, filed February 16, 1988, page 14.

incorporated in his model the same inaccuracies and problems he noted in LG&E's model.

The Commission, therefore, finds that LG&E's proposed electric temperature adjustment should be denied for the following reasons:

1. LG&E's definition of normal degree days is based on 30-year data for the period 1951-1980, which does not include data for the most recent 7 years, including the test year.

2. The critical billing cycle calculations are inaccurate and do not reflect the actual degree days on either an actual or historic basis.

3. LG&E adjusted to a mean rather than to a range determined by a confidence interval.

4. LG&E has recognized only one variable that affects consumption.

5. LG&E did not accurately determine the relationship of KWH sales to degree days. LG&E simply estimated baseload and assigned the difference between total KWH sales and baseload to temperature-sensitive load.

6. LG&E has neither supported all of the assumptions nor supported the accuracy of its model.

The Commission is of the opinion that the electric weather normalization adjustment proposed by KIUC should be denied. The Commission cautions that alternative adjustments that suffer from the same inadequacies as the adjustments they are meant to replace are unacceptable.

Labor and Labor-Related Costs

LG&E proposed adjustments to increase the test-year operating expenses by $5,389,668 for labor and labor-related costs. The actual cost items and the proposed adjustments to combined gas and electric operations are as follows:

	Total
Wages and Salaries	$3,132,927
Pension Costs	34,698
Health Insurance	1,224,561
Dental Insurance	47,280
Group Life Insurance	148,914
Thrift Savings Plan	248,469
FICA Taxes	550,126
Unemployment Taxes:	
State	30,421
Federal	<26,728>
TOTAL	$5,390,668

Excluding the gas supply expense adjustment, the adjustment for labor and labor-related costs represents the largest adjustment to LG&E test-year operating expenses. In this case, as has been previously stated, the labor and labor-related costs are areas of concern for two reasons: the notice in Case No. 8924 that the Commission would analyze health insurance costs in LG&E's next rate case and the recommendations incorporated in the Management Audit regarding fringe benefits and work force considerations.

Wages and Salaries

LG&E proposed to increase wages and salaries by $3,132,927 in order to reflect wage increases granted during and subsequent to the test year. The first part of this adjustment reflects an increase of $784,852 to recognize the increases granted during the test year. The second part represents the increases granted in

October and November 1987, which results in an increase of $2,348,075. Generally, when utilities request adjustments to wages and salaries, a comparison is made between actual test year wages and salaries and a normalized or pro forma expense level. In this and recent proceedings, LG&E has not determined the adjustment to wages and salaries by the methodology described above. Mr. Fowler testified that LG&E did not follow this methodology because LG&E's test-year labor costs include overtime, shift differentials and other items.[76] Mr. Fowler further stated that LG&E was trying to compare wages on a straight-time basis, that overtime was not included in the adjustment and that the adjustment was very conservative.[77]

Mr. Kollen, on behalf of KIUC, agreed with the first part of the wage adjustment but recommended that the second part be denied in that it represents increases granted outside the test year.

LG&E's wages and salaries consist of various components including overtime pay, shift pay, and straight-time labor. Since LG&E has adjusted only the straight-time component, the Commission does agree that the adjustment is conservative. The Commission also recognizes that the second part of the proposed adjustment is based upon increases granted subsequent to the test period. However, the Commission has, in some circumstances, allowed adjustments of this nature for various reasons. Allowing this adjustment will provide a more accurate matching of wage expense to the

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76 Hearing Transcript, Vol. III, page 130.

77 <u>Ibid</u>.

future rates which are intended to recover those wages. Additionally, the Commission notes that in Case No. 8616, which used a test year ended June 30, 1982, the Commission allowed LG&E to pass on wage increases granted in October and November 1982.[78] Therefore, the Commission is of the opinion that the full amount of the proposed adjustment to wages and salaries should be accepted.

Even though LG&E has adjusted only one component of wages and salaries, the Commission is concerned with LG&E's inability to provide the actual test year expense for each component of wages and salaries inasmuch as such information is necessary to accurately determine an adjustment to wages and salaries. During cross-examination, Mr. Fowler indicated that LG&E does not completely maintain the payroll records by employee classes[79] and in response to Commission data requests stated that,

> The automated payroll file by employee category is constantly changing as employees are added, deleted or transferred between categories and the data for prior periods is not retained. Thus, the annualized straight-time salaries of employees by categories can be determined for current employees, but such a calculation cannot be made for prior periods.[80]

LG&E is encouraged to incorporate the ability to determine the separate components of wages and salaries in the Management Information Systems being developed. The Commission, in future LG&E rate cases, will review the adjustments proposed for wages and

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78 Case No. 8616, final Order dated March 2, 1983, page 23.

79 Hearing Transcript, Vol. III, page 131.

80 Response to the Commission Order dated January 15, 1988, Item No. 8.

salaries while considering the actual test year-end levels of each element.

Group Life Insurance

LG&E proposed an adjustment of $148,914 to increase test-year operating expenses as a result of changes in the premium allowance for nonunion employees and to reflect the increased life insurance premiums resulting from the labor increase allowed in this case. In response to Item No. 16(d), page 10 of the Commission's Order dated November 12, 1987, LG&E provided the calculations to normalize the union and nonunion portions of this adjustment. The insurance benefit is equal to 125 percent of annual salary and the rate per $1,000 of insurance is $.59 for both categories of employees. For all employees, LG&E pays 100 percent of the premium on the first $5,000 of insurance. Prior to April 1, 1987, LG&E paid 75 percent of the premium for insurance in excess of the first $5,000 for all employees; however, on that date, LG&E, in accordance with the nonunion employees' benefit improvement package, began paying, for nonunion employees, 100 percent of the premium in excess of the first $5,000.

The adjustment proposed by LG&E reflects the change instituted in April for the nonunion employees; however, for simplicity, the calculation for union employees does not reflect the fact that LG&E pays 100 percent of the first $5,000 of insurance.[81] The Commission is of the opinion that the Group Life Insurance adjustment should be modified as determined in Appendix

[81] Response to the Commission Order dated December 23, 1987, Item No. 21, page 1.

B to this Order and as discussed below. The union employees' portion of the adjustment is calculated in a manner which does reflect that LG&E pays 100 percent of the premium for the first $5,000 of insurance and 75 percent of the amount over the first $5,000. Additionally, as previously discussed in the preceding Management Audit section of this Order, the nonunion employee portion has been calculated in the same manner as the union employees in order to recognize LG&E's benefit level prior to April 1, 1987. These changes result in a reduction of $40,534 to LG&E's proposed $148,914 adjustment. The Commission will, therefore, allow an increase in test-year operating expenses of $108,380 to reflect the increased costs associated with group life insurance.

Unemployment Taxes

LG&E proposed an adjustment to increase the expenses associated with federal and state unemployment taxes by $3,693. In his direct testimony, Mr. Fowler indicated that the adjustment resulted because of a higher wage base subject to these taxes; however, the decrease in the federal unemployment tax rate offset the increased wage rate and resulted in a negative adjustment for federal unemployment taxes.[82] As shown in Item No. 69(d)(1), the proposed adjustment relating to state unemployment taxes increases expenses by $30,421, while the adjustment related to federal unemployment taxes resulted in a decrease of $26,728.[83]

82 Fowler Prepared Testimony, page 10.

83 Response to the Commission Order dated November 12, 1987.

In determining the amount of the adjustment, LG&E multiplied the base wage subject to unemployment tax by the total employees as of September 22, 1987 and multiplied this product by the applicable tax rate. LG&E provided the total number of employees at the end of several payroll periods in response to a Commission Information Request.[84] In that response, LG&E indicated that there were 3,920 employees as of September 6, 1987, which is the payroll period nearest the end of the test period. During cross-examination, Mr. Fowler indicated that the level of employees used in the adjustment was based on the September 22, 1987 payroll period because that was the approximate date the calculation was performed.[85] Additionally, Mr. Fowler stated that this calculation utilized a 0.6 percent federal unemployment tax rate in anticipation of a proposed change in that rate. Ultimately the change was not effected, thereby leaving the tax rate at 0.8 percent.

The Commission is of the opinion that it is more appropriate to use the number of employees in the payroll period nearest the end of the test year and the federal tax rate actually in effect in the calculation of this adjustment. Therefore, the Commission has, in Appendix C, recalculated this adjustment using 3,920 as the base number of employees and 0.8 as the federal unemployment tax rate. This recalculation results in increases to the test-year federal and state unemployment tax expense of $8,914 and

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84 Ibid., dated January 15, 1988, Item No. 14(c).

85 Hearing Transcript, Vol. III, page 136.

$21,573, respectively. The net effect is an increase to test-year operating expense of $30,487.

Thrift Savings Plan

LG&E proposed an adjustment to increase the test-year operating expense by $248,469 to reflect the normalized expense associated with the thrift savings plan instituted April 1, 1987 in the nonunion employee benefit improvement package. As previously discussed in the Management Audit section, the Commission has disallowed the expenses associated with this item. Therefore, the Commission has reduced operating expense by $180,668 which represents the actual test year expense associated with the thrift savings plan.

Health Insurance

LG&E proposed an adjustment of $1,224,561 to increase the test year level of health insurance expense. Testimony regarding this adjustment was presented by Mr. Hancock. Mr. Hancock also addressed the measures taken by LG&E to control medical benefit costs in response to the final Order in Case No. 8924.

As noted previously in the Management Audit section of this Order, the Commission will allow the proposed increase relating to the expense for the actual health insurance plans, but will not allow LG&E to include the expense relating to the cash incentive payments. According to Item No. 16(d), page 8,[86] the actual test year expense for health insurance was $7,781,922. This amount included $196,408 relating to the cash incentive payments. The

[86] Response to the Commission Order, dated November 12, 1987.

remaining $7,585,514 was subtracted from the pro forma operating expense relating to the actual insurance plans of $8,810,075 to arrive at the proposed adjustment of $1,224,561. The Commission, after reflecting the $196,408 decrease associated with the cash incentive payments, has increased the test-year operating expenses by $1,028,153 to recognize the increased health insurance costs.

Adjustment to Annualize Year-End Electric Volumes of Business

John Hart, Vice-President of Rates and Economic Research for LG&E, proposed an adjustment to reflect the increased costs associated with serving the level of customers at the end of the test year. The proposed adjustment, as amended by Mr. Hart, increased test-year operating revenues by $3,531,357 and test-year operating expenses by $1,860,852. The net effect is a proposed increase in test-year operating income of $1,675,005.

To determine the adjustment to operating revenue, the excess of customers served at test year-end over the test-year average customers was multiplied by an average revenue per customer. The average revenue per customer was determined using the actual revenues from sales to ultimate consumers adjusted to reflect the present rates for a full year, the transfers between rate schedules and normal temperatures. The Commission has previously determined that the proposed electric temperature normalization adjustment should be denied. Therefore, the proposed adjustment to electric operating revenues has been increased to $3,627,565 as calculated by the Commission to reflect the disallowance of the adjustment for normal temperature.

To determine the adjustment to operating expenses, Mr. Hart calculated a cost per KWH of electricity and multiplied that cost by the excess of test year-end customers over test-year average customers. As Mr. Hart explained during cross-examination, this is a traditional calculation made by LG&E[87] which has previously been accepted by the Commission. In performing the calculation in this manner, LG&E has treated all operation and maintenance expenses as variable costs, costs that will increase proportionately with each additional KWH sold. LG&E has not provided conclusive evidence that this is an accurate relationship of all operating expenses to KWH sales. As Mr. Hart admitted during cross-examination, customer accounting expenses, customer service and information expenses, and some portion of administrative and general expenses would vary with the number of customers and not with KWH sales.[88] In response to an information request, LG&E stated that an argument could be made for calculating the expense adjustment based on the company's operating ratio.[89] During cross-examination, Mr. Hart indicated that this approach was not used because he was being conservative in his approach and that his approach had been used for a number of years by LG&E.[90]

The Commission is of the opinion that the approach used by LG&E does not provide an accurate determination of the increase in

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87 Hearing Transcript, Vol. I, page 194.

88 Ibid., Vol. VI, pages 194-195.

89 Response to the Commission Order dated January 15, 1988, Item No. 24.

90 Hearing Transcript, Vol. VI, page 200.

the level of expenses associated with serving additional customers and that it would be more appropriate to use an adjusted operating ratio. The Commission has accepted similar methods to adjust expenses to reflect year-end customers for other companies under its jurisdiction. An appropriate ratio of expenses to sales for use in this case should be 39.84 percent. The calculation of this ratio and the expense adjustment is included in Appendix D of this Order. In determining this ratio, actual test year wages and salaries have been subtracted from actual test year operation and maintenance expenses. It is not appropriate to include wages and salaries in this calculation because the amount of those costs to be included in future rates has previously been adjusted and reflects test year-end employees and post-test-year wage rates. Additionally, the amount of sales to other utilities, which is a net amount, has been deducted from total actual electric operating revenues.

The Commission is of the opinion that this method more accurately reflects the relationship of expenses to sales than the approach used by LG&E. Therefore, the Commission finds that the adjustment to LG&E's electric operating and maintenance expenses should be an increase of $1,445,222. The net effect of this adjustment is a decrease to test-year operating expenses of $2,182,343 or $507,338 above the net amount proposed by LG&E. The Commission advises LG&E that this issue will be considered in future rate proceedings.

Provision for Uncollectible Accounts

LG&E proposed an increase of $250,000 to the test year provision for uncollectible accounts based on its analysis of the appropriate total annual provision. The total provision and the increase were allocated between electric and gas based on the percentage of gross revenues from ultimate consumers for the preceding calendar year. While the Commission finds the proposed increase acceptable, it is concerned about LG&E's use of an allocation method based on revenues instead of actual electric or gas uncollectible account charge-off history. The amounts recorded for electric and gas provisions for uncollectible accounts were not based on the history of uncollectible charge-offs because LG&E did not maintain records of charge-offs by department.[91] LG&E should develop and maintain a record of actual uncollectible charge-offs by department and should utilize that information in adjusting the provision for uncollectible accounts in future rate proceedings.

Depreciation Expense

LG&E proposed to increase depreciation expense by $2,408,809 in order to annualize the test year expense. Of the total adjustment, $2,197,774 was for electric and $211,035 was for gas. Included in the gas depreciation calculations was the depreciation expense for gas underground storage property. The depreciation for this portion of the gas plant was computed using a rate of 5.05 percent. As has been discussed in the section of this Order

91 Response to the Commission Order dated December 23, 1987, Item No. 40.

relating to retirements of SDRS and gas plant, LG&E revised its depreciation rates for gas underground storage property in order to recover the losses incurred when it abandoned three underground storage fields.[92] If LG&E had computed annual depreciation expense using a rate of 3.37 percent, which was in use before the abandonment, there would be a reduction of $536,972 in gas plant depreciation.[93] Because the Commission has decided to treat the abandonment loss as extraordinary, the use of the higher depreciation rate is unnecessary. The Commission has reduced the test-year depreciation expense for the gas plant by $325,937 to reflect the rate of 3.37 percent on gas storage plant. The Commission has accepted the electric depreciation adjustment. Therefore, the total increase to depreciation expense allowed herein is $1,871,837.

Advertising Expense

LG&E proposed to remove $267,278 from its test-year advertising expenses, which represented expenditures which were not allowable for rate-making pursuant to 807 KAR 5:016. The prohibited advertising expenses include promotional, political, and institutional advertising. At the hearing, LG&E witness, Mr. Wilkerson, introduced a schedule of promotional advertising expenses which had not been included in LG&E's original

[92] Hearing Transcript, Vol. IV, page 21.

[93] Response to KIUC Second Data Request, filed February 1, 1988, Item No. 16.

adjustment, and indicated these expenses should also be removed.[94] The additional promotional advertising expenses totaled $52,960. The Commission has accepted both of the advertising adjustments proposed by LG&E, and has reduced advertising expenses by a total of $320,238. The $267,278 in reductions to the electric and gas operations are accepted as proposed; in addition, the $52,960 has been allocated, $40,779 to electric and $12,181 to gas, based on LG&E's reported allocation methods for such costs.

Membership Dues

During the test year, LG&E paid membership dues to the Edison Electric Institute ("EEI") of $164,390 and to the Coalition for Environmental Energy Balance ("CEEB") of $5,800. In addition, LG&E paid $20,760 to EEI as its annual assessment for an acid precipitation study. LG&E included these expenditures in adjusted test-year operating costs.

LG&E was asked to enumerate the benefits of EEI membership and provide any cost-benefit analysis performed concerning membership. LG&E was also asked to provide a breakdown of the EEI dues based on EEI activities. In its responses, LG&E indicated it had not and could not perform cost-benefit analysis of its membership.[95] While providing a listing of benefits, the listing was general in nature and did not document any specific benefits

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94 Hearing Transcript, Vol. VIII, pages 185-191 and Wilkerson Exhibit 1.

95 Response to the Commission Order dated December 23, 1987, Item No. 36(d), page 2 of 7.

received by LG&E's ratepayers.[96] LG&E was asked to describe the nature of CEEB and why it was a member. LG&E provided a general description of the activities of CEEB and explained that the CEEB activities were compatible with LG&E's mission.[97] However, LG&E's responses did not indicate any direct benefits to its ratepayers from CEEB membership.

The Commission is aware that the payment of membership dues to organizations such as EEI and CEEB have received differing regulatory treatment across the country in recent years. The Commission takes notice of two recent cases which involved situations similar to the one the Commission faces in this case. In a case before the Missouri Public Service Commission, EEI dues were disallowed in their entirety because there was no way to quantify the benefits accorded ratepayers and shareholders from membership in the association.[98] In a case before the Massachusetts Department of Public Utilities, the assertion that EEI membership provided numerous and substantial benefits to electric ratepayers did not relieve a utility of its duty to prove that the dues represented a reasonable operating expense and the dues were disallowed.[99]

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96 Ibid., Item No. 36(c), pages 1 and 2 of 7.

97 Response to CAG First Data Request, filed February 8, 1988, Item No. 15.

98 Arkansas Power and Light Company, 74 PUR4th 36 (1986), Case Reference ER-85-265.

99 Western Massachusetts Electric Company, 80 PUR4th 479 (1986), Case Reference DPU 85-270.

In this case, LG&E has failed to show that its membership in EEI and CEEB is of direct benefit to its ratepayers. Therefore, the Commission has excluded all EEI and CEEB costs in the amount of $170,190 from allowable operating expenses for rate-making. This issue will be reconsidered in future cases if LG&E can document that the costs of membership dues provide a direct benefit to the ratepayers.

The Commission recognizes the growing concern in this country over the problems of acid rain. Studies, such as the one being performed by EEI, could provide valuable information in the resolution of this problem. The Commission finds that the EEI acid precipitation study could provide future benefits to LG&E and its ratepayers. Therefore, the Commission has included the $20,760 annual assessment as an allowable rate-making expense.

Excess Deferred Taxes - Tax Reform Act of 1986

In Case No. 9781, The Effects of the Federal Tax Reform Act of 1986 on the Rates of Louisville Gas and Electric Company, Order dated June 11, 1987, the Commission explored the issue of excess deferred taxes resulting from the change in tax rates under the Tax Reform Act. The Commission stated that the accelerated amortization of the unprotected excess deferred taxes would be considered in future rate proceedings.[100] In response to a data request LG&E provided the amount of unprotected excess deferred taxes available for accelerated amortization.[101] In addition, LG&E

[100] Case No. 9781, final Order dated June 11, 1987, page 10.

[101] Response to the Commission Order dated December 23, 1987, Item No. 30.

provided a calculation of a deferred tax deficiency arising from an increase in the state corporate tax rate. LG&E took the position that the federal excess deferred taxes should be offset by the state deficiency in accordance with the Commission Order in Case No. 8616.[102] Mr. Kollen, on behalf of KIUC, has recommended that the unprotected excess deferred taxes as of August 31, 1987 be offset by the same proportion of the state tax deficiency and be returned to the ratepayers as a 1-year credit to base rates.[103] At the hearing, LG&E indicated that the original information filed could violate the normalization requirements of the Tax Reform Act and subsequently filed an amended calculation.

The Commission is of the opinion that the unprotected excess deferred taxes of $4,749,500 as of August 31, 1987,[104] the test year-end, should be offset by the full state tax deficiency of $4,385,600 and amortized over 5 years for rate-making purposes. The effect of this decision is an annual reduction in income tax expense in the amount of $72,780. This amount has been allocated to gas and electric operations in proportion to the existing deferred tax reserve after the adjustment for early retirements with $6,703 allocated to gas operations and $66,077 to electric operations. The rate base has been increased by a like amount to recognize the first year's amortization. LG&E should transfer the excess and deficiency to separate accounts in order that they can

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102 Ibid.

103 KIUC Brief, May 9, 1988, pages 30-33.

104 Response to Hearing Data Request, filed May 9, 1988, Excess Deferred Federal Income Taxes as of December 31, 1987.

be readily identified in future rate proceedings. The Commission is of the opinion that this method is in keeping with the position established in Case No. 8616[105] and does not represent a change of Commission practice.

Management Audit Adjustments

LG&E proposed an adjustment to reflect the recovery of the cost of the Management Audit over a 3-year period. The effect of this adjustment is to increase operating expenses by $194,000. The proposed adjustment allocates $44,620 to gas operations and $149,380 to electric operations. Pursuant to KRS 278.255, the agreement between LG&E, RM&A/Scott and the Commission stated that the cost of the audit would be an allowable expense for rate-making purposes. The Commission, therefore, has accepted the adjustment as proposed by LG&E.

The $2,475,092 test-year cost of the management information systems discussed in the Management Audit section of this Order has been allocated by the Commission to gas and electric and operations in the same proportion as the cost of the Management Audit. The adjustments decrease the test-year operating expenses in the gas department by $569,271 and by $1,905,821 in the electric department.

As previously discussed in the Management Audit section, the Commission has disallowed $258,040 associated with the test-year cost of open management audit recommendations. The test-year cost of $1,477,900 of these recommendations was detailed by LG&E in

[105] Case No. 8616, final Order dated March 2, 1983, pages 20-21.

response to a data request.[106] Commission review of this response indicates that $1,166,900 of these costs have been capitalized or included in the disallowed cost of the management information systems. An additional $52,960 was included by Mr. Wilkerson at the hearing as additional disallowed advertising and has been included in that adjustment, as amended. The remaining $258,040 is based on the following recommendations as detailed in the response to a data request and has been allocated to gas and electric operations as indicated below:[107]

Recommendation	Gas	Electric	Total
V-5	$11,969	$ 40,071	$ 52,040
XI-3	3,220	10,780	14,000
XIV-1	-0-	12,000	12,000
XVI-1, 2, 3	53,000	-0-	53,000
XVIII-1, 2, 3, 5	29,210	97,790	127,000
TOTAL	$97,399	$160,641	$258,040

Recommendations XIV-1 and XVI-1, 2, and 3 have been identified as specific to either gas or electric operations. The other recommendations were allocated to gas and electric operations in the same manner as the cost of the Management Audit.

The total effect of these adjustments is to decrease operating expenses by $2,539,132. The decrease in gas operations is $622,050 and in electric operations is $1,917,082.

106 Response to the Commission Order dated January 15, 1988, Item No. 1.

107 Ibid.

Storm Damage Expenses

LG&E has proposed an adjustment to amortize, over a 3-year period, unrepresentative storm damage expenses incurred during July 1987. This proposed adjustment would decrease test year operations and maintenance expenses by $976,896.

Listed below are actual storm damage expenses for the past 5 calendar years as indicated by LG&E:[108]

Year	Amount
1982	$ 442,375
1983	448,465
1984	332,705
1985	1,670,904
1986	722,355

The actual test-year storm damage expenses were $3,189,909, an amount greater than in any 3 of the past 5 calendar years. After the proposed adjustment is reflected, the test year would still include $2,213,013 in storm damage expenses.

Mr. Fowler of LG&E stated at the hearing that over a 2-week period LG&E's service area was hit by a series of very extensive and unusual storms.[109] Mr. Fowler indicated in his prepared testimony that the company considers these expenses to be legitimate, reimbursable costs.[110] However, LG&E recognized that the recovery of costs of this magnitude might overstate the level of expenses during a normal 12-month period and has, therefore,

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108 Response to the Commission Order dated December 23, 1987, Item No. 25(e).

109 Hearing Transcript, Vol. III, page 116.

110 Fowler Prepared Testimony, page 12.

proposed an adjustment to amortize these costs over a 3-year period.[111]

During redirect examination, Mr. Fowler stated:

> If the Commission takes the position that you cannot recover these costs, we can certainly reduce these costs very easily by allowing the customer to stay off five weeks instead of two weeks or one week, by doing the repairs during normal business hours with our regular employees.[112]

Mr. Fowler further stated during recross-examination that he believed that LG&E should make every effort to restore service but should the Commission exclude costs incurred for the benefit of the customer, there is a point beyond which the company would have to consider the extent of its efforts. He further stated that if ". . . the stockholders are going to have to eat the expenses, there would become a point where maybe a day or two delay would not seem unreasonable."[113]

In determining a reasonable level of operating expenses and an appropriate rate of return, the Commission considers both the risks of the shareholders and the appropriate cost of service to be borne by a utility's ratepayers. In the present case, LG&E argues that the expenses were incurred for the benefit of the ratepayers. However, the stockholders were unable to earn a return until service had been restored. Clearly, expeditious restoration of service is of benefit to both ratepayers and stockholders.

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[111] Ibid.

[112] Hearing Transcript, Vol. IV, page 54.

[113] Ibid., pages 145-146.

The random occurrence of severe storm damage cannot be accurately predicted. This can be seen from the historical calendar year experience noted above. LG&E has focused on only 1 month of the test year in determining that the $1,465,344 abnormal expense incurred in July should be amortized. Mr. Fowler indicated during cross-examination that the 1985 storm damage expense of $1,670,904 was abnormal.[114] Yet, he proposed to include $1,724,565 as an on-going or normal level of storm damage expenses in addition to the amortization of the abnormal July expense of $488,448. The Commission is of the opinion that the test year should include only a reasonable level of storm damage expenses. The proposed adjustment does not render the test period expense representative for rate-making purposes, but projects a level of expense that is clearly abnormal in relation to the historical storm damage expense as indicated by LG&E. The Commission has, on past occasions, determined a reasonable level of expenses by utilizing a historical average and reaffirms that policy. In this case, the average of the test year and the 4 previous calendar years results in an allowable average of $1,272,868 and a decrease in test year expenses of $1,917,041. The Commission finds that this does not deny recovery but merely establishes a reasonable level of expense for the period in which rates will be in effect. In addition, LG&E should continue to make every effort to restore service as soon as possible.

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[114] Ibid., Vol. III, pages 121-123.

Interest Synchronization

The Commission has applied the cost rates applicable to the long-term debt and short-term debt components of the capital structure in order to compute an interest adjustment. The debt components utilized in this computation reflect the effects of the JDIC allocation and reductions to capital structure due to the extraordinary property losses discussed in this Order. Using the adjusted capital structure allowed herein, the Commission has computed an interest adjustment of $122,093 which results in a reduction to income taxes of $47,353.

After applying the combined state and federal income tax rate of 38.785 percent to the accepted pro forma adjustments, the Commission finds that combined operating income should be increased by $25,109 to $118,883,427.

The adjusted net operating income is as follows.

	Gas	Electric	Total
Operating Revenues	$52,020,765	$460,363,195	$512,383,960
Operating Expenses	44,532,659	348,967,874	393,500,533
ADJUSTED NET OPERATING INCOME	$ 7,488,106	$111,395,321	$118,883,427

RATE OF RETURN

Capital Structure

Mr. Fowler proposed an adjusted end-of-test-year capital structure containing 46.17 percent debt, 9.40 percent preferred stock, and 44.43 percent which reflect the adjustments discussed in the Capital section of this Order.

Dr. Weaver, witness for the AG, proposed a capital structure containing 46.20 percent debt, 9.47 percent preferred stocks, and 44.33 percent common equity. As stated in the Capital section of this Order, the difference between Dr. Weaver's proposed capital structure and Mr. Fowler's was the result of the date used by Dr. Weaver in determining capital structure and in the adjustments to reflect discounts on preferred stock and common equity.[115]

Mr. Kollen, witness for KIUC, proposed a capital structure containing 48.55 percent debt, 9.89 percent preferred stock and 41.56 percent common equity based on his proposed adjusted capital.

The Commission has determined LG&E's adjusted capital structure for rate-making purposes to be as follows:

	Amount	Percent
Debt	$ 614,484,032	46.17
Preferred Stock	125,170,510	9.40
Common Equity	591,346,711	44.43
	$1,331,001,253	100.00

In determining the capital structure, the Commission has accepted the adjustments to capital proposed by LG&E and has used the capital ratios reflected as of September 1, 1987. As previously stated, the test-year-end JDIC has been allocated to each component of the capital on the basis of the ratio of each component to total capital, excluding JDIC, as proposed by LG&E and in accordance with past Commission treatment of this item. In

115 Weaver Prepared Testimony, pages 35-36.

addition, the total capital has been reduced by $19,571,002 to reflect the extraordinary property losses, which are explained in another section of this Order. The losses have been allocated on the basis of the ratio of each capital component to the total capital.

Cost of Debt

Mr. Fowler proposed a cost of 8.09 percent for preferred stock which was based on the embedded rate as of August 31, 1987.[116] Dr. Weaver recommended an 8.02 percent rate for preferred stock. The difference between Mr. Fowler's and Dr. Weaver's proposed cost of preferred stock was that Dr. Weaver did not reduce the book value of the outstanding preferred stock by the issuing expense.[117] The Commission is of the opinion that issuance costs should be reflected in the cost of preferred stock. Therefore, the Commission is of the opinion that the reduction in book value of the outstanding preferred stock by the issuing expense is proper and that the 8.09 percent rate reflects the true costs of the preferred stock to LG&E.

Mr. Fowler further testified that LG&E's end-of-test year embedded cost of long-term debt was 7.62 percent and reflects adjustments for the retirement of $12,000,000 of First Mortgage Bonds, Series due September 1, 1987, a sinking fund requirement of $250,000 of 1975 Series A pollution control bonds, and the replacement of 1982 Series B (9.40 percent) pollution control

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116 Fowler Prepared Testimony, page 17.

117 Weaver Prepared Testimony, page 36.

bonds with 1987 Series A (6.876 percent) bonds.[118] Dr. Weaver proposed a cost of debt of 7.51 percent which was based upon October 31, 1987 data.[119] The Commission is of the opinion that long-term cost of debt is 7.62 percent based on the end-of-test-year adjusted data.

Cost of Equity

Dr. Charles E. Olson, President of H. Zinder and Associates and witness for LG&E, recommended a return on equity in the range of 13.75 to 14.25 percent.[120] Dr. Olson's recommendation was based on a discounted cash flow ("DCF") analysis of LG&E. In addition, he utilized both a risk premium analysis and a DCF study of nine electric companies as a check on his estimate of LG&E's DCF cost of equity.

In the LG&E DCF analysis, Dr. Olson used (1) a dividend yield of 7.78 percent based on a dividend of $2.66 and a 6-month high/low average stock price of $34.188; and (2) an estimated dividend growth rate of 5.0 to 5.5 percent based on LG&E's 5-year earnings per share growth rate.[121] This resulted in an overall DCF estimate of 12.78 to 13.28 percent. Dr. Olson performed a risk premium analysis as his first check on his LG&E's DCF estimate. The "premium" that investors required over bond yields was estimated at 3.5 percent. This was higher than the 2.6 percent

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118 Fowler Prepared Testimony, Exhibit 5.

119 Weaver Prepared Testimony, page 37.

120 Olson Prepared Testimony, page 30.

121 Ibid., pages 17-22.

premium from Dr. Olson's source of information, a Paine Webber Mitchell Hutchins, Inc. publication titled "Electric Utility Industry - Electric Utility Analyst Survey" (April 19, 1985).[122] The 3.5 percent risk premium was added to LG&E's current bond yield of 10.1 percent resulting in a 13.6 percent required return. Dr. Olson's second check was based on a DCF analysis of nine electric utility companies and resulted in an average return on equity of 12.79 to 13.29 percent.[123] In addition, Dr. Olson increased his estimates by approximately 8.0 percent to allow for flotation costs and market pressure to arrive at his recommended range of 13.75 to 14.25 percent.[124]

Mr. Royer of LG&E recommended that a return on equity in the range of 13.8 to 14.8 percent is necessary to maintain the financial integrity of LG&E and to fund internal growth at 4.0 to 5.0 percent.

Dr. Weaver recommended a cost of equity in the range of 11.5 to 12.5 percent based on a DCF analysis and used the earnings/price ratio approach as a means to gain additional information. He applied the DCF model to LG&E and a group of four comparable companies using 1987 data and 1978-1980 historical data. Dr. Weaver developed his growth rates using the earnings retention ratio times return on equity (b x r) method. Dr. Weaver's results showed a cost of equity of 10.33 percent for the comparable

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122 Ibid., pages 25-26.

123 Ibid., page 28.

124 Ibid., page 29.

companies and 10.20 percent for LG&E in 1987, and a 13.58 percent and 11.58 percent for 1978-1980, respectively. Dr. Weaver's earnings/price ratio approach averaged 13.04 percent and were higher than his 1987 DCF results, but were closer to the 1978-1980 DCF estimates on the return on equity. Dr. Weaver recommended that no allowances be made for flotation costs or market pressure.

Dr. Jay B. Kennedy, a principal in Kennedy and Associates and witness for KIUC, recommended an 11.75 percent return on equity with a range of 11.34 to 12.21 percent. Dr. Kennedy's proposal was based on a DCF analysis on LG&E. He also performed a DCF analysis on a comparison group of five utilities and a risk premium analysis for verification. His ranges on return on equity were from the results of his DCF analysis and showed LG&E with an average 11.34 percent return on equity and the comparison group with an average 12.21 percent return on equity.[125] Dr. Kennedy's risk premium estimate was based on the difference between the comparison group's average bond yield of 10.02 percent for the July 1987 to December 1987 period, and the DCF cost of equity of 12.21 percent for the comparison group. This risk premium of 2.19 percent was then added to LG&E's long-term debt of 9.82 for a risk premium cost of equity of 12.01 percent.[126] Dr. Kennedy made no allowances for flotation costs or market pressure; however, he suggested that any future costs of issuing common stock be

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125 Kennedy Prepared Testimony, page 40.

126 Ibid., page 41.

measured and recovered externally as a cost of providing service, and levelized over a 30-year period at the weighted cost of capital.

Mr. Kinloch stated that LG&E's rate of return should be 12.0 percent assuming that LG&E no longer receives CWIP, but only 11.0 percent if they are allowed to continue receiving CWIP. Mr. Kinloch's recommendation was based on "current trends from around the nation on recent cases."[127]

The Commission has an obligation to allow LG&E an opportunity to earn a rate of return which will allow it to continue to maintain its financial integrity. In making its determination, the Commission finds that Dr. Olson has basically ignored his own data on growth estimates as provided in his testimony and, therefore, rejects his recommendation of a 14.0 percent return on equity in that it is in excess of an investor's required rate of return. In addition, the Commission also finds that Dr. Weaver's use of the b x r method, if earnings have been inadequate in the past, can understate the growth rate component and, thus, the investor's required return in the DCF analysis. The lower growth rate derived from the b x r method results in a lower allowed return which could result in lower earnings and a lower retention ratio and then a still lower growth rate component and so on. A downward trend could develop and thus weaken the financial integrity of LG&E. The Commission further finds that Dr. Kennedy's failure to give proper weight for the current volatile economic conditions

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127 Kinloch Prepared Testimony, page 13.

results in an understatement of the investor's required rate of return.

Therefore, the Commission having considered all of the evidence, including recent volatile economic conditions, is of the opinion that a return on equity in the range of 12.25 to 13.25 percent is fair, just, and reasonable. A return on equity in this range would allow LG&E to attract capital at a reasonable cost to insure continued service and provide for necessary expansion to meet future requirements, and also would result in the lowest possible cost to ratepayers. A return of 12.75 percent will best meet the above objectives.

Rate of Return Summary

Applying rates of 7.62 percent for debt, 8.09 percent for preferred stock, and 12.75 percent for common equity to the capital structure approved herein produces an overall cost of capital of 9.94 percent. The Commission finds this overall cost of capital to be fair, just, and reasonable.

REVENUE REQUIREMENTS

The Commission has determined that LG&E needs additional annual operating income of $13,463,256 to produce a rate of return of 12.75 percent on common equity based on the adjusted historical test year. After the provision for state and federal income taxes, there is an overall revenue deficiency of $21,993,394 which is the amount of additional revenue granted herein. The net operating income necessary to allow LG&E the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $132,346,683. A breakdown between gas and electric operations of the required operating income and the increase in revenue allowed herein is as follows.

	Total	Gas	Electric
Net Operating Income Found Reasonable	$132,346,683	$13,103,981	$119,242,702
Adjusted Net Operating Income	118,883,427	7,488,106	111,395,321
Net Operating Income Deficiency	13,463,256	5,615,875	7,847,381
Additional Revenue Required	21,993,394	9,174,017	12,819,377

The additional revenue granted herein will provide a rate of return on the net-original cost rate base of 9.98 percent and an overall return on total capitalization of 9.94 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $644,797,735. These operating revenues include $469,555,007 in electric revenues and $175,242,728 in gas revenues.

OTHER ISSUES

"Benchmark" Treatment of Operation and Maintenance Expenses

KIUC proposed a reduction of test-year operating and maintenance expenses totaling $25,771,000, which it claimed reflected the excessive expense growth above inflation and sales growth experienced by LG&E. The amount of reduction was determined utilizing a "benchmark" calculation presented by KIUC witness, Mr. Kollen. Mr. Kollen took the pro forma operation and maintenance expenses for the test year in LG&E's last general rate case and multiplied the amounts by an overall growth factor to arrive at a benchmark level of operation and maintenance expenses.[128] These figures were compared to the pro forma operation and maintenance expenses for the current test year, and the difference calculated. Mr. Kollen's analysis was restricted to non-fuel operation and maintenance expenses. In his prepared testimony, Mr. Kollen indicates that the $25,771,000 in operation and maintenance expenses over his benchmark calculation clearly shows that the growth in those expenses is out of control.[129] He advocates that the Commission adopt some form of cost containment, like the benchmark, as an incentive for LG&E.[130]

During the hearing, Mr. Kollen was cross-examined extensively about his benchmark approach. Mr. Kollen frequently referred to the Florida Public Service Commission ("Florida PSC") utilizing a benchmark approach similar to his proposal. While Mr. Kollen testified that the Florida PSC uses a benchmark approach in all general rate proceedings, he could not cite a rule, regulation, practice, or order which required such a filing.[131] While advocating the benchmark as a means of total operation and maintenance expense containment, Mr. Kollen readily accepted the fact that some functional areas of operation and maintenance expenses could continue to increase in exchange for reduction in

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128 Kollen Prepared Testimony, Exhibit LK-5 and Hearing Transcript, Vol. XI, pages 91-92.

129 Kollen Prepared Testimony, page 14.

130 Ibid., page 18.

131 Hearing Transcript, Vol. XI, pages 97-98.

other areas.[132] In computing the overall growth factor, Mr. Kollen used the change in the sales growth in his calculations although his testimony was that the Florida PSC uses the change in the customer growth.[133]

In its brief, KIUC stated that,

> . . . there is substantial evidence [emphasis added] indicating that the requested level of O & M expense is excessive even when given a liberal recognition of inflation and sales growth. In the absence of specific data [emphasis added] provided by the Company, the Commission should determine the reasonable level of recurring operation and maintenance expense using a benchmark methodology similar to that developed and utilized by the Kentucky Commission two cases ago.[134]

The Commission does not understand how there can be "substantial evidence" while at the same time be an "absence of specific data." In the case which KIUC has referenced to support the benchmark approach, the increase to wages and salaries was denied because of an evaluation of existing economic conditions; therefore, the Consumer Price Index was used as a substitute for the percent of wage increase allowed for rate-making purposes.[135] Thus, the example referred to differs significantly from the proposed benchmark as put forth by KIUC.

The benchmark approach to establishing a fair and reasonable level of expenses may be a useful tool in instances where the data is not available to make specific adjustments, or in abbreviated

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[132] Ibid., pages 100-102.

[133] Ibid., page 103.

[134] KIUC Brief, filed May 9, 1988, page 47.

[135] Case No. 8616, final Order dated March 2, 1983, pages 22-23.

filings or annual earnings adjustment cases allowed by some state regulatory bodies where time constraints are present. However, the Commission in its general rate proceedings, applies the standards of known and measurable as well as fair and reasonable in making adjustments to the historical test period. In this case, many adjustments have been made to reduce historical test year expenses where costs were deemed to be excessive, non-recurring, or otherwise inappropriate for rate-making purposes. The Commission believes that this approach is much more accurate and results in a more reasonable level of operating expenses. The case presented by KIUC on this issue is not conclusive. The Commission has decided not to use the benchmark approach proposed by KIUC in this general rate proceeding.

Gas Cost of Service

In accordance with the Commission's Order of May 29, 1987 in Administrative Case No. 297, An Investigation of the Impact of Federal Policy on Natural Gas to Kentucky Consumers and Suppliers, the Company prepared and filed a fully distributed, embedded gas cost of service study. The study's sponsor, Randall Walker, LG&E's Coordinator of Rates and Tariffs, described the methodology in his testimony,

> In order to allocate costs among the classes of service on the basis of cost incurrence and to determine the relative contribution that each class makes to the overall return on net gas rate base, costs were first assigned to functional groups, then classified as to demand, commodity, or customer-related, and finally, allocated to the classes of service.[136]

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136 Walker Prepared Testimony, page 2.

The study shows that the residential class is being subsidized by all other rate classes of gas service.[137] According to this Exhibit, the adjusted return for the test year for residential service is a negative 0.79 percent, for nonresidential service, 11.93 percent, Fort Knox, 16.5 percent, and seasonal off-peak Rate G-6, 66.34 percent. LG&E stated in its brief that "such an imbalance is undesirable and should be improved."[138] As a result, LG&E is proposing rates which will result in a more equitable recovery of costs, thus reducing the differential in class rates of return. The Residential Intervenors contend that the reason for the residential class's negative return is that the study overstates the costs incurred by the residential class.[139] One example of overstated costs offered by the Residential Intervenors involves the method in which the costs of distribution mains are allocated. LG&E uses the zero-intercept methodology to classify the costs of distribution mains as either demand or customer related. "This methodology again disproportionately assigns costs to the residential class based on a theoretical system design which has no basis in reality."[140] Also critical of LG&E's use of the zero-intercept methodology was the DOD whose witness, Suhas P. Patwardhan, conversely charges that "use of the Company method

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137 Ibid., Exhibit 1, page 4.

138 LG&E Brief, May 9, 1988, page 64.

139 Residential Intervenors Brief, May 9, 1988, page 14.

140 Ibid., pages 14-15.

will result in favorable treatment for small usage customers as opposed to large usage customers."[141] Mr. Patwardhan feels that the use of a minimum-system method would result in a more favorable rate of return performance from large users such as Fort Knox.

The Commission is convinced that the zero-intercept method is theoretically sound and less subjective than the minimum system method, in which a minimum size main must be subjectively chosen in order to determine the customer component.

For the purpose of determining cost causation, LG&E separates its customers into four classes of service, Rate G-1-residential, Rate G-1-nonresidential, Fort Knox and Rate G-6-Seasonal Off-Peak service. This particular breakdown of rate classes evokes this criticism by the KIUC:

> Although LG&E has presented a "cost-of-service study," it is not appropriate because it fails to evaluate cost causation with respect to firm industrial sales customers as distinct from firm commercial sales customers and transportation service as distinct from sales service.[142]

KIUC further contends that the Company's study is contrary to the Commission's guidelines set forth in its Order in Administrative Case No. 297. On pages 42-43 of that Order, the following guidelines are stated, "The Commission prefers that the (cost of service) studies be disaggregated to the greatest extent possible."

Pursuant to its criticism of LG&E's gas cost of service study, KIUC, through its witness Kenneth Eisdorfer, presented an

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141 Patwardhan Prepared Testimony, page 7.

142 KIUC Brief, May 9, 1988, page 87.

alternative study. Mr. Eisdorfer's study disaggregates the Non-residential Rate G-1 category, used by LG&E, into Commercial G-1, Industrial G-1 (Sales), and Industrial G-1 (Transportation). Further, he disaggregates LG&E's Rate G-6 into Sales and Transportation classes of service. His study allocates gas stored underground exclusively to sales service. Otherwise, all cost assignment methodologies are identical to LG&E's.[143]

The Commission is of the opinion that KIUC's assertion that the Company did not fully disaggregate the various classes of service is a valid concern. The Commission will require LG&E to specifically address this issue in the gas cost of service study it files in its next rate case.

Except as described above, the Commission finds that the gas cost of service filed by LG&E provides an adequate starting point for rate design and should be used as the guide for the allocation of revenues to the customer classes.

Electric Cost of Service

LG&E filed an embedded time-differentiated cost of study that used a base-intermediate-peak ("BIP") method to allocate production and transmission demand related costs to costing periods and to customer classes. The methodology used by LG&E was essentially the same as has been used in the last two rate cases with the exception that some of the demand allocators were adjusted to account for temperature-sensitive demand. James W. Kasey,

[143] Eisdorfer Prepared Testimony, page 11.

Coordinator of Rate Research for LG&E, sponsored the embedded cost of service study.

There was considerable concern expressed by the Residential Intervenors, County and CAG with the results of the electric cost of service study. Mr. Kinloch indicated his opposition to LG&E's use of the zero-intercept method for allocating distribution system costs between energy and customer related costs. He stated, "The use of a minimum system calculation assumes that all customers are the same, and that each customer contributes equally to the minimum system requirement."[144] He further contended that customers living in older neighborhoods were closer to generation stations with more fully depreciated infrastructure and contribute less to costs of the distribution system. Mr. Kinloch concluded that the minimum distribution grid costs should be allocated based on energy and recovered through a KWH charge.[145]

The Residential Intervenors expressed concern with LG&E's proposal to include weather normalization adjustment in its cost of service study. The Residential Intervenors contend that they are doubly affected by weather normalization because "the company increased the residential contribution to system peak demand over actual test year contribution to reflect a lower than 'normal' demand,"[146] plus "the company's proposed weather normalization reduced the revenues attributed to the residential class by $8.5

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144 Kinloch Prepared Testimony, page 29.

145 Ibid., page 30.

146 Residential Intervenors Brief, page 12.

million."[147] Thus, the residential class rate of return is reduced to 6.25 percent for the adjusted test year which was below the system average of 8.67 percent. Therefore, the Residential Intervenors proposed that the, ". . . company cost of service study should not be used to assign a greater percentage of any increase to the residential than that assigned to the system as a whole."[148]

The Commission in its Order in Case No. 8924 accepted LG&E's proposed cost of service study's methodology. The Commission continues to be of the opinion that LG&E's BIP methodology is appropriate. Furthermore, the Commission will continue to accept the zero-intercept methodology for the allocation of distribution costs between customer and demand components of the cost of service study. This method is theoretically superior to the alternative proposed by the Residential Intervenors.

Though the Commission is of the opinion that LG&E's cost of service methodology is acceptable, the Commission has serious concerns with the class rate of return results. In this case, LG&E's witness testified that, ". . . the summer and winter system peaks used in this analysis were temperature normalized,"[149] and ". . . several of the demand allocation factors were normalized for the effects of temperature . . ."[150] In a previous section of

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[147] Ibid., page 13.

[148] Ibid., page 13.

[149] Kasey Prepared Testimony, Exhibit 1, page 7.

[150] Ibid., page 11.

this Order the Commission rejected the temperature normalization adjustment. The use of temperature normalized allocators and the temperature normalization adjustment of the winter and summer peaks result in improper allocations of costs to various classes, distorting class rate of return. Therefore, the Commission will reject the cost of service study for use as the basis for the allocation of revenues to the classes. Instead, the Commission will allocate the increase in revenue to each rate class in proportion to its overall increase in rates.

RATE DESIGN

Street Lighting

The City expressed concern about the financial impact of the proposed increased cost of the 400-watt mercury vapor street light with a wood pole. The Commission understands the concerns of the City and recognizes that inequities exist in the tariffs for mercury vapor street lights and the high pressure sodium vapor lights because the rates do not currently reflect cost of service. The Commission agrees with the analysis that LG&E prepared to reflect the movement toward cost-based rates in the street lighting structure. As the Commission has reduced the requested revenue increase by LG&E in this case, the Commission has also adjusted the rates of individual units in the street lighting tariff, which reflects a gradual movement to cost-based rates. The Commission advises the City and LG&E that LG&E should again analyze and update its street lighting tariff in its next rate case.

Disconnect and Reconnection Charge/Monthly Customer Charge

Mr. Kinloch, representing the County and the CAG, stated that the low income customers would be adversely affected by the proposed increases in the disconnect and reconnection charge ("fee") and the monthly customer charge ("charge").[151] Mr. Kinloch stated that the fee applies generally to the bills of the customers that are least able to pay the fee; that the fee is a cost of doing business; that all utilities, such as Louisville Water Company in Louisville and Jefferson County, do not charge such a fee; and that new customers are not charged a hookup fee. The Commission has considered the testimony of Mr. Kinloch and recognizes that this type of a fee by its nature will affect customers experiencing financial difficulties. The fee recovers a cost of business created by a minority of customers. Although Louisville Water Company may not exercise its right to charge this fee, that right is still in its rules and regulations. The Commission does not find that disconnect/reconnect service charges upon the customers creating the need for these services to be comparable to the provision of hookup service at no charge to every customer. While the Commission is sensitive to the concerns of those experiencing financial hardship, it recognizes that a fee of this type allocates costs to cost causers and is a fair and reasonable component of an electric utility rate design. The Commission has and will continue to consider the effects of this charge. In this case, the Commission has adjusted the proposed $4

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151 Kinloch Prepared Testimony, page 22.

increase to $2 to reflect the approximate percent of decrease of LG&E's overall requested increase. The fee is to increase from $12 to $14.

Mr. Kinloch recommended that the monthly residential customer charge for electric service be reduced below the current monthly charge of $3.16 to $2.35 and the residential rate design be changed to a flat rate for the winter months and an inverted block rate for the summer months. Similarly, Mr. Kinloch recommended that the proposed monthly customer charge for gas services be reduced from $5.50 to $3.85. The Commission has accepted the cost of service methodologies proposed by LG&E for the Electric and Gas Divisions but has rejected the proposed weather normalization included in the Electric Division's cost of service study. Mr. Kinloch did not propose a complete cost of service analysis for either the Electric or Gas Division, and the proposed inverted block rate for electric is not a cost-based rate. The rate design as proposed by LG&E has been accepted in the past by the Commission.

The Commission is of the opinion that LG&E's proposed residential rate design appropriately reflects its costs and is fair to all parties. Therefore, considering the objectives of cost-based rates and rate continuity, the Commission has relied on LG&E's proposal in determining approved residential rates.

<u>Off-System Sales</u>

George Gerasimou, witness for KIUC, recommended that the Commission investigate the feasibility of flowing total revenue associated with off-system sales through the monthly fuel adjustment clause ("FAC").[152] He did not propose any adjustment to revenues or expenses in this case related to his proposed treatment of off-system sales. FAC revenues and expenses are reviewed in 6-month hearings under the Commission's regulation 807 KAR 5:056. That regulation is under review in Administrative Case No. 309, An Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056. The Commission is of the opinion that any revision to the FAC regulation should have been presented to the Commission for review in that case.

Revenue Increase Allocation

LG&E based its proposed allocation of revenue increase on its cost of service studies. The Commission has previously rejected the proposed electric cost of service analysis for reasons stated elsewhere in this Order; therefore, the Commission will allocate the allowed electric revenue increase in the proportions of the revised normalized class revenue to the total revised normalized revenue, as illustrated below.

	Revised Normalized Revenue	Percent	Allocation of Revenue Increase
Residential	$172,914,195	38.313	$ 4,900,514
General Service	66,230,541	14.675	1,877,040
Large Commercial	89,790,252	19.895	2,544,717
Large Industrial	91,697,158	20.317	2,598,694
Special Contracts	24,078,953	5.335	682,386
Street and Outdoor Lighting	6,611,828	1.465	187,384
Total Sales Customers	$451,322,927	100.000	$12,790,735
Other Electric Revenue	5,412,703		28,642
Total Electric Operating Revenue	$456,735,630		$12,819,377

152 Gerasimou Prepared Testimony, page 6, A16.

The Commission has accepted the gas temperature normalization and the other revenue adjustments as proposed by LG&E in the $166,068,711 total normalized gas operating revenues. The reduction in the allowed Gas Division revenue increase from the proposed revenue increase will be allocated among those rate classes that LG&E proposed revenue increases. LG&E proposed an extremely large percent increase to the monthly customer charge. The Commission is of the opinion that the proposed customer charges should be reduced to maintain rate continuity. Therefore, all of the reduction in proposed gas revenue increase is allocated to the customer charge. The allocation of the revenue increase is as follows.

Rate Class	Normalized Revenue	Allocation of Revenue Increase
Rate G-1		
Total Residential	$ 89,443,656	$ 8,394,853
Total Non Residential	55,672,127	2,085,578
Rate G-6	13,601,930	<1,324,103>
Rate G-7	106,520	<10,953>
Rate G-8		-0-
Fort Knox Contract	5,783,136	-0-
Total Sales and Transportation	$164,607,369	$ 9,145,375
Other Revenues	1,461,342	28,642
Total Gas Operating Revenues	$166,068,711	$ 9,174,017

Economic Development Rate

LG&E, through its witness, Fred Wright, has proposed an Economic Development Rate ("EDR") to be administered as a rider to LG&E's Large Commercial Rate - LC, Large Commercial Time-of-Day

Rate - LC-TOD, Industrial Power Rate - LP, and Industrial Power Time-of-Day Rate - LP-TOD. Mr. Wright described the purpose of this proposed rate in the following statements:

> LG&E strives to broaden the base of customers over which to spread its fixed costs, in order to keep its retail gas and electric rates as low as practicable so as to remain competitive for new business . . . The EDR is designed to stimulate the creation of new jobs and capital investment both by encouraging existing large commercial and industrial companies to remain in the area and to expand, and by making it more attractive for new companies to move into our service area.[153]

The proposed rate offers companies in the above rate classes, who increase their electric load demand by at least 1,000 Kilowatts over the base year load demand, a reduction to the billing demand during the 8 monthly billing periods from October through May in accordance with the following table:

Time Period	Reduction to Billing Demand
First 12 Months	50%
Second 12 Months	40%
Third 12 Months	30%
Fourth 12 Months	20%
Fifth 12 Months	10%
After 60 Months	0%

For purposes of this rider, the base year is defined as the most recent 12-month calendar year period ending before the effective date of this rider.

Mr. Wright further explains that, "Incentive rates are becoming increasingly common in utility rate tariffs in areas against which the Louisville area must compete."[154] In addition, Mr.

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153 Wright Prepared Testimony, page 3.

154 Wright Prepared Testimony, page 5.

Wright testified that "it (EDR) should not contribute unnecessarily to the Company's future capacity requirements but, rather should improve the Company's electric system load and capacity factors by encouraging growth in a customer class that has a higher load factor."[155] Several parties in this proceeding expressed concern with LG&E's proposed EDR. Mr. Kinloch testified that, although he was not opposed to economic development and the creation of jobs, he is concerned about the mechanism by which LG&E has proposed to address these issues -- the EDR. The first point of concern he raised is that "the EDR rate is below cost of service pricing."[156] Secondly, he expressed apprehension about the potential for success of the EDR and concern with the lack of formal evaluation proposed by LG&E. Finally, Mr. Kinloch addresses the effect, he feels, the EDR will have on LG&E's low-income customers. "While there may be some benefit for a younger low-income customer who is unemployed, the EDR rate will provide absolutely no benefit for elderly customers on fixed incomes."[157] Mr. Kinloch likens the EDR to a lifeline rate proposed for industry instead of to the low-income customers. He suggests that the Commission approve the EDR only if LG&E offers a lifeline rate to elderly customers on fixed incomes.

The Residential Intervenors, during the cross examination of Mr. Wright, raised the concern with the manner in which LG&E will

155 Ibid., page 6.

156 Kinloch Prepared Testimony, page 45.

157 Ibid., page 47.

determine the normality of whether base year demand, above which an additional one megawatt will qualify an LC, LC-TOD, LP, or LP-TOD rate customer for the EDR. Specifically, they were concerned with whether there were unusual circumstances in the base year that would cause a customer's demand to be lower than it would normally be.[158] Mr. Wright responded that each qualifying customer must convince LG&E that he has created jobs and capital investment, and that no unusual circumstances exist in the base year. LG&E did not propose, nor does the EDR rider address, the mechanism by which either of these conditions will be satisfied.

Throughout the record in this case, LG&E has maintained a dual purpose in proposing the EDR: creating additional load, and creating new jobs and new capital investment. The Commission believes that the two purposes are complements. However, the Commission also believes that the concern raised by the intervenors, that LG&E has proposed no mechanism in its EDR to determine that both of these purposes are being addressed, is valid.

The Commission also finds merit with the following concerns raised by the intervenors and its Staff regarding the EDR:

1. The possibility that the EDR is priced below cost of service.

2. The lack of any formal evaluation by LG&E of the effects of the EDR if it is implemented.

3. The effect the EDR will have on LG&E's other ratepayers.

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158 Hearing Transcript, Vol. II, page 222.

4. The fact that the EDR rider does not specify how to determine if base year demand is abnormal or how to determine the effect of the EDR on job creation and capital investment.

5. Whether the EDR should be implemented via a tariff or by special contracts.[159]

There has been a substantial increase in the number of economic development/incentive rates filed with the Commission by both electric and gas utilities during the past year. The purpose of these tariffs, according to the utilities, is to increase the amount of energy sold and/or to expand the level of capital investment and employment in the sponsoring utility's service area. Though the rate designs may vary drastically by utility, they typically provide demand discounts for new and expanding industries within the utility's service area for some specified time period, typically 5 years.

At the current time, the Commission has before it, in addition to LG&E's proposed EDR rider, several economic development/incentive rate proposals. Each of the various tariffs and contracts will require a Commission decision for implementation. Because of the potential volume of tariff and contract filings and their impact on the utility and their customers, the Commission is of the opinion that a consistent policy should be developed on tariff filing and reporting requirements.

The Commission finds that the concerns raised by the parties in the instant case, the number of tariffs and contracts presently

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159 Hearing Transcript, Vol. II, pages 251-253 and 255-256.

under consideration, and the potential implications of these proposals necessitate that utilities which offer economic development/incentive rates to existing or potential customers must satisfy the following requirements, prior to Commission approval of the proposed rate:

1. Each utility should be required to provide an affirmative declaration and evidence to demonstrate that it has adequate capacity to meet anticipated load growth each year in which an incentive tariff is in effect.

2. Each utility should be required to demonstrate that all variable costs associated with the transaction during each year that the contract is in effect will be recovered and that the transaction makes some contribution to fixed costs. Furthermore, the customer-specific fixed costs associated with adding an economic development/incentive customer should be recovered either up front or as a part of the minimum bill over the life of the contract.

3. Each utility that offers an economic development rate should be required to document and report any increase in employment and capital investment resulting from the tariff and contract. These reports should be filed on an annual basis with the Commission.

4. Each utility that intends to offer economic incentive rates should be required to file a tariff stating the terms and conditions of its offering. Furthermore, each utility should be required to enter into a contract with each customer which specifies the minimum bill, estimated annual load, and length of

contracting period. No contract should exceed 5 years. All contracts shall be subject to the review and approval of the Commission.

5. Each utility should be required to include a clause in its contract that states that the tariff will be withdrawn when the utility no longer has adequate reserve to meet anticipated load growth.

6. Each utility should be required to demonstrate that rate classes that are not party to the transaction should be no worse off than if the transaction had not occurred. Under special circumstances, the Commission will consider utility proposals for contracts that share risk between utility shareholders and other ratepayers. However, if a utility proposes to charge the general body of ratepayers for the revenue deficiency resulting from the EDR through a risk-sharing mechanism then the utility will be required to demonstrate that these ratepayers should benefit in both the short- and long-run. In addition, at least one-half of the deficiency will be absorbed by the stockholders of the utility and will not be passed on to the general body of ratepayers. The amount of the deficiency will be determined in future rate cases by multiplying at least one-half of the billing units of the EDR contract(s) by the tariffed rate that would have been applied to customer(s) if the EDR contract(s) had not been in effect.

The Commission is of the opinion that these restrictions on economic development/incentive rates will provide a means for protecting other ratepayers while still providing LG&E, other utilities, and industrial development specialists the opportunity to use lower rates to attract industry.

Furthermore, the Commission is of the opinion and finds that the EDR rider proposed by LG&E is partially consistent with Requirement 4 above. However, the rider must be revised to include language making it completely consistent with all of the above requirements. Therefore, LG&E should withdraw the EDR rider in its present form and refile it within 30 days after all revisions have been made.

Cogeneration and Small Power Production Tariffs

Pursuant to the Order in Case No. 8566, Setting Rates and Terms and Conditions of Purchase of Electric Power from Small Power Producers and Cogenerators by Regulated Electric Utilities, LG&E filed tariffs reflecting its proposed avoided energy and capacity costs. Robert Lyon, Manager of System Planning and Budgets, sponsored the avoided cost studies and tariffs. In preparing estimates of avoided energy costs, LG&E used "its more detailed production costing model, PROMOD III, in place of the EBASCO model (MARCOST 80)." Similarly, in preparing estimates of avoided capacity costs, "computer models used in the Company's recent capacity expansion study were used, v12., EGEAS (Electric Generation Expansion Analysis System) and TALARR (Total and Levelized Annual Revenue Requirements)." Both models are widely accepted and used in the electric utility industry.

In preparing its estimate of avoided capacity costs, LG&E used, "[T]wo twenty-year strategic expansion plans . . ." One plan assumed qualifying facilities with 75,000 KW capacity with an availability of 70 percent and no capacity costs while the other plan did not. The use of Qualifying Facility ("QF") capacity by LG&E resulted in both cancellation and deferment of combustion turbine capacity in its 20-year planning cycle. The difference in the present worth of revenue requirements ("PWRR") between the two plans represented the avoided capacity costs of QF capacity since only the fixed costs of plant ownership were considered in the PWRR analysis. Using a levelized annual revenue requirement of $1,910,000 and assuming 70 percent availability and must run QF operational characteristics, Mr. Lyon proposed a capacity purchase payment of 4.15 mills per KWH. Finally, Mr. Lyon indicated that a QF would have to contract for 20 years to qualify for the proposed capacity purchase payment. In addition, LG&E proposed that each QF be required to post a bond to insure that capacity will be offered for the duration of the contract.

In preparing its avoided energy costs, LG&E used essentially the same method as it used in preparing its estimates in Case No. 8566. Using PROMOD III, LG&E estimated its avoided energy costs at 2.04 cents per KWH. Mr. Lyon indicated that LG&E would apply this avoided energy cost to all QF purchases regardless of whether it was under a 20-year contract or not. He further indicated that LG&E would update its estimates of avoided energy costs and its energy purchase rates annually, and avoided capacity costs and capacity purchase rates updates biannually. Finally, Mr. Lyon indicated that the revised rates would apply to all QF purchases.

The Commission is of the opinion and finds that the proposed rates resulting from the avoided costs are consistent with the

Commission's Order in Case No. 8566. Furthermore, the rates reflect LG&E avoided costs and should be adopted. However, the Commission does intend to continue to monitor LG&E bonding requirements to insure that the requirements do not discourage or hinder QF development.

Natural Gas Tariffs

KIUC proposes that LG&E's gas tariffs be revised to reflect the costs incurred by the utility in serving different customers.[160] KIUC states that the cost of service study LG&E has submitted is deficient "because it fails to evaluate cost causation with respect to firm industrial sales customers as distinct from firm commercial sales customers and transportation service as distinct from sales service."[161] KIUC states that the result of LG&E's revenue proposals for transportation customers will be to earn from these classes an excessive rate of return. KIUC's proposed solution is to utilize the cost of service study presented by its witness, Mr. Eisdorfer.

KIUC's conclusions are based upon the differences between its cost of service study and the one submitted by LG&E. The Commission discusses the two studies elsewhere in this Order in the section entitled Gas Cost of Service, wherein the Commission concludes that these issues raised by KIUC are a valid concern. However, the Commission has decided to have LG&E disaggregate the various classes of service more fully in the gas cost of service

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160 KIUC Brief, filed May 9, 1988, page 87.

161 Ibid., page 86.

study it files in its next rate case. Therefore, it would be inappropriate to order any tariff changes the support for which would require a greater disaggregation between classes than that accepted by the Commission in LG&E's cost of service study.

KIUC also proposes that certain changes be made to LG&E's proposed tariff Rate T applicable to gas transportation service. KIUC states that the proposed language ". . . does not conform with Mr. Hart's representation . . . that transportation service provided under Rate T would be firm and that the language should be corrected by substituting the word "converted" for the word "reduction . . ."[162] KIUC also believes that certain language under the "availability" part of this tariff should be changed to conform to certain provisions in the Order issued in Administrative Case No. 297. Specifically, KIUC argues that the language should clearly state: LG&E has the obligation to tell a prospective transportation customer why it cannot transport gas; and the burden of proof is on LG&E to show that capacity does not exist on its system to transport gas.[163]

The Commission is of the opinion that the proposed language in LG&E's gas tariffs is sufficient to allow a prospective gas customer to understand the services offered and their terms and conditions. The Commission also finds that it is unnecessary for LG&E to substitute the word "converted" for the word "reduction" in the Rate T tariff. LG&E's proposed language allows its

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162 Hearing Transcript, Vol. VI, page 93.

163 Ibid., page 94.

transportation customers to receive transportation service under Rate T as long as LG&E's D-1 and D-2 billing demands from its pipeline supplier are reduced in an amount corresponding to the volumes of gas transported. The Commission understands KIUC's point to be that an end-user through its supplier may request a reduction or conversion of some portion of its supply in order to increase the amount of transportation it can utilize. LG&E agrees that an end-user may request either a reduction or conversion.[164] However, in either case, LG&E must receive a reduction in its billing demands which represent the reduced or converted sales volumes. Otherwise, LG&E's non-transportation customers would ultimately pay the billing demands for those sales volumes not purchased by such an end-user.

Regarding the "availability" section of the Rate T tariff, the Commission does not view the current language as relieving LG&E of its burden of proof. LG&E agrees with the points raised by KIUC.[165] However, the Commission is of the opinion that the language should be clarified to provide prospective transportation customers in a clearer understanding of LG&E's responsibilities. Therefore, LG&E should revise the language in the "availability" section of the Rate T tariff to more clearly comply with the Order issued in Administrative Case No. 297.

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164 Hearing Transcript, Vol. VI, pages 78-79.

165 Ibid., pages 85-86.

Effective Date of New Rates

LG&E's proposed rates were filed with an effective date of December 20, 1987. Pursuant to KRS 278.190(2), the Commission suspended the operation of the proposed schedules for a period of 5 months, until May 20, 1988. On May 19, 1988, LG&E filed a motion stating that if the Commission has not ruled on its rate application by May 20, 1988, LG&E would forego its right to place the proposed rates in effect subject to refund provided that the new rates when authorized will be made effective on May 20, 1988. None of the intervenors objected to this motion and the Commission granted it by Order issued May 20, 1988.

In accordance with that Order, the rates authorized herein are being made effective for service rendered on and after May 20, 1988. With respect to a surcharge to permit LG&E to recover the new rates from May 20, 1988 through the effective date of this Order, LG&E's motion proposed that the surcharge be applied to billings spread over an extended period of time not to exceed December 31, 1988. On June 20, 1988, the Commission received a letter from LG&E proposing that the surcharge be applied only to billings for one month. The Residential Intervenors notified the Commission on June 28, 1988 that it objected to LG&E's proposed modification. The Commission is of the opinion that LG&E should file a surcharge plan within 30 days from the date of this Order. All parties will then be afforded 15 days to file comments on the plan.

SUMMARY

The Commission, after consideration of the evidence of record and being advised, is of the opinion and finds that:

1. The rates in Appendix A are the fair, just, and reasonable rates for LG&E and will produce gross annual revenues based on adjusted test year sales of approximately $644,776,975.

2. The rate of return granted herein is fair, just, and reasonable and will provide for the financial obligations of LG&E with a reasonable amount remaining for equity growth.

3. The rates proposed by LG&E would produce revenue in excess of that found reasonable herein and should be denied upon application of KRS 278.030.

4. The proposed EDR tariff rider should be withdrawn and resubmitted for review when the revisions discussed herein have been made.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix A be and they hereby are approved for service rendered by LG&E on and after May 20, 1988.

2. The rates proposed by LG&E be and they hereby are denied.

3. The proposed EDR tariff rider shall be resubmitted when LG&E has made necessary revisions.

4. Within 30 days from the date of this Order, LG&E shall file with the Commission its revised tariff sheets setting out the rates approved herein.

5. LG&E shall file a surcharge plan within 30 days of the date of this Order and intervenors shall have until 15 days thereafter to file comments.

Done at Frankfort, Kentucky, this 1st day of July, 1988.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988.

The following rates and charges are prescribed for the customers in the area served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE

RESIDENTIAL RATE
(RATE SCHEDULE R)

RATE:

Customer Charge: $3.25 per meter per month.

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

First 600 kilowatt-hours per month	6.023¢ per Kwh
Additional kilowatt-hours per month	4.717¢ per Kwh

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month	6.593¢ per Kwh

WATER HEATING RATE
(RATE SCHEDULE WH)

RATE: 4.761¢ per kilowatt-hour.

Minimum Bill $2.05 per month per heater

GENERAL SERVICE RATE*
(RATE SCHEDULE GS)

RATE:

Customer Charge:

$3.85 per meter per month for single-phase service
$7.70 per meter per month for three-phase service

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

All kilowatt-hours per month 6.454¢ per Kwh

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month 7.232¢ per Kwh

Minimum Bill:

The minimum bill for single-phase service shall be the customer charge.

The minimum bill for three-phase service shall be the customer charge; provided, however, in unusual circumstances where annual kilowatt-hour usage is less than 1,000 times the kilowatts of capacity required, Company may charge a minimum bill of not more than 98 cents per month per kilowatt of connected load.

SPECIAL RATE FOR ELECTRIC SPACE HEATING SERVICE RATE SCHEDULE GS

RATE:

For all consumption recorded on the separate meter during the heating season the rate shall be 4.726¢ per kilowatt-hour.

Minimum Bill:

$6.90 per month for each month of the "heating season." This minimum charge is in addition to the regular monthly minimum of Rate GS to which this rider applies.

LARGE COMMERCIAL RATE (RATE SCHEDULE LC)

Applicable:

In all territory served.

Availability:

This schedule is available for alternating current service to customers whose monthly demand is less than 2,000 kilowatts and whose entire lighting and power requirements are purchased under this schedule at a single service location.

RATE:

Customer Charge: $16.90 per delivery point per month.

Demand Charge:

	Secondary Distribution	Primary Distribution
Winter Rate: (Applicable during 8 monthly billing periods of October through May)		
All kilowatts of billing demand	$7.25 per Kw per month	$5.61 per Kw per month
Summer Rate: (Applicable during 4 monthly billing periods of June through September)		
All kilowatts of billing demand	$10.33 per Kw per month	$8.42 per Kw per month

Energy Charge:

All kilowatt-hours per month	3.272¢

LARGE COMMERCIAL TIME-OF-DAY RATE

Availability:

This schedule is available for alternating current service to customers whose monthly demand is equal to or greater than 2,000 kilowatts and whose entire lighting and power requirements are purchased under this schedule at a single service location.

RATE:

Customer Charge: $17.20 per delivery point per month

Demand Charge:

Basic Demand Charge

Secondary Distribution	$3.68 per Kw per month
Primary Distribution	$1.99 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period but not less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Peak Period Demand Charge

Summer Peak Period	$6.66 per Kw per month
Winter Peak Period	$3.54 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Energy Charge: 3.272¢ per Kwh

Winter-Peak Period is defined as weekdays, except holidays as recognized by company, from 6 AM to 10 PM local time, during the 8 monthly billing periods of October through May.

INDUSTRIAL POWER (RATE SCHEDULE LP)

Availability:

This schedule is available for three-phase industrial power and lighting service to customers whose monthly demand is less than 2,000 kilowatts, the customer to furnish and maintain all necessary transformation and voltage regulatory equipment required for lighting usage. As used herein the term "industrial" shall apply to any activity engaged primarily in manufacturing or to any other activity where the usage for lighting does not exceed 10% of total usage.

RATE:

Customer Charge: $41.70 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution	Transmission Line
All kilowatts of billing demand	$8.99 per Kw per month	$7.02 per Kw per month	$5.86 per Kw per month

Energy Charge:

All kilowatt-hours per month 2.832¢ per Kwh

INDUSTRIAL POWER TIME-OF-DAY RATE
(RATE SCHEDULE LP-TOD)

Applicable:

In all territory served.

Availability:

This schedule is available for three-phase industrial power and lighting service to customers whose monthly demand is equal to or greater than 2,000 kilowatts, the customer to furnish and maintain all necessary transformation and voltage regulatory equipment required for lighting usage. As used herein the term "industrial" shall apply to any activity engaged primarily in manufacturing or to any other activity where the usage for lighting does not exceed 10% of total usage. Company reserves the right to decline to serve any new load of more than 50,000 kilowatts under this rate schedule.

RATE:

Customer Charge: $42.55 per delivery point per month

Demand Charge:

Basic Demand Charge:

Secondary Distribution	$5.26 per Kw per month
Primary Distribution	$3.30 per Kw per month
Transmission Line	$2.10 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period, but not less than 70% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Peak Period Demand Charge:

Summer Peak Period	$5.51 per Kw per month
Winter Peak Period	$2.92 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 70% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Energy Charge: 2.832¢ per Kwh

Summer-Peak Period is defined as weekdays, except holidays as recognized by Company, from 9 AM to 11 PM local time, during the 4 monthly billing periods of June through September.

Winter-Peak Period is defined as weekdays, except holidays as recognized by Company, from 6 AM to 10 PM local time during the 8 monthly billing periods of October through May.

Power Factor Provision

The monthly demand charge shall be decreased .4% for each whole one percent by which the monthly average power factor exceeds 80% lagging and shall be increased .6% for each whole one percent by which the monthly average power factor is less than 80% lagging.

OUTDOOR LIGHTING SERVICE
(RATE SCHEDULE OL)

RATES:

Overhead Service Mercury Vapor	Rate Per Light Per Month
100 watt*	$6.92
175 watt	7.89
250 watt	8.98
400 watt	11.03
400 watt floodlight	11.03
1000 watt	20.38
1000 watt floodlight	20.38
High Pressure Sodium Vapor	
150 watt	$9.89
150 watt floodlight	9.89
250 watt	11.73
400 watt	12.55
400 watt floodlight	12.55
Underground Service Mercury Vapor	
100 Watt - Top Mounted	$12.00
175 Watt - Top Mounted	12.83
High Pressure Sodium Vapor	
100 Watt - Top Mounted	$14.14

* Restricted to those units in service on 5-31-79.

Special Terms and Conditions:

Company will furnish and install the lighting unit complete with lamp, fixture or luminaire, control device and mast arm. The above rates for overhead service contemplate installation on an existing wood pole with service supplied from overhead circuits only; provided, however, that when possible, floodlights served hereunder may be attached to existing metal street lighting standards supplied from overhead service. If the location of an existing pole is not suitable for the installation of a lighting unit, the Company will extend its secondary conductor one span and install an additional pole for the support of such unit. The customer to pay an additional charge of $1.62 per month for each such pole so installed. If still further poles or conductors are required to extend service to the lighting unit, the customer will be required to make a non-refundable cash advance equal to the installed cost of such further facilities.

PUBLIC STREET LIGHTING SERVICE (RATE SCHEDULE PSL)

RATE:

TYPE OF UNIT Overhead Service	Support	Rate Per Light Per Year
100 Watt Mercury Vapor (open bottom fixture)(1)	Wood Pole	$74.57
175 Watt Mercury Vapor	Wood Pole	88.03
250 Watt Mercury Vapor	Wood Pole	100.76
400 Watt Mercury Vapor	Wood Pole	121.45
400 Watt Mercury Vapor (2)	Metal Pole	174.02
400 Watt Mercury Vapor Floodlight	Wood Pole	121.45
1000 Watt Mercury Vapor	Wood Pole	228.43
1000 Watt Mercury Vapor Floodlight	Wood Pole	228.43
150 Watt High Pressure Sodium	Wood Pole	107.36
150 Watt High Pressure Sodium Floodlight	Wood Pole	107.36
250 Watt High Pressure Sodium	Wood Pole	129.36

400	Watt High Pressure Sodium	Wood Pole	136.21
400	Watt High Pressure Sodium Floodlight	Wood Pole	136.21
	<u>Underground Service</u>		
100	Watt Mercury Vapor Top Mounted		121.65
175	Watt Mercury Vapor Top Mounted		133.73
175	Watt Mercury Vapor	Metal Pole	179.67
250	Watt Mercury Vapor	Metal Pole	192.87
400	Watt Mercury Vapor	Metal Pole	228.09
400	Watt Mercury Vapor	Alum. Pole	228.09
400	Watt Mercury Vapor on State of KY Aluminum Pole		137.14
100	Watt High Pressure Sodium Top Mounted		133.73
250	Watt High Pressure Sodium Vapor	Metal Pole	245.48
250	Watt high Pressure Sodium Vapor	Alum. Pole	245.48
250	Watt High Pressure Sodium Vapor on State of KY Aluminum Pole		127.19
400	Watt High Pressure Sodium Vapor	Metal Pole	264.89
400	Watt High Pressure Sodium Vapor	Alum. Pole	264.89
1500	Lumen Incandescent (3)	8-1/2' Metal Pole	99.01
6000	Lumen Incandescent (3)	Metal Pole	131.99

(1) Restricted to those units in service on 5/31/79
(2) Restricted to those units in service on 1/19/77
(3) Restricted to those units in service on 3/1/67

STREET LIGHTING ENERGY RATE
(RATE SCHEDULE SLE)

RATE:

4.021¢ per kilowatt-hour

TRAFFIC LIGHTING ENERGY RATE
(RATE SCHEDULE TLE)

RATE:

5.327¢ per kilowatt-hour

Minimum Bill:

$1.45 per month for each point of delivery.

INTERRUPTIBLE SERVICE

Applicable:

To Large Commercial Rate LC, Rate LC-TOD, Industrial Power Rate LP and Rate LP-TOD.

Availability:

This rider is available for interruptible service to any customer whose interruptible demand is at least 1,000 kilowatts.

Contract Demand:

The contract shall be for a given amount of firm demand which shall be billed at the appropriate standard rate schedule demand charge. Any excess monthly demands above this firm demand shall be considered as interruptible demand.

Rate:

The monthly bill for service under this rider shall be determined in accordance with the provisions of Rate LC, Rate LC-TOD, Rate LP or Rate LP-TOD, except there shall be an interruptible demand credit determined in accordance with one of the following categories of interruptible service:

Interruptible Service Categories	Maximum Annual Hours of Interruption	Monthly Demand Credit ($/Kw/Mo)
1	150	1.18
2	200	1.57
3	250	1.94

The interruptible demand credit shall be applied to the monthly billing demand in excess of the firm contract demand (but not less than 1,000 kilowatts) determined in accordance with the billing demand provision under the applicable rate schedule, except in the case of service under Rate LC-TOD or Rate LP-TOD. The interruptible credit shall be applied to the billing demands as determined for the peak periods only.

Interruption of Service:

The Company will be entitled to require customer to interrupt service at any time and for any reason upon providing at least 10 minutes prior notice. Such interruption shall not exceed 10 hours duration per interruption.

Penalty for Unauthorized Use:

In the event customer fails to comply with a Company request to interrupt either as to time or amount of power used, the customer shall be billed for the monthly billing period of such occurrence at the rate of $15.00 per kilowatt of monthly billing demand. Failure to interrupt may also result in the termination of the contract.

Term of Contract:

The minimum original contract period shall be one year and thereafter until terminated by giving at least 6 months previous written notice, but Company may require that contract be executed for a longer initial term when deemed necessary by the size of the load or other conditions.

Applicability of Terms:

Except as specified above, all other provisions of Rate LC, Rate LC-TOD, Rate LP and Rate LP-TOD shall apply.

SUPPLEMENTAL OR STANDBY SERVICE

Applicable:

To Large Commercial Rate LC, Rate LC-TOD, Industrial Power Rate LP and Rate LP-TOD.

Rate:

Electric service actually used each month will be charged for in accordance with the provisions of the applicable rate schedule; provided, however, that the monthly bill shall in no case be less than an amount calculated at the rate of $5.61 per kilowatt applied to the contract demand.

Special Terms and Conditions:

d. In the event customer's use of service is intermittent or subject to violent fluctuations, the Company will require customer to install and maintain at his own expense suitable equipment to satisfactorily limit such intermittence or fluctuations.

SMALL POWER PRODUCTION AND COGENERATION
PURCHASE SCHEDULE
SPPC-1

Rates for Purchases from
Qualifying Facilities

Capacity component per kilowatt-hour delivered .415¢

Term of Contract:

For contracts which cover the purchase of energy only, the term shall be one year and shall be self-renewing from year to year thereafter, unless cancelled by either party on one year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be 20 years.

SMALL POWER PRODUCTION AND COGENERATION
PURCHASE SCHEDULE
SPPC-II

Rates for Purchases from
Qualifying Facilities

Capacity component per kilowatt-hour delivered .415¢

Term of Contract:

For contracts which cover the purchase of energy only, the term shall be one year and shall be self-renewing from year to year thereafter, unless cancelled by either party on one year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be 20 years.

SPECIAL CONTRACT FOR ELECTRIC SERVICE
ARICO ALLOYS AND CARBIDE SPECIAL CONTRACT

Demand Charge

Primary Power (28,500 Kw)	\$11.37 per Kw per month
Secondary Power (Excess Kw)	\$5.69 per Kw per month
Demand Credit for Primary Interruptible Power (24,500 Kw)	\$1.94 per Kw per month
Energy Charge All KWH	2.005¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
E. I. DUPONT DE NEMOURS SPECIAL CONTRACT

Demand Charge

\$11.02 per Kw of billing demand per month

Energy Charge

2.128¢ per Kwh

SPECIAL CONTRACT FOR ELECTRIC SERVICE
FORT KNOX SPECIAL CONTRACT

Demand Charge

Winter Rate:
(Applicable during 8 monthly billing periods of October through May)

All Kw of Billing Demand	\$6.24 per Kw per month

Summer Rate:
(Applicable during 4 monthly billing periods of June through September)

All Kw of Billing Demand	\$8.42per Kw per month
Energy Charge: All Kwh per month	2.742¢ per Kwh

SPECIAL CONTRACT FOR ELECTRIC SERVICE
LOUISVILLE WATER COMPANY SPECIAL CONTRACT

Demand Charge

\$7.53 per Kw of billing demand per month

Energy Charge

2.261¢ per Kwh

GENERAL RULES

Charge for Disconnecting and Reconnecting Service:

23. A charge of $14.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of the Company's rules and regulations, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

Residential and general service customers may request and be granted a temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $14.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

GAS SERVICES

The Gas Supply Cost component in the following rates has been adjusted to incorporate all changes through PGA 8924-R.

GENERAL GAS RATE
G-1

Curtailment Rules

Delete specific reference.

Availability:

Available for general service to residential, commercial and industrial customers.

Rate:

Customer Charge:

$4.55 per delivery point per month for residential service
$9.25 per delivery point per month for non-residential service

Charge Per 100 Cubic Feet:

Distribution Cost Component	10.820¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	37.802¢

Off-Peak Pricing Provision:

The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by 5.0 cents per 100 cubic feet during the 7 monthly off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE G-1

Availability:

Available to any customer who takes gas service under Rate G-1 and who has installed and in regular operation a gas burning summer air conditioning system with a cooling capacity of three tons or more. The special rate set forth herein shall be applicable during the 5 monthly billing periods of each year beginning with the period covered by the regular June meter reading and ending with the period covered by the regular October meter reading.

Rate:

The rate for "Summer Air Conditioning Consumption," as described in the manner hereinafter prescribed, shall be as follows:

Charge Per 100 Cubic Feet:

Distribution Cost Component	5.820¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	32.802¢

All monthly consumption other than "Summer Air Conditioning Consumption" shall be billed at the regular charges set forth in Rate G-1.

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheets No. 12, 13 and 14 of this Tariff.

SEASONAL OFF-PEAK GAS RATE
G-6

Curtailment Rules

Delete specific reference.

Availability:

Available during the 275-day period from March 15 to December 15 of each year to commercial and industrial customers using over 50,000 cubic feet of gas per day who can be adequately served from the Company's existing distribution system without impairment of service to other customers and who agree to the complete discontinuance of gas service for equipment served hereunder and the substitution of other fuels during the 3-month period from December 15 to March 15. No gas service whatsoever to utilization equipment served hereunder will be supplied or permitted to be taken under any other of the Company's gas rate schedules during such 3-month period. Any gas utilization equipment on customer's premises of such nature or used for such purposes that gas service thereto cannot be completely discontinued during the period from December 15 to March 15 will not be eligible for service under this rate, and gas service thereto must be segregated from service furnished hereunder and supplied through a separate meter at the Company's applicable standard rate for year-around service. This rate shall not be available for loads which are predominantly space heating in character or which do not consume substantial quantities of gas during the summer months.

Rate:

Customer Charge:	$20.00 per delivery point per month

Charge Per 100 Cubic Feet:

Distribution Cost Component	5.300¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	32.282¢

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

Minimum Bill:

The customer charge.

Prompt Payment Provision:

The monthly bill will be rendered at the above net charges (including net minimum bills when applicable) plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within 15 days from date.

RATE FOR UNCOMMITTED GAS SERVICE
G-7

Rate:

Charge Per 100 Cubic Feet:

Distribution Cost Component	4.300¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	31.282¢

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

Incremental Pricing:

Delete from Tariff.

DUAL-FUEL OFF-PEAK GAS SPACE HEATING RATE
G-8

Service to be supplied under G-1.

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE
G-8

Service to be supplied under G-1.

GAS TRANSPORTATION SERVICE/STANDBY
RATE TS

Availability:

Available to commercial and industrial customers served under Rates G-1 and G-6 who consume at least 50 Mcf per day at each individual point of delivery, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's natural gas supplier, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any transportation service hereunder will be conditioned on the Company being able to retain or secure adequate standby quantities of natural gas from its supplier. In addition, transportation service hereunder shall be subject to the terms and conditions herein set forth and to the reserved right of Company to decline to initiate such service whenever, in Company's sole judgment, the performance of the service would be contrary to good operating practice or would have a detrimental impact on other customers served by Company.

Rate:

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $90.00 per delivery point per month.

	G-1	G-6
Distribution Charge Per Mcf	$1.0820	$0.5300
Pipeline Supplier's Demand Component	.4671	.4671
Total	$1.5491	$0.9971

The "Distribution Charge" applicable to G-1 monthly quantities in excess of 100 Mcf shall be reduced by $.50 per Mcf during the 7 off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component:

Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's quarterly Gas Supply Clause.

Standby Service:

Company will provide standby quantities of natural gas hereunder for purposes of supplying customers' requirements should customer be unable to obtain sufficient transportation volumes. Such standby service will be provided at the same rates and under the same terms and conditions as those set forth in the Company's applicable rate schedule under which it sells gas to customer.

Receipts and Deliveries:

Customer shall not cause quantities of gas to be delivered to Company's system which exceed the quantities delivered to the customer's place of utilization by more than 5%. Any imbalance between receipts by Company on behalf of customer and quantities delivered to customer shall be corrected as soon as practicable, but in no event shall imbalance be carried longer than 60 days.

Special Terms and Conditions:

(2) At least 10 days prior to the beginning of each month, customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for customer's account. Customer shall give Company at least 24 hours prior notice of any subsequent changes to scheduled deliveries. Customer shall cause gas delivered into Company's system for customer's account to be as nearly as practicable at uniform daily rates of flow, and deliveries of such gas by Company to customer hereunder will also be effected as nearly as practicable on the same day as the receipt thereof.

GAS TRANSPORTATION SERVICE
RATE T

Applicable:

In all territory served.

Availability:

Available to commercial and industrial customers served under Rate G-7 who consume at least 50 Mcf per day at each individual point of delivery, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's natural gas supplier, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any such transportation service hereunder shall be conditioned on the Company being granted a reduction in D-1 and D-2 billing demands by its pipeline supplier corresponding to the customer's applicable transportation quantities. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the reserved right of Company to decline to initiate such service whenever, in Company's sole judgment, the performance of the service would be contrary to good operating practice or would have a detrimental impact on other customers served by Company.

Rate:

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $90.00 per delivery point per month.

Distribution Charge Per Mcf: $0.43

Receipts and Deliveries:

Customer will deliver or cause to be delivered daily and monthly quantities of natural gas to Company's system which correspond to the daily and monthly quantities delivered hereunder by Company to customer's place of utilization and, in no case, shall the variation in quantities be greater than 5%. Any imbalance between receipts by Company on behalf of customer and quantities delivered to customer shall be corrected as soon as practicable, but in no event shall imbalance be carried longer than 60 days.

Special Terms and Conditions:

(1) Service under this rider shall be performed under a written contract between customer and Company setting forth specific arrangements as to volumes to be transported by Company for customer, points of delivery, methods of metering, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

(2) At least 10 days prior to the beginning of each month, customer shall provide Company with a schedule setting forth daily

volumes of gas to be delivered into Company's system for customer's account. Customer shall give Company at least 24 hours prior notice of any subsequent changes to scheduled deliveries. Customer shall cause gas delivered into Company's system for customer's account to be as nearly as practicable at uniform daily rates of flow, and deliveries of such gas by Company to customer hereunder will also be effected as nearly as practicable on the same day as the receipt thereof. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

(3) In no case will Company be obligated to supply greater quantities hereunder than those specified in the written contract between customer and Company.

(4) Volumes of gas transported hereunder will be determined in accordance with Company's measurement as set forth in the general rules of this Tariff.

(5) All volumes of natural gas transported hereunder shall be of the same quality and meet the same specifications as that delivered to Company by its pipeline supplier.

(6) Company will have the right to curtail or interrupt the transportation or delivery of gas to any customer hereunder when, in the Company's judgment, such curtailment is necessary to enable Company to maintain deliveries to residential and high priority customers or to respond to an emergency.

(7) Should customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such customer requirements.

Applicability of Rules:

Service under this Rider is subject to Company's rules and regulations governing the supply of gas service as incorporated in this Tariff, to the extent that such rules and regulations are not in conflict with nor inconsistent with the specific provisions hereof.

GAS SUPPLY CLAUSE
GSC

Applicable to:

All gas sold.

Gas Supply Cost Component (GSCC): (PGA) 8924-R)

Gas Supply Cost	27.043¢
Gas Cost Actual Adjustment (GCAA)	0.241
Gas Cost Balance Adjustment (GCBA)	(0.269)

Refund Factors (RF) continuing for 12 months from the effective date of each or until Company has discharged its refund obligation thereunder:

Refund Factor Effective August 1, 1987 from 8924-O	(0.020)	
Refund Factor Effective November 1, 1987 from 8924-P	(0.013)	
Total of Refund Factors Per 100 Cubic Feet		(0.033)
Total Gas Supply Cost Component Per		26.982¢

The monthly amount computed under each of the rate schedules tp which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each 3-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each 3-month period determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected total purchases at the filed rates of Company's wholesale supplier of natural gas, plus

(b) Other gas purchases for system supply, minus

(c) Portion of such purchase cost expected to be used for non-Gas Department purposes, minus

(d) Portion of such purchase cost expected to be injected into underground storage, plus

(e) Expected underground storage withdrawals at the average unit cost of working gas contained therein.

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous quarter's expected gas cost and the actual cost of gas during that quarter.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 12 of this Tariff.

Company shall file a revised Gas Supply Cost Component (GSCC) every 3 months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. Such filing shall be made at least 30 days prior to the beginning of each 3-month period and shall include the following information:

(1) A copy of the tariff rate of Company's wholesale gas supplier applicable to such 3-month period.

(2) A statement, through the most recent 3-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.

(3) A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such 3-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each 3-month period.

In the event that the Company receives from its supplier a refund of amounts paid to such supplier with respect to a prior period, the Company will make adjustments in the amounts charged to its customers under this provision, as follows:

(1) The "Refundable Amount" shall be the amount received by the Company as a refund less any portion thereof applicable to gas purchased for electric energy production. Such refundable amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the 12-month period which commences with implementation of the next gas supply clause filing, thus determining a "Refund Factor."

(2) Effective with the implementation of the next Gas Supply Clause filing, the Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be

applicable during the subsequent 12-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the refundable amount.

(3) In the event of any large or unusual refunds, the Company may apply to the Public Service Commission for the right to depart from the refund procedure herein set forth.

GENERAL RULES

Charges for Disconnecting and Reconnecting Service:

23. A charge of $14.00 will made to cover disconnection and reconnection of gas service when discontinued for non-payment of bills or for violation of the Company's rules and regulations, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

Customers under General Gas Rate G-1 may request and be granted a temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $14.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of Adjustment
for
Group Life Insurance

	Amount	Insurance Coverage		Rate	Month	Total Amount
Union Employees:						
A. For first $5,000 of Coverage						
2,459 employees X $5,000	$12,295,000	100%	$12,295,000	.59/1000	12	$ 87,048
B. For additional coverage						
Wages & Salaries	74,634,771	125	93,293,464			
Increase in Salaries - 4%	2,985,390	125	3,731,738			
			97,025,202			
LESS: First $5,000			12,295,200			
			$84,730,002	.44/1000	12	447,372
Union Subtotal						$534,420
Nonunion Employees:						
A. For first $5,000 of Coverage						
1,242 employees X $5,000	6,210,000	100	6,210,000	.59/1000	12	43,968
B. For additional coverage						
Wages & Salaries	39,545,720	125	49,432,150			
Increase in Salaries	275,825	125	344,781			
			$49,776,931			
LESS: First $5,000			6,210,000			
			$43,566,931	.44/1000	12	230,02
Nonunion Subtotal						$273,99
TOTAL						$808,41
Operating Portion @ 72%						582,06
LESS: Test Year Amount per Books						473,68
NET ADJUSTMENT						$108,38

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of
Federal and State Unemployment for
Test Year Ended August 31, 1987

	Federal Unemployment	State Unemployment
Total Employees as of 9/6/87	3,920	3,920
Base Wage	$ 7,000	$ 8,000
Wages Subject to Tax	$27,440,000	$31,360,000
Rate/KIUC Information Request No. 2	.8%	1.2%
Tax	$ 219,520	$ 376,320
Operating Percentage	72%	72%
	$ 158,054	$ 270,950
Operating Tax for Test Year Ended 8/31/87		
January-December 1986	149,039	298,447
January-August 1986	<145,554>	<291,919>
January-August 1987	145,655	242,849
TEST YEAR UNEMPLOYMENT	$ 149,140	$ 249,377
ADJUSTMENT	$ 8,914	$ 21,573
Electric - 77%	6,864	16,611
Gas - 23%	2,050	4,962
	$ 8,914	$ 21,573

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of
Year-End Volumes of Business
Expense Adjustment

Total Expenses		$255,400,862 [1]
Wages & Salaries:		
Test Year Actual		<66,332,568> [2]
		$189,068,294
Total Electric Operations Revenues		$476,397,820 [3]
Sales to Other Utilities		<1,877,587> [4]
		$474,520,233
Ratio =	$\frac{\$189,068,294}{474,520,233}$ = 39.84%	
Revenue Increase Per Adjustment		$ 3,627,565
		.3984
		$ 1,445,222
Net Adjustment:		
Revenues		$ 3,627,565
Expenses		4,445,222
		$ 2,182,343

1 Hart Exhibit 6, page 3, lines 1-6; August 31, 1987 Monthly Report, page 19.

2 Response to the Commission Order dated November 12, 1987, Item No. 16(d), page 2.

3 Hart Prepared Testimony, Exhibit 1, Column 5.

4 *Ibid.*

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE SALE AND DETARIFFING OF EMBEDDED CUSTOMER PREMISES EQUIPMENT PHASE 5 NETWORK CHANNEL TERMINATION EQUIPMENT	))))	ADMINISTRATIVE CASE NO. 269

O R D E R

Introduction

On April 18, 1988, the Commission issued an Order establishing Phase 5 of this case and ordered all Local Exchange Carriers ("LECs") to submit certain information regarding Network Channel Terminating Equipment[1] by May 18, 1988. This Order was issued in conjunction with the Federal Communications Commission ("FCC") Eighth Report and Order in CC Docket No. 81-893 released on January 29, 1988 which ordered detariffing of embedded digital Network Channel Terminating Equipment effective July 1, 1988. The disposition of analog Network Channel Terminating Equipment is being considered in FCC Docket No. 83-752 and is, therefore, not a part of this proceeding. All LECs responded to the Commission Order to submit information concerning Network Channel Terminating Equipment.

1 Network Channel Terminating Equipment is a generic term for interface devices located on customers premises to perform functions necessary for using a transmission channel for digital communications.

Discussion

In its response to the Commission's Order, Cincinnati Bell Telephone Company ("Cincinnati Bell") stated that in accordance with the Order in this case dated September 10, 1985, which ordered independent telephone companies to detariff and transfer to unregulated operations embedded customer premises equipment no later than December 31, 1987, it has detariffed all Network Channel Terminating Equipment in Kentucky.

GTE South Incorporated has also stated that all digital Network Channel Terminating Equipment had been detariffed and transferred to unregulated activities as of December 31, 1987 although GTE did not specifically state whether the transfer was interstate or intrastate investment.

South Central Bell Telephone Company in accordance with the Eighth Report and Order, plans to detariff digital Network Channel Terminating Equipment effective July 1, 1988.

The response of Alltel Kentucky, Inc. urged the Commission to differentiate between digital and analog Network Channel Terminating Equipment and to be consistent with the FCC which has allowed carriers to provide Network Channel Terminating Equipment that supports only loopback functions as a part of regulated basic services.

Finally, several of the small companies responded that the only investment they had similar in nature to that described by the Commission, was network channel terminating units associated with special access circuits. Based upon the descriptions provided by these companies, these network channel terminating units appear to be a part of basic network facilities and therefore would not be considered to be customer premises equipment.

FINDINGS AND ORDERS

The Commission, having considered the evidence of record and being advised is of the opinion that:

1. Effective no later than July 1, 1988 digital Network Channel Terminating Equipment should be detariffed by all LECs.

2. Analog Network Channel Terminating Equipment shall remain under tariff pending the outcome of the FCC investigation in CC Docket No. 83-752.

3. Loopback testing shall remain a tariffed service.

4. Network channel terminating units associated with the provision of special access which are analog in nature appear to be a part of basic network facilities and therefore would not be considered to be customer premise equipment.

IT IS THEREFORE ORDERED that:

1. All digital Network Channel Terminating Equipment CPE shall be detariffed and transferred to unregulated activities effective no later than July 1, 1988.

2. Loopback testing shall remain a tariffed service.

3. Network channel terminating units provided in connection with special access service which are analog in nature appear to be a part of basic network facilities and therefore would not be considered customer premise equipment and will remain under tariff pending a decision in FCC CC Docket No. 83-752.

4. All local exchange carriers shall file tariffs within 30 days of this Order reflecting the detariffing of Network Channel Terminating Equipment effective no later than July 1, 1988.

Done at Frankfort, Kentucky, this 1st day of July, 1988.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ATTEST:

Executive Director

EXHIBIT__(LK-PSC-13-2)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 90-158

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 90-158

O R D E R

On June 29, 1990, Louisville Gas and Electric Company ("LG&E") filed an application with the Commission requesting authority to increase its electric and gas rates for service rendered on and after August 1, 1990. The proposed rates would increase annual electric revenues by $31,015,938, an increase of 6.22 percent, and annual gas revenues by $3,837,454, an increase of 2.24 percent. These increases represent an annual increase in total operating revenues of $34,853,392, or 5.43 percent, based on normalized test-year sales. This Order grants an increase in annual electric revenues of $5,451,758, an increase of 1.17 percent, and an increase in annual gas revenues of $524,487, an increase of .30 percent. These increases represent an annual increase in total operating revenues of $5,976,245, or .93 percent, based on normalized test-year sales.

The Commission granted motions to intervene filed by the Attorney General, by and through his Utility and Rate Intervention Division ("AG"); Jefferson County ("Jefferson"); the city of Louisville ("Louisville"); the Department of Defense of the United States ("DOD"); the Kentucky Industrial Utility Customers

("KIUC"); the Paddlewheel Alliance ("Paddlewheel"); the Kentucky Cable Television Association, Inc. ("KCTA"); the Metro Human Needs Alliance, Inc., which assists low-income households ("MHNA"); the International Brotherhood of Electrical Workers, Local 2100; and Reynolds Metals Company. The Commission suspended the proposed rate increase through December 31, 1990 in order to conduct an investigation into the reasonableness of the proposed rates. A public hearing was held in the Commission's offices in Frankfort, Kentucky, on November 7-9, 19-21, and 26, 1990 with all parties of record represented. Simultaneous briefs were filed on December 14, 1990. All information requested during the hearing has been submitted.

COMMENTARY

LG&E is a privately owned electric and gas utility which generates, transmits, distributes, and sells electricity to approximately 321,300 consumers in Jefferson County and in portions of Bullitt, Hardin, Henry, Meade, Oldham, Shelby, Spencer, and Trimble counties. LG&E distributes and sells natural gas to approximately 243,400 consumers in Jefferson County and in portions of Barren, Bullitt, Green, Hardin, Hart, Henry, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Trimble, and Washington counties.

TEST PERIOD

LG&E proposed the 12-month period ending April 30, 1990 as the test period for determining the reasonableness of the proposed rates. LG&E also proposed to reflect the impact of the commercialization of the Trimble County Unit No. 1 ("Trimble

County") Generating Plant which was scheduled for late December 1990. Jefferson, Louisville, and Paddlewheel ("Jefferson et al.") and KIUC opposed this approach, stating that LG&E had created a hybrid test year which was neither fully historic nor fully projected. The Commission believes it is reasonable to utilize the 12-month period ending April 30, 1990 as the test period in this proceeding. In utilizing the historic test period, the Commission has given full consideration to appropriate known and measurable changes.

NET ORIGINAL COST RATE BASE

Trimble County

LG&E proposed a total company net original cost rate base of $1,444,036,873. Trimble County was reflected in rate base by including test year end Construction Work in Progress ("CWIP") of $677,170,687, plus estimated additional expenditures through December 31, 1990 of $37,829,317, less $178,750,000 to reflect the 25 percent disallowance for Trimble County ordered by the Commission in Case No. 9934.[1] LG&E also included in its proposed accumulated depreciation the first year depreciation expense on the December 31, 1990 estimated level of investment in Trimble County, exclusive of the 25 percent disallowance. LG&E cited two reasons for including Trimble County in the net original cost rate base. First, it stated that the Trimble County expenditures are known and measurable; and second, it claimed that the Settlement Agreement, Article IX, approved in Case No. 10320,[2] provide an

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[1] Case No. 9934, A Formal Review of the Current Status of Trimble County Unit No. 1, Order dated July 1, 1988.

absolute right to recover 75 percent of its Trimble County investment, including depreciation.

While the AG, Jefferson et al., and KIUC all filed testimony opposing LG&E's proposed treatment of Trimble County, none of these intervenors prepared a net original cost rate base. Their testimony focused on the impact that LG&E's proposals had on total capitalization, discussed later in this Order.

The Commission finds that the post test-year Trimble County expenditures are not known and measurable but, rather, are a moving target. On numerous occasions during the course of this case, LG&E revised its estimated December 31, 1990 level for Trimble County CWIP. In fact, LG&E's most recent revision discloses that almost $11,000,000 of Trimble County CWIP will not be spent until after January 1, 1991.

In proposing this rate base treatment for Trimble County, LG&E has ignored a basic concept of rate-making, the matching principle. While all rate base items except Trimble County are established at actual April 30, 1990 levels, LG&E has included a post test-year plant addition for Trimble County CWIP and the related accumulated depreciation at the estimated December 31, 1990 level. The Commission has a well-established, rate-making policy on the inclusion of post test-period plant additions. All utilities under the Commission's jurisdiction were given notice that, if a historic test period is used, adjustments for post

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2 Case No. 10320, An Investigation of Electric Rates of Louisville Gas and Electric Company to Implement a 25 Percent Disallowance of Trimble County Unit No. 1, Order dated October 2, 1989.

test-period plant additions should not be requested unless all revenues, expenses, rate base, and capital items have been updated to the same period as the plant additions.[3] LG&E acknowledged that it was aware of this policy but argued that it should not apply to this case because the policy was announced after the Settlement Agreement was signed on August 11, 1989.

The Commission is not persuaded by LG&E's argument. The date that the Settlement Agreement was signed has no particular significance in determining the applicability of the rate-making policy announced on August 22, 1989 in Case Nos. 10201[4] and 10481. The Settlement Agreement did not become binding and enforceable until approved by the Commission on October 2, 1989, six weeks after the Commission declared that:

> Therefore, in cases filed after this decision is issued, the Commission gives notice to Columbia [Kentucky-American] and other utilities under its jurisdiction that: 1) adjustments for post test-period additions to plant in service should not be requested unless all revenues, expenses, rate base, and capital items have been updated to the same period as the plant additions. . . .[5]

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3 Case No. 10481, Notice of Adjustment of the Rates of Kentucky-American Water Company Effective on February 2, 1989, Order dated August 22, 1989, page 5.

4 Case No. 10201, Adjustment of Rates of Columbia Gas of Kentucky, Inc., Order dated August 22, 1989.

5 Case No. 10201, Order dated August 22, 1989, page 6; and Case No. 10481, Order dated August 22, 1989, page 5.

This rate-making policy, having been announced before the Settlement Agreement was approved, and long before this rate case was filed, is applicable and controlling. Further, there is no language in the October 2, 1989 Order approving the Settlement Agreement that allows LG&E to disregard this policy.

Nevertheless, this Commission also recognizes that Trimble County represents a significant addition to LG&E's utility plant in service. By the date the rates authorized in this Order take effect, Trimble County will be in commercial operation and all Trimble County expenditures will be reclassified from CWIP to plant-in-service. Therefore, the Commission must consider the commercialization of a major plant addition and at the same time adhere to rate-making concepts, time tested for fairness and reasonableness.

We believe it fair and reasonable in this instance to include in LG&E's net original cost rate base the test-year-end Trimble County CWIP. This amount, net of the 25 percent disallowance, is $507,878,016. This rate-making treatment is essentially the same that LG&E has received throughout the construction of Trimble County. The Commission also finds it reasonable in this instance to allow depreciation expense on 75 percent of the Trimble County CWIP balance as of the end of the test year. The first year depreciation expense has been included in the accumulated depreciation used in determining the net original cost rate base. This approach properly recognizes the known and measurable fixed cost associated with the commercialization of Trimble County. The Commission cannot and will not include in rate base the post test-period plant additions for Trimble County or the related first year depreciation expense. To do otherwise would disregard established, and we feel fair, just and reasonable rate-making practices enunciated and adopted in prior Commission decisions concerning post test-period plant additions.

Fuel Inventory

LG&E proposed to include $14,297,235 as fuel inventory in its rate base calculations. This amount represents the test-year end balance for the fuel inventory account. During the hearing, LG&E indicated that it began to purchase coal for Trimble County in January 1990, but had not adjusted the fuel inventory to reflect a 25 percent disallowance of the Trimble County coal. The AG proposed to remove 25 percent of the increase in the fuel inventory between April 30, 1989 and April 30, 1990, stating the entire increase had to be related to Trimble County.

Based on a monthly account balance for fuel inventory review, the Commission believes it is more appropriate to use a 13-month average balance for fuel inventory in the calculation of rate base. The use of a 13-month average balance is consistent with our usual practice. The Commission also believes it is reasonable to remove from the fuel inventory 25 percent of the coal inventory related to Trimble County coal. The 13-month average balance for fuel inventory, including the Trimble County coal was $10,280,683.[6] The Commission has calculated a 13-month average balance, removing the Trimble County coal from each monthly

6 Response to Commission's Order dated June 29, 1990, Item 9.

balance, and finds that $10,270,961 should be used in the calculation of rate base.

Materials, Supplies, and Prepayments

In determining its net original cost rate base, LG&E used the test-year end balances for materials, supplies, and prepayments. The AG proposed to remove 25 percent of the increase in materials and supplies between April 30, 1989 and April 30, 1990, stating the entire increase had to be related to Trimble County. The Commission has reviewed the monthly account balances for these accounts, and as discussed previously, believes it is more appropriate to use a 13-month average balance for these accounts in the calculation of rate base. The Commission also believes it is reasonable to remove from materials and supplies 25 percent of any amounts related to Trimble County. During the hearing, LG&E indicated that $1,945,000[7] was included in materials and supplies for Trimble County. The 13-month average balance for materials and supplies, including the Trimble County materials and supplies, was $32,691,260.[8] The Commission would prefer to adjust the Trimble County amounts out on a monthly basis, and then compute the 13-month average. In this instance, the detailed information

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7 Transcript of Evidence ("T.E."), Volume IV, November 19, 1990, pages 181 and 182.

8 Response to Commission's Order dated June 25, 1990, Item 9.

is not available. Therefore, the Commission has deducted $486,250[9] from the $32,691,260 average, and included $32,205,010 in rate base for materials and supplies. We included $748,304[10] for prepayments in our calculation of rate base.

Stores Expense

The AG also proposed to remove 25 percent of the increase in stores expense between April 30, 1989 and April 30, 1990, for the same reason stated in his adjustment to materials and supplies. At the hearing, LG&E stated that $434,000 in stores expense was related to Trimble County.[11] The Commission believes it is appropriate to remove 25 percent of its Trimble County stores expense from the rate base calculations. The test-year-end balance of $5,790,584 has been reduced by $108,500[12] to reflect the removal of the 25 percent Trimble County stores expense.

Gas Stored Underground

LG&E proposed to include $20,450,243 as gas stored underground in its calculation of rate base. This amount represented a 12-month average balance of the gas stored underground account. Again we believe it is more reasonable to use the 13-month average balance, and have included $19,515,080 as gas stored underground in the calculation of rate base.

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9 $1,945,000 x 25 percent = $486,250.

10 Response to Commission's Order dated June 29, 1990, Item 9.

11 T.E., Volume IV, November 19, 1990, pages 181 and 182.

12 $434,000 x 25 percent = $108,500.

Cash Working Capital Allowance

LG&E determined its cash working capital allowance using the 45 day or 1/8 formula methodology. This Commission has traditionally used this approach in rate cases and do again here. We have adjusted the allowance for cash working capital to reflect the accepted pro forma adjustments to operation and maintenance expenses.

In determining the cash working capital allowance, LG&E deducted from the operation and maintenance expenses the gas supply expenses. The level of gas supply expenses removed did not equal the amount LG&E deducted in its operating expense adjustment for gas supply expenses. It is best to use the same amount in both adjustments. Therefore, we have used the operating expense adjustment level of gas supply expenses in the calculation of the cash working capital allowance.

Based upon the previous findings, we have determined the net original cost rate base for LG&E at April 30, 1990 to be as follows:

	Electric	Gas	Total
Total Utility Plant	$1,915,177,722	$221,751,683	$2,136,929,405
Add:			
Materials & Supplies	46,804,173	1,353,882	48,158,055
Gas Stored Underground	0	19,515,080	19,515,080
Prepayments	621,092	127,212	748,304
Cash Working Capital	32,815,128	4,441,938	37,257,066
Subtotal	$ 80,240,393	$ 25,438,112	$ 105,678,505
Deduct:			
Reserve for Depreciation	529,783,546	84,484,852	614,268,398
Customer Advances	1,572,719	5,134,306	6,707,025
Accumulated Deferred Taxes	193,385,140	19,093,760	212,478,900
Investment Tax Credit (Prior Law)	1,127,320	427,400	1,554,720
Subtotal	$ 725,868,725	$109,140,318	$ 835,009,043
NET ORIGINAL COST RATE BASE	$1,269,549,390	$138,049,477	$1,407,598,867

Reproduction Cost Rate Base

LG&E presented a reproduction cost rate base of $2,605,266,805,[13] which included electric facilities of $2,238,145,899 and gas facilities of $367,120,906. LG&E estimated the value of plant in service, plant held for future use, and CWIP at the end of the test year. LG&E also reflected the same adjustments it had included in its net original cost rate base. We have given consideration to the proposed reproduction cost rate base.

CAPITAL

LG&E proposed a total capitalization of $1,384,481,820.[14] Included in the total capitalization were five adjustments, which

13 Fowler Direct Testimony, Exhibit 5.

14 Fowler Direct Testimony, Exhibit 2, page 1 of 2.

LG&E allocated on a pro rata basis to all components of capital. The five adjustments were for the Job Development Investment Tax Credit ("JDIC"), the 25 porcent disallowance of test year Trimble County CWIP, the unamortized balance of extraordinary retirements as determined by the Commission in Case No. 10064,[15] the estimated additional expenditures for Trimble County through December 31, 1990 net of the 25 percent disallowance, and the capital costs relating to LG&E's new office building.

The AG proposed a total capitalization of $1,352,739,019.[16] The AG added to total debt capital the difference between the 12-month average balance of gas stored underground and the April 30, 1990 balance. The AG deducted from common equity the entire 25 percent disallowance of test-year Trimble County CWIP and 25 percent of the net increase in fuel and supplies increases. After making these adjustments, the AG allocated on an adjusted pro rata basis the JDIC, the unamortized balance of extraordinary retirements, and the capital costs relating to LG&E's new office building. The AG stated that the adjustment to debt capital was necessary because the test-year end balance was not representative of the 12-month average balance, and it was logical to assume that the gas balances were financed by short-term debt since they varied greatly during the test year. The AG's proposal to remove

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15 Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, Order dated July 1, 1988.

16 DeWard Direct Testimony, Exhibit TCD-1, Schedule 3.

the 25 percent Trimble County CWIP disallowance totally from common equity was based on the Settlement Agreement approved in Case No. 10320, which assigned any benefits, profits, or entitlements realized on the disallowed 25 percent of Trimble County to the shareholders of LG&E. The AG stated that LG&E had put itself at risk for both the costs and rewards related to the 25 percent disallowance. MHNA supported the AG's position on this issue.[17] The AG stated that it was logical that LG&E would begin to increase levels of fuel and supplies for Trimble County and that 25 percent of those increases should also be removed.

KIUC proposed a total capitalization of $1,356,100,000.[18] KIUC began with LG&E's total proposed capitalization and removed the pro rata allocation of the estimated additional expenditures for Trimble County through December 31, 1990. KIUC stated that LG&E had created a hybrid historic and forecasted test year, inconsistently relying upon actual historic costs in some instances and totally forecasted costs in other instances.[19]

Jefferson et al. did not propose an amount for total capitalization, but took issue with LG&E's proposal to include the estimated additional expenditures for Trimble County through December 31, 1990. Jefferson et al. stated that LG&E's application had to be evaluated using the historic test year

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17 Brief of MHNA, pages 7 and 8.

18 Kollen Direct Testimony, Table 6, page 42.

19 Id., page 13.

approach, and these additional expenditures did not constitute known and measurable items.

The Commission does not agree that an adjustment to the capitalization is necessitated by the use of an average balance for gas stored underground in the rate base determination. Nor do we agree with the argument that LG&E finances its gas stored underground exclusively through debt capital. In determining the capitalization of a utility, the Commission establishes the overall embedded capital needs which includes working capital items which vary in value throughout the course of a 12-month test period. These variations are sufficient to compensate LG&E for the monthly variations in gas stored underground. Such an adjustment is not necessary in this case.

Concerning the AG's proposal to remove the entire 25 percent disallowance of Trimble County CWIP from common equity, the Commission has ruled in prior cases that the investment in utility plant cannot be traced to specific capital sources. The AG presented no evidence to demonstrate that this investment actually came from common equity alone. Trimble County's construction has been financed by all components of capital, not solely by common equity. It is reasonable to allocate the disallowance on a pro rata basis, in order to reflect this fact. The Commission notes the inconsistency of the AG's position on this adjustment. While proposing a higher level of debt for capitalization, this higher level of debt was not reflected in the AG's proposed rate of return.

The Commission has determined that LG&E's total test-year end capitalization should be $1,355,523,360. The Commission has accepted all of LG&E's proposed adjustments to capitalization with the exception of the estimated additional expenditures on Trimble County through December 31, 1990. As has been discussed earlier in this Order, the Commission has determined that it is not reasonable nor equitable to include these estimated expenditures in rate base without concurrent adjustments to revenues and expenses. Likewise, capitalization must reflect only the level of Trimble County expenditures as of test-year end. The Commission has also adjusted the capitalization for the amount removed from rate base relating to the Trimble County coal inventory, materials and supplies, and stores expense.

PROPOSED PHASE II PROCEEDING

LG&E proposed a "Phase II" proceeding in addition to the current rate case. As proposed, Phase II would establish a process whereby LG&E could recover the allowable 75 percent portion of operation and maintenance expenses associated with the operation of Trimble County. Four areas would be addressed in Phase II. LG&E proposed to file with the Commission calculations annualizing the first three months of actual operating and maintenance expenses at Trimble County, as adjusted for unrepresentative costs. Operating expenses would be reduced by any Trimble County labor expenses recovered in this proceeding. Operating and maintenance expenses would also be reduced by 25 percent of the administrative and general expenses associated with the operation of Trimble County. Additional adjustments would be made to reduce the operating and maintenance expenses by the net revenues realized from off-system sales attributable to the allowable 75 percent portion of Trimble County and depreciation on Cane Run Unit No. 3, if the unit has been retired.[20] LG&E offered this process as a means to avoid the expenses and time associated with additional rate case proceedings, reduce the effects of regulatory lag, avoid the problems associated with a forecasted test year proceeding, and benefit LG&E's customers by allowing it to avoid future rate filings for a period of time.[21]

The AG, KIUC, and Jefferson et al. are opposed to the Phase II proposal. The AG questioned LG&E's willingness to provide information necessary to evaluate such a filing and how representative three months of operational data and off-system sales would be on a going forward basis.[22] KIUC characterized it as an attempt to inappropriately accelerate its Trimble County cost recovery and that the plan was premature and poorly designed.[23] Jefferson et al. cited problems with the three months chosen for annualization, the complexity of calculating the annualization, and how known and measurable the final results would be.[24]DOD stated that the proposal was too narrow in scope.[25]

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20 Fowler Direct Testimony, page 31.

21 Id., page 3.

22 DeWard Direct Testimony, pages 53 and 54.

23 Kollen Direct Testimony, pages 5 and 22.

24 Kinloch Direct Testimony, pages 15 and 16.

25 Brief of DOD, page 11.

The Commission does not believe it is reasonable to accept the Phase II proposal. The abbreviated proceeding would make it difficult to properly match revenues, expenses, rate base, and capital items. Significant non-Trimble County events would be excluded from Phase II. There is insufficient evidence to demonstrate that an annualization of three months of actual Trimble County data would be representative of going forward conditions.

REVENUES AND EXPENSES

For the test period, LG&E had actual net operating income of $121,674,031.[26] LG&E originally proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions which resulted in an adjusted net operating income of $122,043,734.[27] Subsequently, LG&E proposed several correcting adjustments. The proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications.

Revenue Normalization - Electric

LG&E proposed normalized electric operating revenues of $502,388,879 based on the rates in effect at the end of the test year. In normalizing its electric revenues, LG&E made adjustments to reflect year-end customers, to eliminate a non-recurring refund, and to eliminate the effect of changing to the unbilled method of recording revenues midway through the test year.

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26 Fowler Direct Testimony, Exhibit 1, page 1 of 3.

27 Id., page 3 of 3.

KIUC proposed an adjustment to increase normalized electric revenues by $4,896,459 to recognize for rate-making purposes the initial booking of unbilled revenues reported by LG&E in January 1990. The adjustment proposed by KIUC reflects a 3-year amortization of LG&E's initial booked amount of $14,689,378. KIUC contends that a one-time event such as LG&E's initial booking of unbilled revenues should be given rate-making treatment consistent with that afforded the one-time downsizing for which LG&E proposed a 3-year amortization. KIUC maintains that both the downsizing costs and the initial booking of unbilled revenues should either be amortized and included in the determination of LG&E's revenue requirements or treated as one-time, non-recurring events that were booked during the test year, will not impact future earnings, and should be excluded from the determination of LG&E's revenue requirements.

LG&E's proposed adjustments are reasonable for determining normalized electric revenues. No adjustment should be made to amortize the amounts included in LG&E's initial booking of unbilled revenues. The initial booking is a one-time occurrence recorded during the test year that will not impact future periods during which the approved rates will be in effect.

Revenue Normalization - Gas

LG&E proposed normalized gas operating revenues of $194,585,467 based on the rates in effect at the time of filing its application. In normalizing its gas revenues, LG&E made adjustments to reflect normal weather conditions and year-end customers. LG&E eliminated the effect of changing to the unbilled method of recording revenues and adjusted its gas cost revenues to $130,285,428 based on its wholesale gas cost in effect at the time the application was filed.

KIUC proposed an adjustment to increase LG&E's normalized gas revenues by $5,034,036 to reflect a 3-year amortization of LG&E's initial booking of unbilled revenues. This was the same adjustment KIUC proposed for LG&E's electric revenues. For the same reasons previously cited in the discussion of electric revenues, the Commission finds that no adjustment should be made.

LG&E's normalized gas operating revenues have been reduced by $11,289,435 to $183,296,032 based on LG&E's latest gas cost adjustment effective November 1, 1990.[28] This includes gas cost revenues of $118,995,993 based on LG&E's current cost of gas. LG&E's purchased gas expense has also been reduced to this amount to reflect the current gas cost adjustment. With this adjustment, LG&E's gas operating revenues will be properly normalized for rate-making purposes.

Fuel Cost Recovery

On an adjusted basis, LG&E's electric fuel cost exceeded its fuel cost recovery by $1,737,240 during the test year. The AG proposed an adjustment to reduce fuel expense by $1,737,240 in order to match fuel cost and fuel cost recovery to ensure that the test-year under-recovery of fuel costs did not impact the setting of base rates in a non-fuel cost rate proceeding.

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[28] Case No. 10064-J, The Notice of Purchased Gas Adjustment Filing of Louisville Gas and Electric Company, Order dated November 1, 1990.

LG&E maintains that the AG's adjustment was based on an erroneous understanding of the fuel adjustment clause ("FAC"). LG&E contends that the timing difference that exists between the incurrence of fuel costs and the recovery of fuel costs prohibits a matching of fuel cost and fuel revenues in any 12-month period. LG&E recounts that these types of adjustments have not been made in its past rate cases because the FAC was not designed to match revenues with expenses but was designed to track a variable cost outside of a general rate proceeding.

LG&E opines that the over- and under-recovery mechanism approved in Administrative Case No. 309[29] will improve the match between fuel cost and fuel revenues but will not provide for a full reconciliation of costs and that the proposed adjustment would deprive LG&E of the opportunity to fully recover its costs.

It is true that the current FAC does not produce an absolute synchronization of fuel costs and fuel cost recovery. Nor does it result in a full reconciliation of costs that will produce a precise matching of fuel costs and fuel revenues in any 12-month reporting period. The current FAC, however, with the over- and under-recovery mechanism approved in Administrative Case No. 309 is fully recovering, meaning that all allowable fuel costs will, over time, be recovered through the clause.

In the past, the FAC tracked fuel costs for one month in order to determine an adjustment factor that would be applied to a

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29 Administrative Case No. 309, An Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056, Order dated December 18, 1989 and Order dated April 16, 1990.

subsequent month's kilowatt-hour sales. This factor, applied with a 2-month lag to a different level of sales, would produce an over- or under-recovery for the billing month that was not tracked, or reconciled, in subsequent months. Once incurred, a monthly over- or under-recovery was lost, either to the utility or the ratepayer, and was not subject to true-up at a later date.

The over- and under-recovery mechanism now in place ensures that a given month's over- or under-recovery will be tracked and included in the utility's fuel cost calculation in a later month. The result is a fully recovering FAC through which all allowable fuel costs will, over time, be recovered. With recovery of fuel costs through the FAC assured, it is improper to include the over- or under-recovery of a given test year in the determination of a utility's revenue requirements. Therefore, an adjustment should be made to eliminate LG&E's test-year under-recovery of $1,737,240.

Labor and Labor-Related Costs

LG&E proposed adjustments to increase the test-year operating expenses by $3,570,447 for labor and labor-related costs. The actual cost items and the proposed adjustments to combined gas and electric operations are as follows:

	Total
Wages and Salaries	$4,010,669
FICA Taxes	334,829
Federal Unemployment	21,262
State Unemployment	41,348
Health Insurance	(636,899)
Pensions	(462,358)
Dental Insurance	29,463
Group Life Insurance	232,133
	$3,570,447

Wages and Salaries. LG&E proposed to increase wages and salaries by $4,010,669. The proposed increase reflected the effects of base wage increases granted to non-union employees during the test year, a lump sum transition payment to non-union employees during the test year, a 3 percent wage increase for union employees effective November 12, 1990, and a change in the labor capitalization rate due to the future commercialization of Trimble County. LG&E's adjustment included the annualization of the actual test-year-end levels of wages for each employee group. The November wage increase was applicable to all of LG&E's union employees, including those identified as "project temporaries" who work at Trimble County. Instead of using its test-year actual labor capitalization rate, LG&E used the capitalization rate for the month of April 1990 and adjusted it to reflect the changes expected in labor operating expenses due to the commercialization of Trimble County. This adjusted labor capitalization rate was included in all of LG&E's labor and labor-related cost adjustments.

The AG disagreed with three components of LG&E's proposed adjustment: (1) allowing the 3 percent union wage increase for the project temporaries, citing LG&E's statements that these employees would no longer be employed once Trimble County was in commercial operation; (2) the inclusion of the lump sum transition payment to non-union employees, stating that future incentive payments were not known and measurable and not appropriate for inclusion; and (3) the use of the adjusted April 1990 capitalization rate, inasmuch as LG&E had not established that

April was a representative month and that LG&E was attempting to recover Trimble County costs without making necessary adjustments to off-system sales and expenses.

KIUC recommended that all non-Trimble County pre- and post-test-year adjustments proposed by LG&E be rejected as inconsistent with the basic underlying concepts of determining the test year basis for fair, just, and reasonable rates.[30] KIUC included the November 1990 union wage increase in this group of adjustments. KIUC further argued that all pro forma adjustments proposed by LG&E be rejected in the absence of a complete set of appropriate pro forma adjustments to non-Trimble County operating income and rate base.[31]

LG&E's proposed adjustment to wages and salaries is reasonable, except for two issues. While the November union wage increase is based on the union contract, the Commission does not believe it is appropriate to allow the 3 percent increase for the Trimble County project temporaries. This particular group of employees will be terminated once Trimble County is completed.[32] The use of the adjusted April 1990 labor capitalization rate proposed by LG&E is not acceptable. The adjustment of the rate to reflect what is expected to happen when Trimble County is commercialized is not appropriate. In light of the Commission's decision to include only the level of investment in Trimble County

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30 Kollen Direct Testimony, page 25.

31 Id., page 29.

32 T.E., Volume IV, November 19, 1990, page 268 and 269.

as of test-year end, it is not appropriate to use the estimated labor capitalization rate. However, we have used the actual labor capitalization rate for the last month of the test year, April 1990, without the Trimble County adjustment. The April 1990 labor capitalization rate was 32.09 percent[33] which reduces LG&E's test-year wages and salaries by $475,505.

FICA Taxes. LG&E proposed to increase its FICA taxes to reflect increases in total wages and salaries, a change in the FICA taxable wage base, and a change in the FICA tax rate. The Commission has reviewed LG&E's calculations for the FICA taxes. It appears that LG&E did not include in its calculations the effects of the November 1990 union wage increase. Wage adjustments and payroll tax adjustments should be determined in a consistent manner and reflect the same wage increases. Based on the Commission's decisions concerning the wage and salary adjustment, the FICA taxes have been recalculated which increases LG&E's test-year FICA taxes by $133,583.

Unemployment Taxes. In calculating its proposed increase to federal and state unemployment taxes, LG&E followed the methodology outlined by the Commission in Case No. 10064. The proposed adjustment is reasonable, except for the labor capitalization rate. Using the actual April 1990 labor

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33 Response to the Commission's Order dated June 29, 1990, Item 16(d), page 7 of 16, $3,314,676 / $10,330,308 = 32.09 percent.

capitalization rate, federal unemployment insurance should be increased $14,701 and state unemployment insurance should be increased $33,850 over the test-year actual expense.

Health Insurance. LG&E's proposed reduction in health insurance costs reflected its efforts in controlling its medical benefit costs, which had been an issue in LG&E's last two general rate cases. The AG opposed the use of the adjusted April 1990 labor capitalization rate in the calculation of this adjustment. Using the actual April 1990 labor capitalization rate, it is reasonable to reduce the test-year health insurance expense by $1,003,962.

Pensions. LG&E's proposed pension expense adjustment included the results of its latest actuarial study. The AG disagreed with incorporating the results of this study in the adjustment, stating that a change in wage assumptions was not an appropriate reason to ask ratepayers to bear the additional expense. The AG also opposed the use of the adjusted labor capitalization rate. Except for the labor capitalization rate utilized, the pension adjustment is reasonable, resulting in a $566,651 decrease in test-year pension expense.

Dental Insurance. The AG again opposed the use of the adjusted labor capitalization rate in determining the adjustment to dental insurance. The Commission believes that the dental insurance expense is reasonable, except for the labor capitalization rate utilized, and has determined the test-year dental insurance expense should be decreased by $7,909.

Group Life Insurance. In determining its proposed increase to group life insurance expense, LG&E followed the methodology outlined by the Commission in Case No. 10064. Included in the calculations were the total November 1990 union wage increase and the adjusted April 1990 labor capitalization rate. For the same reasons stated concerning the wage and salary adjustment, the AG opposed the inclusion of the union wage increase for the Trimble County project temporaries and the adjusted labor capitalization rate. In accordance with our decision on the wage and salary adjustment, we have excluded the union wage increase for the project temporaries and utilized the actual April 1990 labor capitalization rate in making this adjustment, which increases the test-year group life insurance expense by $206,187.

401(k) Thrift Savings Plan. Included in LG&E's test year expenses for labor-related costs was the employer's share of its 401(k) thrift savings plan ("401(k) plan"), which totalled $449,029. This amount represented LG&E's match to amounts deferred by its non-union employees who participated in the 401(k) plan. LG&E proposed no adjustment to the test-year expense. LG&E noted that the 401(k) plan was available only to non-union employees, and very little of the matching share amount would be appropriate to capitalize.[34]

The AG proposed to reduce the test-year expense to reflect the capitalization of the expense at the test-year actual labor

34 T.E., Volume IV, November 19, 1990, pages 304 and 305.

capitalization rate, and that it was inappropriate to totally expense this item.[35]

The Commission's initial concern that LG&E had not adjusted the test-year expense to reflect the effects of its corporate reorganization, which occurred during the test year, was allayed by LG&E's schedule which showed the annualized test-year-end employer match to be $385,349.[36] We find it reasonable to include $385,349 in expenses for the 401(k) plan, which generates a reduction of $63,680 in test-year expense.

Supplemental Executive Retirement Plan. The AG proposed an adjustment removing the test-year expense of LG&E's Supplemental Executive Retirement Plan ("SERP"). The AG stated that the SERP was designated for certain key employees, and in light of the overall compensation and fringe benefits available to those employees, the costs of the SERP should not be borne by ratepayers. We agree, which reduces expenses by $247,922.

The Commission has noted in this proceeding several references by LG&E to its analysis and outside evaluations of portions of its labor and labor-related costs. In past orders the Commission has encouraged this type of evaluation, as did the management audit in several recommendations. However, LG&E has not yet performed an overall, comprehensive evaluation of its total compensation and fringe benefits package. Such an

35 DeWard Direct Testimony, page 31.

36 Responses to Data Requests from Hearing, filed December 5, 1990, Item 18.

evaluation would compare LG&E's total compensation and fringe benefits package with other utilities as well as with other industries in its general service area. LG&E should undertake such an analysis of its total compensation and fringe benefits package as soon as possible.

Amortization of Downsizing Costs

During the last quarter of 1989, LG&E undertook a corporate reorganization which resulted in a workforce reduction of 174 exempt and non-exempt employees. Throughout this proceeding, this corporate reorganization has been referred to as a "downsizing." The costs associated with this downsizing totalled $9,486,550 and were composed of separation allowance payments, enhanced early retirement benefits, post-retirement health care provisions, and a gain on the purchase of retired employees' annuities.[37] LG&E proposed to amortize these costs over a 3-year period, and pointed out that the annual amortization would not exceed the expected annual savings resulting from the downsizing.[38]

The AG stated that LG&E had incurred or accrued these costs during the test year, had expensed these items during the test year, that these costs would not be occurring on a going forward basis,[39] and recommended removing the test-year downsizing costs in total and not allow amortization.

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37 Fowler Direct Testimony, page 18.

38 Id., page 19.

39 DeWard Direct Testimony, pages 28 and 29.

KIUC recommended that the downsizing costs be amortized over a 10-year period linked to the Commission's acceptance of KIUC's proposals concerning unbilled revenues. KIUC stated that if its proposals concerning unbilled revenues was not accepted, the Commission should disallow recovery of the downsizing costs as a matter of consistency.[40]

LG&E incurred and recorded the downsizing costs in the test year. LG&E has already recovered these costs from its ratepayers. While adjustments in its workforce will occur, it is highly unlikely that LG&E will be involved with a downsizing of this magnitude on a recurring basis. We have removed the entire $9,486,550 of downsizing costs for rate-making purposes.

Storm Damage Expenses

LG&E proposed an adjustment to increase storm damage expenses by $723,291. LG&E calculated its adjustment by averaging the actual storm damage expenses for the last 5 calendar years and comparing the average to the test-year actual expense. The methodology was essentially the same as was used by the Commission in Case No. 10064.

Jefferson et al. performed an analysis of LG&E's storm damage expenses for the past 15 years and determined that the test-year expense level was not below normal. Jefferson et al. arrived at the same conclusion using the 5-year period LG&E used but substituting two abnormal years with two normal years of expenses.

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40 Kollen Direct Testimony, page 25.

As the Commission noted in Case No. 10064, the random occurrence of severe storm damage cannot be accurately predicted. The Commission finds it is appropriate to include for rate-making purposes a level of storm damage expense which reflects a reasonable, on-going level of expense. Traditionally, the Commission has used historic averages in determining this reasonable level of expense. In this proceeding, the Commission has available the actual storm damage expenses for the past 15 calendar years. However, simply taking the average of an historic period would not recognize the effects of inflation when looking at such a long period of time. In Case No. 90-041[41] the Commission computed storm damage expenses by taking a 10-year average of actual expenses, adjusted for inflation by using the Consumer Price Index - Urban. We feel this approach the more reasonable and the preferred methodology to be used in determining this adjustment, which results in a $520,533 increase in storm damage expenses.

Provision for Uncollectible Accounts

LG&E proposed an increase of $100,000 to the test-year level of uncollectible accounts expense based on its analysis of the appropriate total annual provision. The proposed increase was determined using LG&E's actual 1990 accrual rate for the provision.

41 Case No. 90-041, An Adjustment of Gas and Electric Rates of the Union Light, Heat and Power Company, Order dated October 2, 1990.

Jefferson et al. opposed the increase to the expense, citing the fact that LG&E's actual charge-off history and accruals for uncollectible accounts over the past 5 years have experienced significant decreases in overall percentage.

The Commission believes it is best to leave the uncollectible accounts expense at the test-year level.

Location of Gas Service Lines

LG&E proposed an increase of $152,000 in expenses related to the location of customer owned service lines on private property. LG&E stated that this adjustment reflects the additional costs that it expects to incur as a result of placing temporary markings to locate customer service lines.[42] The Commission finds that LG&E has not adequately explained or supported the necessity for this proposed adjustment. Therefore, the Commission has not included the proposed increase in expense. The Commission is not attempting to limit this activity. However, in determining the reasonable level of expense on an on-going basis, consideration must be given to whether the activity involves an item which should be expensed or capitalized. LG&E did not provide specific evidence to allow a thorough analysis of this issue.

Headwater Benefit Assessment

LG&E proposed an increase of $108,033 in expenses to reflect the first year of a 3-year amortization of its Federal Energy Regulatory Commission ("FERC") headwater benefit assessment. The total amount of $324,098 reflects LG&E's initial FERC payment

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42 Fowler Direct Testimony, page 21.

pending LG&E challenges to FERC's original assessment of $3,600,000. LG&E recorded this payment as a deferred debit.

KIUC claimed that LG&E had no regulatory authority to defer this cost for future recovery. KIUC further stated that LG&E selectively identified this cost as recoverable since it was not specifically identified as an expense in its last rate case. Under established rate-making theory, LG&E must bear the risks and rewards of such costs as long as specific regulatory authority for differing treatment is absent. KIUC argues that by allowing this adjustment, the Commission would establish a precedential basis for future manipulation of actual earnings and improper increases in revenue requirements in future rate cases.

Given that LG&E has not heretofore recovered this payment from its ratepayers, we find it reasonable to allow LG&E to amortize the headwater benefit assessment over a 3-year period.

Depreciation and Amortization Expense

LG&E proposed to increase depreciation expense by $15,333,843 in order to annualize the test-year-end level of expense and to reflect the first year of depreciation expense on Trimble County. Of the total adjustment, $15,171,389 was for electric and $162,454 was for gas. Included in the annualization calculations were the effects of LG&E's recently completed depreciation studies of the electric and gas plant in service. The increase in the electric depreciation reflected first year depreciation expense based on estimated total cost of $715,000,000 adjusted for the 25 percent disallowance.

The AG, KIUC, and Jefferson et al. all opposed this inclusion stating that LG&E wanted to treat Trimble County in a vacuum,[43] that LG&E's proposed treatment lacked consistency,[44] and that LG&E's adjustment for Trimble County expenses did not meet the known and measurable standard.[45]

Although the first year depreciation expense based on the CWIP as of April 30, 1990 is allowed, supra, we do not include any depreciation expense on the additional expenditures incurred after test-year-end. This allowance, together with other components of LG&E's proposed adjustment we find reasonable and should be included in expenses, which results in increased depreciation and amortization expenses of $14,431,836, $14,269,382 electric and $162,454 gas.

Property Taxes

LG&E proposed to increase its property tax expense by $982,754 based on the 75 percent recoverable portion of the total expected expenditures for Trimble County estimated at $715,000,000.

The AG, KIUC, and Jefferson et al. opposed the proposed adjustment for the same reasons they expressed concerning the Trimble County depreciation adjustment.

Consistent with our other decisions relating to Trimble County, we have included a portion of the fixed costs of Trimble

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43 DeWard Direct Testimony, page 48.

44 Kollen Direct Testimony, page 19.

45 Kinloch Direct Testimony, page 11.

County to allow an increase in property taxes related to the balance of Trimble County CWIP as of April 30, 1990, which increases the test-year property tax expense by $931,857.[46]

EPRI Membership Dues

LG&E proposed an increase of $1,311,826 to expenses representing the projected 3-year average of the annual membership dues LG&E will pay the Electric Power Research Institute ("EPRI"). In order for LG&E to access the research and development programs and materials produced by EPRI, LG&E became a member of EPRI in July 1990. LG&E's evidence showed that the annual costs of its membership in EPRI would be offset by the benefits it receives from EPRI. The full membership dues are phased-in over a 3-year period, and LG&E's proposed adjustment reflects the average of those first 3 years' dues as calculated for 1990.

The AG opposed the proposed adjustment because LG&E had not quantified any cost savings attributable to its membership in EPRI. KIUC opposed the adjustment because LG&E had not proposed all appropriate pro forma adjustments. Jefferson et al. recommended the Commission withhold ratepayer support of EPRI until EPRI's restrictive membership policy is changed or, at a minimum, the Commission should exclude that portion of EPRI's dues relating to nuclear research.

LG&E should have quantified expected cost savings and included those offsetting savings. The payment of the membership dues was clearly a post-test year transaction and the benefits

[46] Fowler Direct Testimony, Exhibit 1, Schedule E, line 3.

will likewise be reflected in reductions of future costs. In order to properly include the dues in this case, the cost savings expected from membership should have also been included. Because these expected savings were not shown, we feel compelled to exclude this proposed increase in expenses. The Commission realizes that utilities need to undertake research and development projects, and we are not opposed to including the costs of those projects when they are determined to be reasonable and benefits are demonstrated and factored into the proposed revenues and expenses.

EEI Membership Dues

During the test year, LG&E recorded as operating expense membership dues of $178,779 to the Edison Electric Institute ("EEI"). In Case No. 10064, the Commission excluded the membership dues to EEI because LG&E had failed to show that its membership in EEI was of direct benefit to its ratepayers.[47] The AG proposed to reduce the test year expense for various EEI-related activities it considered inappropriate. Jefferson et al. proposed that all EEI dues be removed from the test year because EEI was a utility industry lobbying organization. Although LG&E gave three examples of ratepayer benefits derived from its membership in EEI, it still has not adequately shown that there is a direct ratepayer benefit from membership in EEI. As LG&E acknowledged, all of the major benefits associated with EEI

[47] Case No. 10064, final Order dated July 1, 1988, page 60.

membership are available to LG&E independent of EEI. Further, EEI's lobbying activities are clearly a below-the-line expense.

New Office Expenses

In keeping with LG&E's position to exclude all costs associated with the relocation to the new corporate headquarters, an additional $2,489[48] in legal costs related to the headquarters relocation which were inadvertently included in the test year have been excluded.

Holding Company Expenses

In keeping with the Commission's Order in Case No. 89-374,[49] $6,612[50] in legal expenses incurred for the LG&E Energy Corporation ("Holding Company") included in test-year operating expenses has been disallowed.

Trimble County Marketing Costs

Test-year costs of $156,434[51] associated with marketing the 25 percent disallowed portion of Trimble County has been excluded, decreasing operating expenses by $156,323. The AG had proposed to remove $500,000 in Trimble County expenses, but produced no evidence to support his assumptions.

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48 Responses to Data Requests from Hearing, filed December 5, 1990, Item 9.

49 Case No. 89-374, Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith, Order dated May 25, 1990.

50 Responses to Data Requests from Hearing, filed December 5, 1990, Item 8.

51 LG&E Hearing Exhibit No. 16.

State Sales Taxes

LG&E proposed to increase its state sales tax expense by $163,000 to reflect the change in the Kentucky sales taxes rate effective July 1, 1990. Although KIUC opposed this adjustment on the grounds that LG&E had not made necessary the pro forma adjustments, The Commission believes it is reasonable to reflect this change in the state sales tax rate and has increased the state sales tax expense by $163,000.

Office Supplies and Professional Services Expenses

The AG proposed to reduce LG&E's test-year expenses for office supplies and professional services by $1,818,791. This amount represented a reduction to the levels recorded in the year prior to the test year. The AG argued that LG&E had failed to meet its burden of proof in justifying these expense increases, and advocated the Commission further decrease LG&E's test-year expenses to reflect information provided subsequent to the hearing as well as improper items of expense included by LG&E but not detected by the AG.[52]

The Commission has reviewed the account description in the Uniform System of Accounts ("USoA") for Account No. 921, Office Supplies and Expenses. This account can include charges for items such as printing, stationary, meals, traveling, and incidental expenses. However, expenses charged to any account must be evaluated on the reasonableness of the charge and how appropriate it is to include the charge for rate-making purposes. The charges

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52 Brief of AG, page 1.

questioned by the AG were recorded in subaccounts of Account No. 921 which were periodically "zeroed out." Thus, these charges were not included in the test-year balance for Account No. 921. Given the information available, the Commission finds reasonable the test-year level of expense recorded in Account No. 921.

Concerning the professional services, LG&E has shown that it had already removed or reduced several of these charges in its pro forma adjustments. The Commission has specifically reviewed the invoices provided to the AG for test-year legal charges. LG&E edited many of these invoices and provided only very brief descriptions for the edited items. LG&E claimed that it could not disclose the nature of certain legal activities under the attorney-client privilege. The invoices included charges for numerous proceedings involving Trimble County and other major issues before or with the Commission. The Commission believes it is reasonable to remove the charges for the numerous Commission related proceedings since this level of activity should not be as large with the completion of Trimble County, on a going forward basis. We have also removed charges relating to the invoices where descriptions have been omitted, reducing test-year professional services expense by $294,676.

Miscellaneous Expense Adjustments

The AG proposed to reduce miscellaneous expenses by $314,903. Included in this proposed adjustment were contributions, economic development donations, moving expenses, and commitment fees recorded above the line, which the AG argues were not the ratepayers responsibility. The AG also argued that LG&E's

commitment fees should not be as high as in the past, since these fees had been related to the financing needs of Trimble County.

We have removed the contributions, economic development donations, and the moving expenses from the test-year expenses. The Commission traditionally has excluded above the line contributions and donations from rates; and we have not been persuaded that the moving expenses incurred in the test year represent a recurring item of expense. However, it is reasonable to include the test year level of commitment fees, because LG&E will be incurring commitment fees for its financing requirements on a recurring basis. Taken together this reduces test-year miscellaneous expenses by $151,507.

Amortization of Management Audit Fee

In Case No. 10064, the Commission approved LG&E's request to amortize the cost of the Management Audit over a 3-year period. This resulted in an annual amortization of $194,000.[53] As of the end of the test year, $226,333[54] remained to be amortized. At the present amortization rate, LG&E would have recovered the cost by the middle of 1991.

LG&E should recover the total cost of the management audit but it is not entitled to recover in excess of its cost, requiring the amortization rate to now be adjusted. The annual amortization rate for rate-making purposes should be $75,444 based on a 3-year amortization of the unamortized cost at test-year-end.

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53 Case No. 10064, Order dated July 1, 1988, page 62.

54 April 1990 Monthly Report, page 28.

Considering that the amortization has continued during the course of these proceedings, LG&E will recover its entire cost by the middle of 1992 at the $75,444 annual amortization rate. Test-year expenses have been reduced by $118,560 to reflect this adjustment.

Annualization of Year-End Customers

LG&E proposed an increase in operating expenses of $1,118,728 to reflect the increase in expenses related to annualizing the number of customers at test-year-end. This adjustment corresponded to a similar adjustment to operating revenues.

The AG proposed an increase in operating expenses of $947,065. The AG made several adjustments to the operating expenses used in the calculation of the proposal, stating that several expenses included by LG&E had not been shown to vary with the number of customers. The AG further stated that absent an LG&E study which showed that expenses increased with customer growth revenues, any adjustment based on an operating ratio is not known and measurable.[55]

The Commission specifically used the operating ratio methodology in Case No. 10064 and LG&E has followed that methodology in preparing its proposal. We have accepted LG&E's proposed adjustment.

Directors and Officers Liability Insurance

The AG proposed to reduce expenses by $245,943 to reflect the assignment of 50 percent of the cost of directors and officers liability insurance to the shareholders of LG&E. The AG argued

55 DeWard Direct Testimony, page 33.

that the protection provided by the insurance was for both the shareholder and ratepayer. While there may be some benefits to shareholders, the main beneficiaries are the ratepayers. This insurance allows LG&E to induce highly qualified individuals to serve on its Board of Directors. We feel it is not proper or reasonable to include this adjustment.

Workers' Compensation Insurance

The AG proposed to reduce expenses by $536,187 to reflect a portion of the Workers' Compensation insurance expense recorded in the test year as capitalized. The AG stated that it was unclear whether LG&E was capitalizing any of the Workers' Compensation insurance costs, but that such an adjustment was appropriate. LG&E indicated that it was in fact capitalizing its Workers' Compensation insurance costs.[56] The Commission believes the amount included as workers' compensation insurance expense is reasonable.

Amortization of Investment Tax Credits

LG&E proposed to increase the amortization of investment tax credits ("ITC") by $1,554,000. The proposal reflected the change in depreciation rates used by LG&E and the amortization of ITCs attributable to Trimble County. The proposal reflected Trimble County ITCs for plant to be in service as of December 31, 1990.

The AG, KIUC, and Jefferson et al. opposed the inclusion of the Trimble County ITC amortization for the same reasons expressed

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56 T.E., Volume IV, November 19, 1990, page 185.

concerning LG&E's proposed adjustment to depreciation expense related to Trimble County.

As discussed earlier in this Order, it is reasonable to nclude Trimble County CWIP as of test-year end and the related first year depreciation expense in rates. Likewise, it is reasonable to include the amortization on the Trimble County ITCs related to the April 30, 1990 balance of CWIP, which increases the amortization of ITCs by $1,507,000.[57]

Flowback of Unprotected Federal Excess Deferred Taxes

In Case No. 10064, the Commission ordered LG&E to amortize $4,749,500 in unprotected federal excess deferred taxes and $4,385,600 in state tax deficiencies over a 5-year period.[58] The AG claimed that LG&E did not appear to be in conformity with the Order in Case No. 10064 and proposed that the test year flowback of the unprotected federal excess deferred taxes be increased by $162,300. LG&E stated that it had changed the amount of the federal amortization due to the discovery of some errors in the amounts originally provided to the Commission in Case No. 10064, but even after the discovery of these errors, it had not informed the Commission of the change. LG&E filed information concerning the change in the amount of unprotected excess deferred taxes and its change in the amortization amount.

The Commission has reviewed the account information. It appears that both amortization amounts have been changed, not just

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57 Fowler Direct Testimony, Exhibit 1, Schedule Y, line 5.

58 Case No. 10064, Order dated July 1, 1988, page 61.

the amortization for the federal excess deferred taxes. Insufficient information has been provided to justify a change in the federal amortization as ordered in Case No. 10064. The flowback of unprotected federal excess deferred taxes is restored to the level ordered in Case No. 10064 by $162,300.

State Income Tax Rate Change

LG&E proposed three adjustments to reflect the change in the Kentucky income tax rate, which became effective January 1, 1990. The adjustments were an increase in state income tax of $508,000; an increase in deferred state income tax of $42,000; and an increase in the amortization of cumulative state deferred tax of $512,000. In all three adjustments, LG&E computed the corresponding savings in federal income taxes relating to the state income tax rate change.

The methodology used to reflect the change in the state income tax rates is reasonable. But, based on the information provided, these adjustments require recalculations to reflect the level of state tax deficiency identified in Case No. 10064. The state income tax is increased by $508,000; deferred state income tax increased by $41,473; and the amortization of cumulative state deferred tax increased by $446,582.

Tax Adjustment for Other Interest Expense

LG&E proposed to increase income tax expense by $198,430 to reflect the income taxes applicable to other interest expense. In Case No. 10064, the Commission determined that LG&E could not recover other interest expense from ratepayers. Because LG&E could not recover this expense from ratepayers, LG&E claims that the ratepayers should not receive any corresponding income tax benefits. We do not agree. According to the USoA, other interest expense is recorded below the line.

It is not proper to make the proposed adjustment to income tax expense without supporting documentation which shows LG&E included other interest expense in the determination of its above-the-line income tax expense.

Interest Synchronization

LG&E proposed two adjustments in order to determine its interest synchronization. The first adjustment annualized the interest expense on debt, and the second reflected the allocation of JDIC on the computation. Traditionally, the Commission has applied the cost rates applicable to the long-term debt and short-term debt components of the capital structure in order to compute an interest adjustment. This was the approach the Commission used in Case No. 10064. The debt components utilized in this computation reflect the effects of the JDIC allocation and reductions to capital structure due to the 25 percent Trimble County disallowance and the capital costs of LG&E's new office building. Using the adjusted capital structure allowed, the Commission has computed an interest reduction of $1,193,023 which results in an increase to income taxes of $470,588.

Following the approach used in Case No. 10064, the Commission has applied the combined state and federal income tax rate of 39.445 percent to the accepted pro forma adjustments. The Commission finds that combined operating income should be increased by $6,639,060 to $130,376,955.

The adjusted net operating income is as follows:

	Electric	Gas	Total
Operating Revenues	$502,388,881	$183,296,032	$685,684,913
Operating Expenses	384,835,893	170,472,065	555,307,958
ADJUSTED NET OPERATING INCOME	$117,552,988	$ 12,823,967	$130,376,955

RATE OF RETURN

Capital Structure

LG&E proposed an adjusted end-of-test-year capital structure containing 43.13 percent long-term debt, 4.69 percent short-term debt, 8.22 percent preferred stock, and 43.96 percent common equity. Year-end, long-term debt was adjusted to reflect: (1) the retirement of $16,000,000 of 4 7/8 percent First Mortgage Bonds, Series due October 1, 1990;[59] (2) the scheduled redemption of $750,000 of 1975 Pollution Control Bonds due September 1, 1990;[60] and (3) the refinancing of $25,000,000 of Series J 1985 Pollution Control Bonds at 8.25 percent interest with 1990 bonds at 7.45 percent interest.[61] The retirement of the $16,000,000 of 4 7/8 percent First Mortgage Bonds and the redemption of the $750,000 1975 Pollution Control Bonds were reflected as adjustments to short-term debt. The refinancing of the 1985

59 Fowler Direct Testimony, Exhibit I, Schedule V.

60 Id.

61 T.E., Volume IV, November 19, 1990, page 11.

Series J Pollution Control Bonds with 1990 bonds did not affect the capital structure.

LG&E decreased year-end preferred stock and increased common equity by $1,033,459, the discount and expense associated with the preferred stock issues.[62] LG&E also decreased common equity by $9,251,593 to reflect the adjustment to retained earnings for unbilled revenues as discussed previously in this Order.[63]

The AG proposed a capital structure containing 43.11 percent long-term debt, 4.69 percent short-term debt, 8.30 percent preferred stock, and 43.90 percent common equity.[64] The difference in the AG's proposal and LG&E's proposal is that the AG proposed to exclude unamortized premiums, discounts, and expenses. The AG claims these amounts are not a part of the permanent financing of a utility. Moreover, the AG disagreed with LG&E's adjustment to place the preferred stock discount and expense in the weighted average of preferred stock.[65] The AG maintained that the preferred stock discount and expense was properly recorded in the capital stock account and should remain in the weighted average of common equity.

Premiums, discounts, and other expenses of issuing securities are an integral part of the financing of a utility and should be

62 Fowler Direct Testimony, page 1 of 2.

63 Id., page 1.

64 Weaver Direct Testimony, Exhibit, Statement 17.

65 Id., page 30.

reflected as such in the capital structure. LG&E's adjustment to place the discount and expenses associated with preferred stock in the preferred stock structure is appropriate. The Commission finds LG&E's capital structure is as follows:

	Percent
Long-Term Debt	43.13
Short-Term Debt	4.69
Preferred Stock	8.22
Common Equity	43.96
Total Capital	100.00%

Cost of Debt and Preferred Stock

LG&E proposed a cost of long-term debt of 7.72 percent after adjustments for the refinancing of the $25,000,000 1985 First Mortgage Bonds.[66] The AG proposed a cost of long-term debt of 7.79 percent[67] but did not include an adjustment for refinancing the 1985 First Mortgage Bonds. To arrive at its cost of long-term debt, LG&E included the unamortized premium on bonds in long-term debt and adjusted interest expense by the amortization of expenses, premiums, and the loss on reacquired debt.[68] The AG did not include the unamortized premium on bonds in long-term debt and adjusted interest expense by the amortization of the expenses and

66 Calculated from Fowler Direct Testimony, Exhibit 2, page 1; and T.E., Volume IV, November 19, 1990, page 11.

67 Weaver Response to LG&E, 17.

68 Fowler Direct Testimony, Exhibit 2, page 1; and Exhibit 1, Schedule V.

premium but did not adjust interest expense by the amortization of the loss on reacquired debt.[69]

It is more appropriate to adjust long-term debt by the unamortized premium on bonds and to adjust interest expense by the amortization of the loss on reacquired debt. We find the cost of long-term debt to be 7.72 percent.

LG&E proposed the cost of short-term debt to be 8.38.[70] The AG proposed the cost of short-term debt to be 8.43.[71] The AG subsequently agreed with a cost of 8.38, and the Commission concurs.

LG&E[72] and the AG[73] both agreed that the cost of preferred stock is 8.09 percent and the Commission concurs.

Return on Equity

LG&E proposed a return on equity ("ROE") in the range of 13.0 to 13.5 percent,[74] and subsequently revised its expected cost of equity to be in the range of 13.25 to 13.75 percent.[75] The AG proposed a range of 12.0 to 12.5 percent.[76] KIUC proposed an ROE

69 Weaver Direct Testimony, Exhibit, Statement 15.

70 Fowler Direct Testimony, Exhibit 2, page 1.

71 Weaver Direct Testimony, Exhibit Statement 16, page 2.

72 Fowler Direct Testimony, Exhibit 2, page 1.

73 Weaver Direct Testimony, Exhibit, Statement 17.

74 Olson Direct Testimony, page 36.

75 Olson Supplemental Testimony, page 18.

76 Weaver Direct Testimony, page 28.

of 11.7 percent.[77] Jefferson et al. proposed an ROE in the range of 11.0 to 11.5 percent.[78]

To determine the ROE, LG&E used a discounted cash flow ("DCF") analysis. In addition, LG&E utilized an interest premium calculation and DCF study of eight other electric utilities as a check on the results of its DCF analysis. LG&E adjusted the results for financing costs and to show additional margin.

In its DCF analysis, LG&E used a dividend yield of 7.57 percent[79] based on a projected dividend rate of $2.84 and a 6-month high/low stock price average during the period May 1 - October 26, 1990.[80] LG&E relied on three methods of analysis to determine its estimated growth rate: 1) a study of past and current trends in dividends, earnings and book value; 2) retention or internal growth; and 3) estimates of expected growth available from security analysts.[81] Based on its analysis, LG&E opined that investors expect growth of 4.75 to 5.25 percent.[82] Overall, LG&E's DCF analysis produced a return requirement of 12.32 to 12.82 percent.[83]

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77 Baudino Direct Testimony, page 26.

78 Kinloch Direct Testimony, page 22.

79 Olson Supplemental Testimony, page 17.

80 Id.

81 Olson Direct Testimony, page 23.

82 Id., page 29.

83 Olson Supplemental Testimony, page 17.

Using an interest premium approach as a first check on its DCF analysis, LG&E concluded its cost of common equity to be 14.5 percent. The risk premium of investors was estimated to be 4.75 percent. This was added to the current yield to maturity on Double A bonds of 9.8 percent.[84] As a second check of its results, LG&E performed a DCF study of eight selected utilities. The results indicated an investor requirement of 12.48 to 12.98 percent.[85]

LG&E determined that the results of its DCF analysis were not in fact the returns required by investors. LG&E applied an 8 percent premium to its DCF results to compensate for financing cost and market pressure.[86] LG&E concluded that its required ROE should be 13.25 to 13.75 percent.[87]

To perform a DCF analysis, the AG selected 5 companies he considered to be of comparable risk to LG&E. The companies considered were combination gas and electric companies reported in Value Line with characteristics similar to LG&E in capital structure ratios, total assets, fuel mix, electric vs. gas revenue distribution, betas, stock ratings, and bond ratings.[88] According to the AG's analysis, LG&E has a slightly greater amount of risk from its capital structure and operating leverage than the

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84 Olson Direct Testimony, pages 32-33.

85 Olson Supplemental Testimony, page 18.

86 Olson Direct Testimony, page 36.

87 Olson Supplemental Testimony, page 18.

88 Weaver Direct Testimony, page 6.

comparison group but this risk is offset by the greater risk of the comparison group from acid rain legislation.[89]

The AG used four methods of calculating growth for its DCF analysis. The methods used were: 1) compound growth rate in dividends per share; 2) compound growth rate in earnings per share; 3) compound growth rate in book value per share; and 4) earnings retention ratio multiplied by ROE. Based on these calculations, the AG's recommended growth rate was 4.0 to 4.5 percent.[90]

The AG calculated a dividend yield from June 29, 1990 through September 7, 1990 of 7.44 percent for LG&E and 7.75 percent for the comparison group.[91] The AG employed these yields in its DCF analysis to reflect greater uncertainty caused by the Middle East situation.[92] The results of the AG's DCF analysis yielded an ROE for LG&E of 11.74 to 12.27 percent and 12.06 to 12.60 percent for the comparable companies.[93] Based on these results the AG determined LG&E's required ROE to be within a range of 12.0 to 12.5 percent.[94]

KIUC performed a DCF analysis using the same eight companies that LG&E used in its DCF study of comparable companies and a risk

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89 Id., page 18.

90 Id., page 25.

91 Id., page 26.

92 Id.

93 Id., page 27.

94 Id., page 28.

premium analysis. KIUC calculated a 6-month average dividend yield during the period from February through July 1990 of 7.22 percent for the comparison group[95] and 7.28 percent for LG&E.[96] Averaging the Institutional Brokers Estimate System ("IBES") earnings growth project, Value Line compound dividend growth rate from 1990 to 1994, and Value Line compound earnings per share growth rate from 1990 to 1994 resulted in an expected growth rate of 4.28 percent for the comparison group[97] and 3.46 percent for LG&E.[98] To complete the DCF equations, KIUC applied one-half the growth rate to the historical dividend yields to arrive at a ROE for the comparison group of 11.65 percent[99] and 10.87 percent for LG&E.[100] KIUC opined that its DCF cost of equity for LG&E was too conservative given the DCF cost of equity for the comparison group.[101] KIUC found the comparison group results were not understated based on a sustainable growth calculation it performed as a check.[102]

In addition, KIUC performed a risk premium analysis as a supplementary check on its DCF analysis. Adding a risk premium of

95 Baudino Direct Testimony, page 11.

96 Id., page 18.

97 Id., page 13.

98 Id., page 19.

99 Id., page 16.

100 Id., page 20.

101 Id., page 21.

102 Id., page 25.

2.11 percent to the 9.65 percent average yield of LG&E's first mortgage bonds for February and July 1990 resulted in a cost of equity for LG&E of 11.76 percent.[103] In its final analysis, KIUC averaged the results of its DCF for comparison companies and its risk premium analysis to arrive at its estimate of 11.7 percent as a fair rate of return for LG&E.[104]

Jefferson et al. opined that an ROE between 11.0 and 11.5 percent would offer LG&E's shareholders a fair return on their investment.[105] This was based on a review of returns recently granted by other Commissions as published in Public Utilities Fortnightly and KIUC's assessment of LG&E's level of risk as compared to the named utilities.

The 8 percent premium proposed by LG&E to adjust for flotation cost and market pressure would overstate LG&E's cost of capital. LG&E is rated a solid Aa/AA by Moody's and Standard and Poor and thus can be considered less risky than the average utility investment. Pressure to finance ongoing construction is declining and by its own admission, LG&E is in a one-of-a-kind position to perform under the Clean Air Act. However, the current state of the economy is timorous. The Commission, having considered all of the evidence, including current economic conditions, finds that an ROE of 12.25 to 12.75 percent is fair, just, and reasonable. An ROE in this range would allow LG&E to

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103 Id., page 24.

104 Id., page 26.

105 Kinloch Direct Testimony, page 22.

attract capital at a reasonable cost and maintain its financial integrity to ensure continued service and provide for necessary expansion to meet future requirements, and also result in the lowest possible cost to ratepayers. A return of 12.5 percent will best meet the above objectives.

Rate of Return Summary

Applying the rates of 7.79 percent for debt, 8.09 percent for preferred stock, and 12.50 percent for common equity to the capital structure produces an overall cost of capital of 9.89 percent, which we find to be fair, just, and reasonable. This cost of capital produces a rate of return on LG&E's net original cost rate base of 9.52 percent which the Commission finds is fair, just, and reasonable.

REVENUE REQUIREMENTS

The Commission has determined that LG&E needs additional annual operating income of $3,618,915 to produce a rate of return of 12.50 percent on common equity based on the adjusted historical test year. After the provision for state and federal taxes, there is an overall revenue deficiency of $5,976,245 the amount of additional revenue granted. The net operating income necessary to allow LG&E the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $133,995,870. A breakdown between electric and gas operations of the required operating income and the increase in revenue allowed is as follows:

	Electric	Gas	Total
Net Operating Income Found Reasonable	$120,854,300	$ 13,141,570	$133,995,870
Adjusted Net Operating Income	117,552,988	12,823,967	130,376,955
Net Operating Income Deficiency	3,301,312	317,603	3,618,915
Gross Up Revenue Factor for Taxes [1.00-.39445]	.60555	.60555	.60555
Additional Revenue Required	5,451,758	524,487	5,976,245

The additional revenue granted will provide a rate of return on the net original cost rate base of 9.52 percent and an overall return on total capitalization of 9.89 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $691,661,158. These operating revenues include $507,840,639 in electric revenues and $183,820,519 in gas revenues. The gas operating revenues reflect the most recent gas cost adjustment approved in Case No. 10064-J.

PRICING AND TARIFF ISSUES

Electric Cost-of-Service Study

LG&E presented a fully embedded time-differentiated electric cost-of-service study for the purpose of allocating costs among the classes of service on the basis of cost incurrence. The study used a base-intermediate-peak ("BIP") method to allocate production and transmission costs to costing periods and to customer classes. The BIP methodology, which was approved by the

Commission in Case Nos. 8616,[106] 8924,[107] and 10064,[108] was described by LG&E in the following manner:

> The cost assignments to the base period were established on the basis of the relationship of the minimum demand to the maximum demand. This recognized that some level of capacity is always present to meet customer needs. Base costs were allocated among classes based on their individual contribution to the average system demand. Intermediate peak costs were determined on the basis of the maximum winter peak demand over and above the average demand. Such costs were then assigned to the winter peak period based on the relationship of the number of hours in that period to the total hours in both the winter and summer peak periods. Costs were then allocated among customer classes according to each class's contribution to the winter peak demand. The remaining production and transmission costs were assigned to the summer peak period and allocated on the basis of each class's contribution to the summer peak demand.[109]

All other electric cost-of-service methodologies used by LG&E are essentially the same as those approved by the Commission in LG&E's last two rate cases.

KIUC recommended that demand-related costs be allocated to customer classes using the Probability of Peak ("POP") method. This method represents a type of coincident peak allocation in which each class's contribution to the utility's twelve monthly

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106 Case No. 8616, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, Order dated March 2, 1983, pages 33-34.

107 Case No. 8924, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, Order dated May 16, 1984, pages 37-38.

108 Case No. 10064, Order dated July 1, 1988, pages 81-84.

109 Walker Direct Testimony, pages 11-12.

system peaks are weighted by a given month's relative probability of attaining the annual system peak.[110] KIUC concluded that LG&E's electric cost-of-service study could not be used because it does not properly assign costs to customer classes. KIUC argued that the BIP method is deficient because it allocates a portion of demand-related production and transmission costs on an energy basis and assigns too much of the remaining weight to LG&E's winter system peak.[111]

According to LG&E, the POP method proposed by KIUC results in an assignment of nearly 90 percent of the weight of production and transmission costs to the coincident peaks that occurred during the summer months of July and August, with over 97 percent assigned to the June-September period.[112] LG&E further contended that the POP method leads directly to a class allocation in which the lighting schedules, Rates PSL, OL, and SLE, are assigned no portion of the production and transmission demand-related costs even though customers served under those rate schedules have access to power whenever they desire it.[113] KIUC even stated that "demand-related fixed costs are incurred due to the utility's obligation to provide service when requested".[114] LG&E stated that the BIP method is superior to the POP method in reflecting

[110] Kalcic Direct Testimony, page 11.

[111] Id., page 10.

[112] Brief of LG&E, page 122.

[113] Id., pages 122-123.

[114] Kalcic Direct Testimony, page 8.

the realities of cost incurrence on its system and should be used in the analysis of cost of service.[115]

The Commission continues to believe that the BIP method is appropriate as a means of allocating production and transmission costs to the customer classes. The BIP method recognizes that LG&E's embedded production and transmission costs were incurred to meet all customer demand, not just that which is coincident with system peak. KIUC's proposed POP method places too much weight on coincident peak demand. If any customer has access to electricity whenever it is demanded, that customer should bear the responsibility of some portion of demand-related costs.

LG&E's electric cost-of-service study is acceptable and should be used as a starting point for electric rate design.

Gas Cost-of-Service Study

LG&E filed a fully embedded gas cost-of-service study to allocate costs among the classes of service on the basis of cost incurrence and to determine the relative contribution that each rate class makes to overall return on net rate base. Pursuant to a Commission directive in Case No. 10064, LG&E disaggregated its customers in this cost-of-service study into the following classes: Residential Rate G-1, Commercial Rate G-1, Industrial Rate G-1, Commercial Rate G-6, Industrial Rate G-6, and Fort Knox

115 Brief of LG&E, page 123.

Special Contract.[116] For purposes of this study, LG&E combined the sole customer served under Uncommitted Gas Service Rate G-7 with Industrial Rate G-6.[117] LG&E stated, however, that the provision of service to Rate G-7 customers is markedly different from that provided to Rate G-6 customers.[118]

LG&E did not disaggregate the customer classes further into transportation and sales categories. LG&E contended that since all transportation customers may purchase any portion of their annual gas requirements under the applicable sales rate schedules, and since all but one of its transportation customers purchased sales gas during the test year, a disaggregation of transportation customers would be unnecessary.[119]

LG&E's cost-of-service model consists of the following steps: (1) costs are assigned to the major functional groups (underground storage, transmission, distribution general, distribution structures, distribution mains, distribution services, distribution meters, customer accounting, and customer services); (2) functionalized costs are then classified into demand, commodity, and customer components; and then (3) classified costs

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116 In the Commission's Order in Case No. 10064 dated July 1, 1988, at page 81, LG&E was directed to address, in its next rate case, an assertion made by KIUC that LG&E's cost-of-service study did not fully disaggregate its various classes of customers.

117 Walker Exhibit 2, page 1.

118 Id.

119 Brief of LG&E, page 125.

are allocated to LG&E's rate classes.[120] LG&E's gas cost-of-service methodologies are consistent with those approved by the Commission in Case No. 10064.

The AG criticized several allocation methodologies used by LG&E and suggested alternative allocation factors. The AG, however, did not conduct a cost-of-service study incorporating his recommended allocation factors.[121]

The AG proposed to allocate exactly half of the demand-related underground storage and transmission costs on the basis of extreme winter seasonal requirements and design-day demand, the same factor LG&E used to allocate all of the storage and transmission demand costs in its cost-of-service study. The AG recommended that the other half be allocated on the basis of total class usage.[122]

Similarly, the AG proposed to allocate half of the commodity-related storage and transmission costs on the basis of design-day demand, with the other half allocated on the basis of total class usage.[123]

The AG proposed to allocate one-third of the costs associated with distribution structures and equipment on the basis of class

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[120] Walker Exhibit 2, page 2.

[121] T.E., Volume VII, November 26, 1990, pages 12-13.

[122] Sheehan Direct Testimony, pages 10-11.

[123] Id., page 12.

design-day demand, with the remaining two-thirds allocated on the basis of total class usage.[124]

Finally, the AG recommended substituting a usage-based allocator or a different customer-based allocator for LG&E's customer-based allocator for the allocation of costs associated with customer accounting and customer service expenses.[125]

The AG has provided no evidence to support the reasonableness of his cost-of-service allocation methodologies. In fact, when asked to explain the basis for one of his proposed methodologies, the AG's witness vaguely characterized it as "rule of thumb" and "reasonable at a first glance."[126] He also indicated that some of his other recommended methodologies could be similarly described.[127] Explanations such as that hardly support the reasonableness of the AG's recommended allocation methodologies. Furthermore, the AG is unable to quantify the effect his recommendations will have on class rates of return.[128] Considering the lack of support for the AG's recommendations, the Commission is unable to adopt them as alternatives to LG&E's allocation methodologies.

KIUC criticized LG&E's gas cost-of-service study because it does not establish separate classes for transportation customers

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124 Id., page 14.

125 Id., pages 16-19.

126 T.E., Volume VII, November 26, 1990, page 54.

127 Id., pages 55-56.

128 Id., page 58.

and sales customers. It contended this absence renders the study useless with respect to the design of cost-based transportation rates.[129]

KIUC asserted that the cost incurrence characteristics of transportation service are significantly different from those of sales service based on an analysis of load factor and customer size data for G-1 and G-6 sales and transportation customers. KIUC contended that the larger load factors and customer sizes of transportation customers indicate "radically different" cost incurrence,[130] and asserted that the gas cost-of-service study should disaggregate transportation customers from sales customers.

KIUC presented an alternative gas cost-of-service study in which commercial and industrial G-1 and G-6 customers are disaggregated further into separate sales classes and transportation classes. With respect to the allocation methodologies utilized to assign costs to these classes, KIUC adopts the same methodologies employed by LG&E in its study.[131]

KIUC's reliance on load factor and customer size data to prove a significant difference in cost incurrence characteristics is not sufficient to convince the Commission that such an extreme cost differential exists. LG&E has clearly shown that all but one of its transportation customers also relied upon and used sales

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129 Eisdorfer Direct Testimony, page 3.

130 Id., page 6.

131 Id., pages 8-9.

service to some degree during the test year.[132] This ability of transportation customers to rely upon and use sales services is a privilege not adequately considered by KIUC in its analysis. Nor does KIUC's analysis acknowledge that LG&E's distribution system is constructed in a manner so as to provide sales service to these customers whenever such service is demanded. These factors must be considered when attempting to determine differences in cost incurrence characteristics between customers. KIUC's evidence lacks such consideration and analysis.

LG&E has stated that certain differences exist in the provision of service to Rate G-6 customers and Rate G-7 customers.[133] Yet LG&E combined its one G-7 customer with the Rate G-6 class for purposes of its cost-of-service study. LG&E should, in subsequent cost-of-service studies, fully disaggregate Rate G-7 customers from those served under Rate G-6.

LG&E's gas cost-of-service study is acceptable and should be used as a starting point for gas rate design.

Revenue Allocation

Based on the results of its electric cost-of-service study, LG&E proposed to allocate increases to all customer classes ranging from 7.4 percent for the residential and street and outdoor lighting classes to 5.9 percent for the general service and special contract classes. LG&E indicated that its allocation

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132 T.E., Volume VII, November 26, 1990, page 93.

133 Walker Exhibit 2, page 1.

methodology was designed to achieve a better balance between class rates of return while maintaining rate stability and continuity.

LG&E proposed to allocate the full amount of the gas increase to the General Service ("G-1") rate. This proposal was based on the results of LG&E's cost-of-service study which showed that the rate of return for the residential class, which is served under the G-1 rate schedule, was significantly below rates of return for other classes. LG&E proposed no increases for its interruptible rate classes, G-6 and G-7, or for the Fort Knox special contract.

KIUC, based on its electric cost-of-service study, proposed allocations ranging from a 5.6 percent decrease for Carbon Graphite, a contract customer, to a 13.1 percent increase for the residential class. On gas, KIUC proposed decreases for G-1 and G-6 industrial transportation customers. The amount of the decreases were dependent on the amount by which the Commission reduced LG&E's requested gas increase. None of the other intervenors offered specific allocation recommendations.

LG&E's allocation proposals are supported by its cost-of-service analyses and are consistent with the Commission's goals of gradualism and rate continuity. Having accepted LG&E's cost-of-service studies, the Commission finds that the resulting allocation proposals produce an equitable distribution of the revenue increases granted and shall be reflected in the rate design approved herein.

Electric Rate Design

LG&E proposed generally uniform increases in customer, demand and energy charges with some changes in its existing tariffs and rate design. The changes included: switching from a minimum bill to a customer charge for its water heating, space heating, and traffic lighting rates; changes in demand ratchets that would impact the billing demands for large commercial and industrial customers; seasonal billing demands for industrial customers served under rate LP; and making time-of-day rates available for smaller sized industrial and commercial customers. In addition, LG&E proposed changes in Public Street Lighting ("PSL") and Outdoor Lighting ("OL") rates to equalize the prices, by lumens of output, between mercury vapor and high pressure sodium lights. LG&E also proposed to revise its interruptible service rider by increasing the monthly demand credit to $3.30 per KW.

Louisville opposed LG&E's proposed changes to the PSL rates contending that the marginal cost pricing methodology employed by LG&E unfairly impacted Louisville with its older, more fully depreciated street lighting system. Louisville recommended an alternative rate schedule based on embedded costs and proposed to be separated from LG&E's other PSL customers either through a special contract or by establishing a separate tariff classification.

Jefferson et al. proposed changing LG&E's residential rate structure from a flat summer rate and declining block winter rate to inverted block rates in both summer and winter. Jefferson et al. opines that LG&E was deficient in its response to the Commission's directive in Case No. 10064 that LG&E address the issues of inverted block rates in the summer and declining block winter rates.[134] Jefferson et al., based on its analysis of LG&E's cost-of-service study, contends that LG&E's temperature-sensitive loads (summer air conditioning and winter heating) have a major impact on LG&E's costs and the allocation of those costs. Jefferson et al. proposes that LG&E's cost recovery, through rates, should also reflect the impact of these temperature-sensitive loads.

Jefferson et al.'s proposal would reduce LG&E's energy rate for the first 600 KWH to 5.435¢ on a year-round basis compared to LG&E's existing rates of 6.402¢ and 5.833¢ in the summer and winter, respectively. Jefferson et al. would increase the rate for sales over 600 KWH to 8.189¢ in the summer and 6.227¢ in the winter compared to the existing rates of 6.402¢ in summer, and 4.528¢ in winter. These rates were based on Jefferson et al.'s analysis of LG&E's temperature-sensitive costs using the base, winter, and summer demands from LG&E's cost-of-service study and using one month of the test year, October 1989, as the measure of LG&E's non-temperature-sensitive load.

LG&E argues that while unit costs are higher in the summer than in the winter there is no load research evidence to support Jefferson et al.'s proposal. LG&E contends that its existing rate design reflects the differences in summer and winter unit costs and, through the declining block winter rate, attempts to reduce the average unit cost by spreading fixed costs over greater sales volumes. LG&E further contends that deficient recovery of

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134 Case No. 10064, Order dated August 10, 1988.

customer costs through the customer charge requires these costs to be recovered in the initial usage steps to prevent large users from paying a disproportionate share of these costs. Finally, LG&E argues that its declining block winter rates should be continued to promote off-peak loads and that customer acceptance and revenue stability must be included in any consideration of rate design changes.

The Commission finds most of LG&E's rate design changes proper and reasonable. On PSL and OL rates, the Commission finds LG&E's alternative proposal proper and reasonable. The alternative proposal, to which Louisville agreed, results in approximately equal percentage increases for existing lights, be they mercury vapor or high pressure sodium.[135] For mercury vapor lights installed in the future, the rates would be higher, based on LG&E's marginal costs, while for new high pressure sodium lights the rates would equal the rates for existing lights.

The Commission is not persuaded that LG&E's residential rates should be redesigned in the precise manner proposed by Jefferson et al.; however, we find that a change resulting in an inverted block summer rate is appropriate. The Commission finds there to be substantial support for Jefferson et al.'s proposed inverted summer rates. LG&E is a strong summer peaker with a significant amount of capacity installed to meet its residential air conditioning load. As LG&E pointed out, its unit costs are higher in the summer than in the winter largely due to the relatively

[135] T.E., Volume V, November 20, 1990, page 111.

small increment of energy sales associated with the capacity required to meet its air conditioning demands.[136] These summer load characteristics indicate that LG&E's temperature- sensitive load is a major contributor to its generating and transmission costs and point out the need for long-term reductions in peak demand that can translate into lower future costs.

The Commission considers reduced peak demand, improved system load factor, and lower unit costs to be common goals that are in the best interest of all parties. To that extent, we are not persuaded that LG&E's winter rate design should be modified. Increased off-peak loads can produce many of the same benefits as reduced on-peak loads.

In recognition of concerns about cost recovery, customer acceptance, and revenue stability we have chosen a moderate approach to the implementation of an inverted block summer rate. The summer energy rate will remain unchanged for the first 600 KWH usage; the summer energy charge increase will be assigned in total to the usage in excess of 600 KWH. Given the relatively small number of KWH sold in relation to the capacity needed to meet air conditioning demands, this increase should not affect LG&E's revenue stability.

Cable Television Attachment Charges ("CATV")

LG&E proposed increasing its charges for CATV pole attachments by approximately 35 percent. LG&E's calculation of these charges was based on the formula established by the

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136 Walker Direct Testimony, page 22.

Commission in Administrative Case No. 251[137] with an added cost component for tree trimming expense.

KCTA opposed the increase contending that LG&E's allocation of the entire amount of tree trimming expense included in Account 593.004, Tree Trimming of Electric Distribution Routes, to poles was improper. KCTA opined that the vast majority of the expense goes not to clear space for poles, but to clear space for LG&E's overhead conductions and services and for clearing a path for the span of lines between the poles. KCTA proposed allocating the tree trimming expense based on LG&E's investment in poles compared to its combined investment in poles, overhead conductors, and services, thereby increasing LG&E's pole attachment charges by approximately 14 percent. KCTA also proposed that the approved pole attachment rates be calculated using the overall rate of return approved by the Commission in this case.

LG&E argued that since the cable television lines are strung between the poles, those lines are benefited by the tree trimming that clears the path between the poles. LG&E also pointed out that pole attachment charges are assessed through a formula, based on the percentage of usable space, that uses an allocation factor to derive the appropriate charge.

The clearing of the span between the poles inures to the benefit of all parties whose lines cover the span, be they

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137 Administrative Case No. 251, The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments, Order dated August 12, 1982.

electric, telephone, or CATV. As such, the full amount of the tree trimming expense is properly includible in calculating the O & M component of the annual carrying cost used to derive the pole attachment charge. Applying the annual carrying charge to an allocated fix cost component, derived using the percentage of usable space, effectively allocates the O&M component of the annual carrying charge. The result is a pole attachment charge which reflects an equitable allocation and recovery of LG&E's costs. The pole attachment charges proposed by LG&E, modified to reflect the overall rate of return of 9.89 percent, are granted.

Gas Rate Design

For the G-1 class, LG&E proposed to increase customer charges by approximately 24 percent and commodity charges by approximately 1.8 percent. This proposal reflected the results of LG&E's cost-of-service study and the need to improve the residential rate of return. LG&E maintains that since the average residential usage is significantly smaller than the usage of the commercial and industrial classes served under Rate G-1, the customer charge, rather than the commodity charge, is the appropriate rate to increase for the purpose of achieving a better balance between class rates of return.

The AG opposed the proposed increase in the residential customer charge from $4.35 to $5.40, taking issue with several of LG&E's cost allocators used in arriving at its customer costs. The AG argued that the proposal acted as a disincentive for conservation by placing the bulk of the increase on the fixed portion of the customer's bill. The AG calculated a customer cost of $3.75 and opined that the existing charge of $4.35 was more than adequate.

Jefferson et al. maintained that the customer charge increase would overly burden the small, lower income customers in the residential class. Jefferson et al. argued that LG&E's stated intention of increasing the residential class rate of return was improper because the lower risk associated with serving the residential class should translate into a lower rate of return. Jefferson et al. proposed a rate design that included increasing the customer charge by 2.4 percent, the amount of the overall requested G-1 rate increase.

Although LG&E's proposal for increasing the customer charge may be logical and reasonable, the amount of the increase is not consistent with the Commission's goals of rate continuity and gradualism. While there is a lower risk associated with serving the residential class some increase in the residential class rate of return is warranted. As a means of achieving this increase in return, it is proper to assign the majority of the revenue increase to the customer charge. Given the magnitude of the increase, the Commission will assign the customer charge an increase of approximately 2.5 times the overall G-1 percentage increase, exclusive of gas cost revenues. The revenue increase of .9 percent results in a customer charge increase of 2.3 percent, producing a residential customer charge of $4.45. The non-residential customer charge will increase by a similar percentage, from $8.70 to $8.90.

Late Payment Charges

The AG proposed that LG&E's late payment charge be abolished. The AG argued that the charge was not cost-justified and that LG&E had not shown that the charge served as an incentive for prompt payment.

Jefferson et al. proposed a plan to change the way LG&E credits partial payments as a means of reducing the number of late payment charges imposed on customers with past due account balances. At present, LG&E credits partial payments first to the customer's past due balance, then to the current month's bill. Jefferson et al. pointed out that this procedure results in a customer being assessed a late payment charge when it makes a partial payment sufficient to cover its current month's bill because, after the payment is credited to the customer's past due balance, the remainder is not enough to cover the current month's balance. Jefferson et al. argued that this change would encourage customers to make timely payments on their current balances knowing there would be no late payment penalty assessed in a subsequent month when the current month's bill was paid in full.

LG&E argued that the existing procedure serves as an incentive for customers to pay off their past due balances and that the late payment charge functions as an incentive to encourage timely payments. LG&E also argued that if the late payment charge were abolished, the loss of the associated revenues would have to be incorporated into the rates charged all customers.

LG&E's late payment charge has been in its tariffs for many years. The AG performed no analysis on the effectiveness of this charge as an incentive for timely payment of bills. The Commission finds, as it did in LG&E's last rate case,[138] that the late payment charge serves as an incentive and has an important role in LG&E's bill collection strategy.

The arguments of Jefferson et al. to change the way LG&E credits partial payments are persuasive. The Commission finds Jefferson et al.'s plan to be a means of minimizing the instances of recurring late payment charges for customers experiencing payment problems. When a customer can pay the current month's bill plus make a payment toward its past due balance, the customer should not be assessed still another late payment charge.

The Commission is mindful of LG&E's concerns that implementation of Jefferson et al.'s proposal could result in customer laxity toward the payment of past due balances. In considering those concerns, the Commission notes that LG&E retains the ability to terminate service if payment is not eventually made. However, to minimize the need for such actions, the Commission will make the following modification to Jefferson et al.'s proposal to create an incentive for customers to reduce their past due balances: When a customer with a past due balance makes a partial payment sufficient to pay the bill for the current month's usage, plus pay $10.00 or 5 percent of the outstanding past due balance, whichever is greater, LG&E shall credit the

[138] Case No. 10064, Order dated April 20, 1989.

payment to the current month's bill first, then credit the remainder to the past due balance. Crediting the current month's bill first will eliminate the assessment of a late payment penalty on the current month's bill, and requiring some payment toward the past due balance as a prerequisite for such crediting provides the customer an incentive to reduce the past due balance. The Commission finds that such a plan is a reasonable modification to LG&E's current collection procedures and should be approved. LG&E is hereby directed to implement this change in the way it credits partial payments concurrent with the effective date of this Order.

Transportation Service/Standby Service

KIUC recommended that LG&E's tariffs be modified to make standby service optional for all gas transportation customers. KIUC claimed that, under LG&E's existing tariffs, transportation service exclusive of standby service was limited to Rate T transportation customers taking sales service under Rate G-7, Uncommitted Gas Service. KIUC argued that this prerequisite effectively forced transportation customers to take standby service under Rate TS which is available to customers served under sales rates G-1 and G-6.

LG&E contends that Rate T is available to G-1 and G-6 sales customers but that a customer served on Rate T will have no standby or back-up protection for its Rate T volumes other than the G-7 rate for uncommitted gas service.[139] LG&E maintains that

[139] T.E., Volume II, November 9, 1990, pages 115-116.

KIUC has misinterpreted the Rate T tariff regarding the precondition of being a G-7 sales customer.

The Commission can understand KIUC's reading and interpretation of the Rate T tariff language which states "available to commercial and industrial customers serviced under Rate G-7. . ." to mean that being a G-7 sales customer is required in order to receive transportation service under Rate T. We also understand LG&E's explanation that the intent of the tariff is to indicate that for customers taking transportation service under Rate T, LG&E will not be obligated to provide standby quantities other than the uncommitted gas available under Rate G-7. Some modification of the tariff language regarding the availability of Rate T is needed to eliminate this misunderstanding. The above-quoted reference to Rate G-7 should be eliminated and a description of the limited protection of uncommitted gas offered under Rate G-7 should be added. LG&E should so modify this tariff when it files its revised tariffs setting forth the rates approved in this proceeding.

<u>Pipeline Demand Charges</u>

KIUC proposed that the pipeline supplier's demand component of LG&E's G-6 rates be reduced. KIUC opined that G-6 customers, being subject to interruption during the winter, have a lower quality of service than G-1 customers, and that this lower quality of service should be reflected in lower rates. We do not agree.

Rate G-6 customers are subject to interruption for only 90 days during the winter season. LG&E's pipeline demand costs are lower due both to its storage capabilities and the interruptibility of rate G-6 customers.

KIUC presented no evidence or analysis to support its argument. G-6 customers receive firm service for all but 90 days of the year. The quality of their service is not significantly different than that of G-1 customers. In addition, LG&E's lower pipeline demand costs are flowed through to all customers, both firm and interruptible, regardless of whether the lower cost results from LG&E's storage capabilities or the interruptibility of its G-6 customers.

Fuel Adjustment Clause

KIUC proposed that LG&E's electric fuel costs be removed from the base energy charges contained in LG&E's tariffs. KIUC argued that fuel costs should be recovered solely through the operation of the fuel clause and should be shown separately from non-fuel costs.

We disagree. The fuel clause regulation, 807 KAR 5:056, requires the establishment of a level of fuel costs in base rates such that, at the time of setting the base rates, the fuel adjustment factor will be equal to zero.

Tariff Changes

The Commission has addressed a number of specific rate design and tariff changes proposed either by LG&E or the intervenors. Several of the changes proposed by LG&E include text additions, deletions, or revisions which were not challenged by any party. The Commission has reviewed all such changes and finds they should be approved. Due to their voluminous nature, these text changes are not included in the Appendix.

OTHER ISSUES

Management Audit

While the Commission is encouraged by the organizational efficiencies and expected savings described by LG&E concerning its work force, the Commission remains concerned that all aspects supporting LG&E's organization structure are not in place. LG&E has indicated that the restructuring or downsizing dealt primarily with management employees.[140] LG&E has apparently not completed its evaluation of human resources needs and systems, but has begun a process of continuous improvement recognizing that the changes will take time to implement properly.[141] LG&E further indicated that this was the first year that organizational development had been seriously included in LG&E's five year plan and that a manpower planning process was currently being designed for implementation in January 1991.[142]

The Commission fully expects LG&E to pursue in a prompt and expeditious manner the organizational and operational efficiencies described during this proceeding. LG&E's efforts in this area will be monitored by the Commission through the normal management audit follow-up process.

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140 T.E., Volume II, November 8, 1990, page 126.

141 Wood Direct Testimony, page 4.

142 T.E., Volume II, November 8, 1990, page 200.

LG&E also discussed the 4KV conversion program stating that the program was scheduled for completion in approximately the year 2004.[143] Because of the savings estimated by LG&E in an internal study, the Commission encourages LG&E to continue its dialogue with the Management Audit Staff regarding the optimal conversion schedule during the management audit follow-up process.

Energy Conservation Programs

Paddlewheel proposed that the Commission establish a task force to design and administer capacity-avoiding conservation programs for LG&E. Paddlewheel suggested that the task force include LG&E Staff, Commission Staff, traditional intervenors, and conservation experts located in LG&E's service territory. Paddlewheel opined that the Commission, or specifically Commission regulations, have impeded the development of conservation programs in Kentucky. Paddlewheel recommended that the Commission provide utilities incentives for conservation by allowing conservation expenditures to be treated as rate base investments on which a utility can earn a return rather than as operating expenses for which it will be reimbursed. Subsequent to the hearing, Paddlewheel filed a motion requesting the Commission enter an Order formally establishing a task force.

LG&E indicated it was interested in expanding its energy conservation programs and would agree with Paddlewheel that rate base treatment of conservation expenditures would serve as an incentive to encourage utilities to design and implement new

[143] T.E., Volume III, November 9, 1990, page 199.

conservation programs. LG&E also indicated it would like to participate in a collaborative process (task force) to develop new conservation programs.

The Commission endorses the proposal to establish a task force for the purpose of designing and overseeing new conservation programs at LG&E. The Commission is also agreeable to allowing utilities to earn a return on conservation expenditures as an incentive to encourage development of such programs.

The Commission notes that neither at present nor in the past has it had a regulation or policy that acted as a deterrent to utilities making conservation expenditures. In fact, over 9 years ago the Commission stated, "We have in mind an aggressive conservation program, which sees expenditures on conservation not as an unfortunate necessity or misguided effort, but rather as an <u>investment</u>, and as such an alternative to investment in added generating capacity."[144] (emphasis in original) We encourage LG&E and interested intervenors to begin discussion on these matters for the purpose of establishing general goals and establishing a task force, including Commission Staff, to develop new conservation programs for LG&E. However, nothing in Paddlewheel's motion convinces the Commission that there is a present need to order the establishment of such a task force.

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[144] Case No. 8177, General Adjustment of Electric Rates of Kentucky Utilities Company, Order dated September 11, 1981.

Cane Run Unit No. 3 ("Cane Run No. 3")

KIUC and Jefferson et al. recommend that LG&E be prohibited from retiring Cane Run No. 3 until an independent evaluation of the unit could be performed to determine its reliability and possible renovation to extend its active service life. Jefferson et al. also proposed that the Commission establish a process requiring a certificate of decommissioning be obtained by a utility prior to retiring a generating unit. After the hearing in this case, Paddlewheel moved to establish a case in order to investigate the status of Cane Run No. 3.

LG&E agreed that it would not retire, or take any measure to retire, Cane Run No. 3 until an independent evaluation was performed on the unit, either by someone chosen by the Commission or selected by agreement of the company and the intervenors.[145] LG&E did, however, have some questions as to the cost and payment for the evaluation and the time frame within which the study might be performed.

The Commission endorses the proposal agreed to by LG&E that an independent party be selected to perform an evaluation of Cane Run No. 3 prior to its retirement from service. LG&E should begin the process of selecting an independent expert to perform the evaluation. In the event that LG&E and the intervenors are unable to agree on an expert, the Commission will facilitate the selection. The cost, as with any outside service, should be borne by LG&E, with rate recovery at some future point. The Commission

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[145] T.E., Volume I, November 7, 1990, page 167.

would expect the evaluation to be completed prior to the time of LG&E's initial filing under the integrated resource planning regulation in late 1991. The Commission finds no need to establish a case at this time. Accordingly, Paddlewheel's motion will be denied.

Ohio Valley Electric Corporation ("OVEC") Power Agreement

LG&E is one of 15 owners of OVEC, an electric utility which sells power to the Department of Energy ("DOE") under a contract that expires in October 1992. If the DOE contract is not renewed in 1992, the OVEC power reverts to its owners. LG&E would have rights to 165 MW of OVEC capacity if the contract is not renewed.

KIUC recommended that the Commission implore LG&E to take reasonable steps to enhance the usefulness of the OVEC surplus capacity. KIUC proposed that the Commission hold LG&E financially responsible for the OVEC capacity by refusing to allow additional Trimble County capacity, or other capacity, in rate base so long as LG&E's surplus OVEC entitlement results in sufficient capacity to offset the need for additional Trimble County capacity.

LG&E should take reasonable steps to enhance the usefulness of surplus OVEC capacity and all other available capacity, be it through upgrading its hydro capacity or extending the useful life of Cane Run No. 3. All of these planning issues, and any new conservation programs, can be reviewed under the integrated resource planning regulation. As part of that review, and in future rate cases, the Commission will require that LG&E fully explore OVEC capacity, as well as other capacity alternatives, prior to allowing additional Trimble County capacity in rate base.

Reporting for the Holding Company

In the final Order in Case No. 89-374, the Commission indicated that LG&E should provide certain reports to the Commission concerning the activities of the Holding Company. Since the issuance of that Order, LG&E has become a subsidiary of the Holding Company, as was envisioned in the application in Case No. 89-374. The final Order in Case No. 89-374 did not contain a specific date on which LG&E was to begin providing the listed reports. LG&E should begin filing these reports immediately. Reports due annually should begin with calendar year 1990, and reports due quarterly should begin with the quarter ending December 31, 1990. These reports should be filed with the Commission within 30 days after the end of the reporting period.

SUMMARY

After consideration of all matters of record, the evidence, and being otherwise sufficiently advised, the Commission finds that:

1. The rates in the Appendix, attached hereto and incorporated herein, are the fair, just, and reasonable rates for LG&E to charge for service rendered on and after January 1, 1991.

2. The rates proposed by LG&E would produce revenue in excess of that found reasonable herein and should be denied.

IT IS THEREFORE ORDERED that:

1. The rates in the Appendix be and they hereby are approved for service rendered by LG&E on and after January 1, 1991.

2. The rates proposed by LG&E are hereby denied.

3. The tariff changes authorized herein are approved for service rendered on and after January 1, 1991.

4. Paddlewheel's motions to establish cases to designate a conservation task force and to investigate the status of Cane Run No. 3 be and they hereby are denied.

5. Within 30 days from the date of this Order, LG&E shall file with the Commission revised tariff sheets setting out the rate and tariff changes approved herein.

6. Annual reports concerning the Holding Company shall begin with calendar year 1990, while quarterly reports concerning the Holding Company shall begin with the quarter ending December 31, 1990. LG&E shall file these reports 30 days after the end of the reporting period.

Done at Frankfort, Kentucky, this 21st day of December, 1990.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 90-158 DATED 12/21/90

The following rates and charges are prescribed for the customers in the area served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE

RESIDENTIAL RATE
(RATE SCHEDULE R)

RATE:

Customer Charge: $3.29 per meter per month

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

First 600 kilowatt-hours per month	5.905¢ per KWH
Additional kilowatt-hours per month	4.584¢ per KWH

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

First 600 kilowatt-hours per month	6.402¢ per KWH
Additional kilowatt-hours per month	6.555¢ per KWH

WATER HEATING RATE
(RATE SCHEDULE WH)

RATE:

Customer Charge: $0.93 per meter per month.

All kilowatt-hours per month 4.339¢ per KWH

Minimum Bill: The customer charge.

GENERAL SERVICE RATE
(RATE SCHEDULE GS)

RATE:

Customer Charge:

$3.89 per meter per month for single-phase service
$7.78 per meter per month for three-phase service

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

All kilowatt-hours per month 6.317¢ per KWH

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month 7.102¢ per KWH

SPECIAL RATE FOR ELECTRIC SPACE HEATING SERVICE
RATE SCHEDULE GS

RATE:

Customer Charge: $2.24

For all consumption recorded on the separate meter during the heating season the rate shall be 4.568¢ per kilowatt-hour.

Minimum Bill: The customer charge. This minimum charge is in addition to the regular monthly minimum of Rate GS to which this rider applies.

LARGE COMMERCIAL RATE
(RATE SCHEDULE LC)

RATE:

Customer Charge: $17.09 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution
Winter Rate: (Applicable during 8 monthly billing periods of October through May)		
All kilowatts of billing demand	$7.33 per KW per month	$5.68 per KW per month
Summer Rate: (Applicable during 4 monthly billing periods of June through September)		
All kilowatts of billing demand	$10.43 per KW per month	$8.53 per KW per month

Energy Charge:

All kilowatt-hours per month 3.139¢

LARGE COMMERCIAL TIME-OF-DAY RATE

RATE:

Customer Charge: $18.92 per delivery point per month

Demand Charge:

Basic Demand Charge	
Secondary Distribution	$3.71 per KW per month
Primary Distribution	$2.01 per KW per month
Peak Period Demand Charge	
Summer Peak Period	$6.72 per KW per month
Winter Peak Period	$3.57 per KW per month

Energy Charge: 3.139¢ per KWH

INDUSTRIAL POWER
(RATE SCHEDULE LP)

RATE:

Customer Charge: $42.22 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution	Transmission Line
Winter Rate: (Applicable during 8-monthly billing periods of October through May)			
All kilowatts of billing demand	$8.19 per KW per month	$6.24 per KW per month	$5.03 per KW per month
Summer Rate: (Applicable during 4-monthly billing periods of June through September)			
All kilowatts of billing demand	$10.82 per KW per month	$8.88 per KW per month	$7.66 per KW per month

Energy Charge:

All kilowatt-hours per month 2.716¢ per KWH

INTERRUPTIBLE SERVICE

RATE:

The monthly bill for service under this rider shall be determined in accordance with the provisions of either Rate LC, Rate LC-TOD, Rate LP, or Rate LP-TOD, except there shall be an interruptible demand credit of $3.30 per kilowatt per month.

INDUSTRIAL POWER TIME-OF-DAY RATE
(RATE SCHEDULE LP-TOD)

RATE:

Customer Charge: $44.31 per delivery point per month

Demand Charge:

Basic Demand Charge:	
Secondary Distribution	$5.32 per KW per month
Primary Distribution	$3.34 per KW per month
Transmission Line	$2.13 per KW per month
Peak Period Demand Charge:	
Summer Peak Period	$5.57 per KW per month
Winter Peak Period	$2.96 per KW per month

Energy Charge: 2.708¢ per KWH

OUTDOOR LIGHTING SERVICE
(RATE SCHEDULE OL)

RATE:

	Rate Per Month Per Unit	
	Installed Prior to January 1, 1991	Installed After December 31, 1990
Overhead Service		
Mercury Vapor		
100 watt*	$6.92	$ -0-
175 watt	7.83	9.23
250 watt	8.87	10.32
400 watt	10.80	12.37
1000 watt	19.69	22.32
High Pressure Sodium Vapor		
100 watt	$7.69	$7.69
150 watt	9.84	9.84
250 watt	11.62	11.62
400 watt	12.27	12.27
Underground Service		
Mercury Vapor		
100 Watt - Top Mounted	$12.06	$12.81
175 Watt - Top Mounted	12.83	13.81

High Pressure Sodium Vapor		
100 Watt - Top Mounted	$14.19	$14.19
150 Watt	19.33	19.33
250 Watt	22.17	22.17
400 Watt	24.40	24.40

* Restricted to those units in service on 5-31-79.

Special Terms and Conditions:

Company will furnish and install the lighting unit complete with lamp, fixture or luminaire, control device and mast arm. The above rates for overhead service contemplate installation on an existing wood pole with service supplied from overhead circuits only; provided, however, that when possible, floodlights served hereunder may be attached to existing metal street lighting standards supplied from overhead service. If the location of an existing pole is not suitable for the installation of a lighting unit, the Company will extend its secondary conductor one span and install an additional pole for the support of such unit. The customer to pay an additional charge of $1.64 per month for each such pole so installed. If still further poles or conductors are required to extend service to the lighting unit, the customer will be required to make a non-refundable cash advance equal to the installed cost of such further facilities.

PUBLIC STREET LIGHTING SERVICE (RATE SCHEDULE PSL)

RATE:

	Rate Per Month Per Unit	
	Installed Prior to January 1, 1991	Installed After December 31, 1990
Type of Unit		
Overhead Service		
Mercury Vapor		
100 Watt (open bottom fixture)	$6.22	$ -0-
175 Watt	7.28	9.05
250 Watt	8.28	10.15
400 Watt	9.90	12.20
400 Watt (underground pole)	14.31	-0-
1000 Watt	18.39	22.07

<u>High Pressure Sodium Vapor</u>		
150 Watt	8.90	8.90
250 Watt	10.66	10.66
400 Watt	11.10	11.10
<u>Underground Service</u>		
<u>Mercury Vapor</u>		
100 Watt - Top Mounted	10.16	12.55
175 Watt - Top Mounted	11.12	13.63
175 Watt	15.09	21.47
250 Watt	16.12	22.57
400 Watt	18.96	24.62
400 Watt on State of KY Pole	11.21	-0-
<u>High Pressure Sodium Vapor</u>		
100 Watt - Top Mounted	11.17	11.17
150 Watt	19.32	19.32
250 Watt	20.50	20.50
250 Watt on State of KY Pole	10.48	-0-
400 Watt	21.95	21.95
<u>Incandescent</u>		
1500 Lumen	8.29	-0-
6000 Lumen	10.91	-0-

STREET LIGHTING ENERGY RATE (RATE SCHEDULE SLE)

RATE: $3.972¢ per kilowatt hour

TRAFFIC LIGHTING ENERGY RATE (RATE SCHEDULE TLE)

RATE:

<u>Customer Charge:</u>	$2.45 per meter per month
All kilowatt-hour per month	4.992¢ per KWH
<u>Minimum Bill</u>	The customer charge.

SPECIAL CONTRACT FOR ELECTRIC SERVICE
CARBON GRAPHITE SPECIAL CONTRACT

<u>Demand Charge</u>

Primary Power (28,500 KW)	$11.82 per KW per month
Secondary Power (Excess KW)	$5.91 per KW per month
Demand Credit for Primary Interruptible Power (24,500 KW)	$3.30 per KW per month
Energy Charge All KWH	1.946¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
E. I. DUPONT DE NEMOURS SPECIAL CONTRACT

<u>Demand Charge</u>

$11.14 per KW of billing demand per month

<u>Energy Charge</u>

2.012¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
FORT KNOX SPECIAL CONTRACT

<u>Demand Charge</u>

Winter Rate:
(Applicable during 8 monthly billing periods of October through May)

All KW of Billing Demand	$6.32 per KW per month

Summer Rate:
(Applicable during 4 monthly billing periods of June through September)

All KW of Billing Demand	$8.52 per KW per month
Energy Charge: All KWH per month	2.605¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
LOUISVILLE WATER COMPANY SPECIAL CONTRACT

Demand Charge

$7.62 per KW of billing demand per month

Energy Charge

2.138¢ per KWH

GAS SERVICE

The Gas Supply Cost component in the following rates has been adjusted to incorporate all changes through Case No. 10064-J.

GENERAL GAS RATE
G-1

RATE:

Customer Charge:

$4.45 per delivery point per month for residential service
$8.90 per delivery point per month for non-residential service

Charge Per 100 Cubic Feet:

Distribution Cost Component	11.075¢
Gas Supply Cost Component	27.323¢
Total Charge Per 100 Cubic Feet	38.398¢

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE G-1

RATE:

The rate for "Summer Air Conditioning Consumption," as described in the manner hereinafter prescribed, shall be as follows:

Charge Per 100 Cubic Feet:

Distribution Cost Component	6.075¢
Gas Supply Cost Component	27.323¢
Total Charge Per 100 Cubic Feet	33.398¢

GAS TRANSPORTATION SERVICE/STANDBY RATE TS

RATE:

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $90.00 per delivery point per month.

	G-1	G-6
Distribution Charge Per Mcf	$1.1075	$0.5300
Pipeline Supplier's Demand Component	.2032	.2032
Total	$1.3107	$0.7332

EXHIBIT__(LK-PSC-13-3)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY TO ADJUST ELECTRIC RATES	) CASE NO. 91-370

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY TO ADJUST ELECTRIC RATES	) CASE NO. 91-370

O R D E R

On November 4, 1991, The Union Light, Heat and Power Company ("ULH&P") filed an application with the Commission requesting authority to increase its electric rates for service rendered on and after December 4, 1991. The proposed rates would increase annual electric revenues by $29,702,741, an increase of 20.4 percent, based on normalized test-year sales. This Order grants an increase in annual electric revenues of $22,334,942, an increase of 15.1 percent, based on normalized test-year sales.

The Commission granted motions to intervene filed by the Attorney General, by and through his Utility and Rate Intervention Division ("AG"); the Newport Steel Corporation ("Newport Steel"); and joint movants Virginia Anderson, Hazel Buchanan, and Citizens Organized to End Poverty in the Commonwealth ("CO-EPIC").

The Commission suspended the proposed rate increase through May 3, 1992 in order to conduct an investigation into the reasonableness of the proposed rates. A public comment hearing was held at Thomas More College in Crestview Hills, Kentucky, on March 5, 1992, to allow interested parties an opportunity to express their concerns about ULH&P's proposed rate increase. A public hearing was held in the Commission's offices in Frankfort, Kentucky, on March 17-20 and 23, 1992 with all parties of record represented. Simultaneous briefs were filed on April 20, 1992. All information requested during the hearing has been submitted.

On February 10, 1992, ULH&P filed a petition requesting authority to record on its books as a deferred debit the increase in purchased power expense to be incurred as a result of a decision by the Federal Energy Regulatory Commission ("FERC") to allow increased rates for purchased power to become effective subject to refund on February 13, 1992. The increased rates for purchased power were requested by Cincinnati Gas and Electric Company ("CG&E"), the parent and wholesale power supplier of ULH&P. This issue was heard at the commencement of the public hearing on March 17, 1992. On April 17, 1992, the Commission denied ULH&P's request.

COMMENTARY

ULH&P operates as a public utility providing electric and gas service in Boone, Campbell, Grant, Kenton, and Pendleton counties. Within those counties, ULH&P distributes and sells electricity to approximately 106,270 customers.

TEST PERIOD

ULH&P proposed and the Commission has accepted the 12-month period ending July 31, 1991 as the test period for determining the reasonableness of the proposed rates. In utilizing the historic test period, the Commission has given full consideration to appropriate known and measurable changes.

NET ORIGINAL COST RATE BASE

ULH&P proposed a jurisdictional net original cost rate base of $95,645,272.[1] The Commission has made the following modifications to the proposed rate base:

Accumulated Depreciation

In computing its proposed electric jurisdictional net original cost rate base, ULH&P used the test-year end balance for accumulated depreciation. The AG proposed that the test-year end balance should be adjusted to reflect his proposed depreciation adjustment. The AG noted that the Commission routinely adjusts accumulated depreciation by the amount of the depreciation adjustment, and that ULH&P offered no evidence on why this adjustment was inappropriate.[2] ULH&P responded that it never believed this adjustment was appropriate because it improperly values the plant as of the end of the test year, improperly reflects an ongoing level of plant, and represents an arbitrary adjustment which is both inappropriate and inconsistent with the treatment of similar adjustments made to operating results.[3] However, ULH&P presented no evidence to support these allegations.

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1 Schedule B-1 of the Application.

2 DeWard Direct Testimony, page 8.

3 Lonneman Rebuttal Testimony, page 2.

We note that the AG has correctly stated the past practice employed by the Commission. The arguments presented by ULH&P have not persuaded us to reject the AG's adjustment. No authoritative basis has been offered by ULH&P to support a departure from the Commission's long standing practice. Therefore, the Commission will include adjustments to test-year depreciation expense, explained elsewhere in this Order, in the accumulated depreciation used in the determination of rate base. The adjustments increase accumulated depreciation by $14,909.

Prepayments

ULH&P proposed to include $83,041 for the PSC Assessment[4] and $5,236 for auto license taxes as a part of the prepayments component of rate base. ULH&P argues that such expenses, which are applicable to more than a one month period, are considered to be a prepayment. These expenses represent funds which, in ULH&P's opinion, had to be expended prior to their recovery through rates and should be recognized in rate base to compensate ULH&P for this delayed recovery.[5] The AG proposed to remove these two items from the rate base determination, citing the fact that the Commission did so in Case No. 90-041.[6]

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4 Referred to by ULH&P as "KYPSC Maintenance Tax."

5 Response to the Commission's Order dated December 17, 1991, Item 5.

6 DeWard Direct Testimony, page 10.

The Commission is not persuaded by ULH&P's arguments. The classification of the PSC Assessment and auto license taxes as prepayments allows ULH&P to recognize the expense over the entire year, rather than in the month of payment. ULH&P has not performed any lead or lag analysis on these payments. Also, ULH&P has not satisfactorily explained why it should earn a return on taxes it has already paid. As the Commission determined in Case No. 90-041:

> [T]he PSC Assessment and the auto license taxes represent liabilities which are paid for a specific, present time obligation. The rationale employed by ULH&P could be just as easily applied to other of its obligations, such as property taxes and income taxes. . . . These taxes are included in the operating expenses of ULH&P and are recovered from ratepayers through rates. ULH&P would enjoy a double benefit if it were also allowed to earn a return on these taxes.[7]

The Commission has excluded the PSC Assessment and the auto license taxes from the prepayments included in the rate base.

Cash Working Capital Allowance

ULH&P proposed to include in rate base $6,252,870 as a cash working capital allowance. ULH&P determined the allowance using the 45 day or 1/8 formula methodology and then added 10 days of purchased power expense. ULH&P stated that the 10 days represent the number of days it has to finance the purchased power costs before recovery is received from customers. ULH&P arrived at the 10 day figure by combining the number of days after the end of the

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[7] Case No. 90-041, An Adjustment of Gas and Electric Rates of The Union Light, Heat and Power Company, Order dated October 2, 1990, page 10.

month it pays its purchased power bill, with the midpoint number of days for a consumption period. This equals 35 days. This sum was then subtracted from the 45 days used in the traditional formula approach.[8] ULH&P also noted that FERC adjusts for purchased power when it uses the formula approach.[9]

The AG opposed the inclusion of the 10 days of purchased power expense in ULH&P's calculation of cash working capital. The AG argued that inclusion of this one item was inappropriate, and excludes other items which have substantial lead days.[10]

The Commission has traditionally used the 1/8 formula approach in electric utility rate cases and find no basis to now depart from that practice. Concerning the addition of purchased power expense to that calculation, the Commission notes that ULH&P has performed no lead-lag studies for this case.[11] Thus, the use of 10 days is at best an assumption of the time this expense must be financed, not a known period of time. The Commission also notes that FERC will allow an adjustment to the results of the 1/8 formula method when it has been demonstrated that fossil fuel

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8 Bruegge Direct Testimony, pages 5 and 6.

9 Transcript of Evidence ("T.E."), Vol. I, March 17, 1992, page 207.

10 DeWard Direct Testimony, page 7.

11 T.E., Vol. I, March 17, 1992, page 208.

expense is a substantial component of the operation and maintenance expenses and the actual lag in the payment of fossil fuel is known. If an adjustment of fuel expense lag is made by FERC, then a further adjustment will be made to the formula results to recognize the increased importance to the utility of purchased power expense.[12] We cannot adopt ULH&P's proposed modification to the traditional 1/8 formula methodology, even if we chose to follow the stated position of FERC. As ULH&P has noted in its brief, "[t]he Commission has been presented with no evidence which would support departure from past practice."[13] Therefore, we have adjusted the allowance for cash working capital to exclude the 10 days of purchased power expense and to reflect the accepted pro forma adjustments to operation and maintenance expenses, which results in a cash working capital allowance of $2,535,132.

Deferred Income Taxes

ULH&P deducted $13,726,430 in deferred income taxes in the calculation of its rate base. The AG proposed an offset reduction to rate base of $2,256,871, which represents his calculation of the accrued liability associated with uncollectible accounts, post-retirement benefits, and vacation pay. The AG claims that without this adjustment ratepayers will be required to pay for the

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[12] Response to AG Hearing Data Request No. 7, Docket No. RM84-9-000, Calculation of Cash Working Capital Allowance for Electric Utilities, Termination Order dated October 15, 1990.

[13] Brief of ULH&P, page 8.

recorded book expenses as well as a return on the deferred tax charges included in rate base. The AG further claims that his adjustment allows ratepayers some measure of relief from these expenses which are recorded on ULH&P's books but are not funded.[14]

ULH&P opposed the AG proposal, noting that these accounts reflect situations where the book expense occurs before the tax deduction. Because deferred tax accounting has been followed, the ratepayer has benefitted from lower tax expense.[15]

The Commission notes that the AG proposed a similar adjustment in Case No. 90-041, except that he only proposed to eliminate the questioned deferred tax balances, not a corresponding accrued liability. However, the evidence convinces the Commission that the findings adopted in Case No. 90-041 should be readopted here:

> [r]atepayers have benefited from deferred income tax debits since at the time the debits were recorded, book income tax expense was lower than the actual income tax liability. Ratepayers benefit from deferred income tax credits as the tax timing differences which produced the credits reverse.[16]

The Commission will include in the determination of ULH&P's jurisdictional net original cost rate base the test-year end balances of the deferred income taxes, as were included by ULH&P.

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[14] DeWard Direct Testimony, page 9.

[15] Brief of ULH&P, page 9.

[16] Case No. 90-041, Order dated October 2, 1990, page 12.

Based upon the previous findings, the Commission has determined the jurisdictional electric net original cost rate base for ULH&P at July 31, 1991 to be as follows:

Total Utility Plant	$151,975,821
Add:	
Materials and Supplies -	
Distribution	70,214
Other	10,933
Total Materials and Supplies	81,147
Prepayments	144,418
Cash Working Capital Allowance	2,535,132
Subtotal	2,760,697
Deduct:	
Reserve for Accumulated Depreciation	49,093,137
Accumulated Deferred Income Taxes	13,726,430
Investment Tax Credits	96,010
Subtotal	62,915,577
Total Jurisdictional Electric Net Original Cost Rate Base	$ 91,820,941

CAPITAL

ULH&P proposed a total capitalization of $161,152,742.[17] The proposed capitalization included the average daily balance of short-term borrowings for the test year and the total of all investment tax credits as of the test-year end.

The AG proposed a total capitalization of $162,116,790.[18] The difference between the AG's proposal and ULH&P's was that the AG

17 Mosley Direct Testimony, Exhibit JRM, page 1 of 7.

18 Weaver Direct Testimony, Exhibit CGK Weaver, Statement 20.

did not include the unamortized premiums and discounts on long-term debt in his total.

At test-year end, ULH&P's total capitalization, before the inclusion of Job Development Investment Tax Credits ("JDIC"), was $161,674,762.[19] In ULH&P's past cases, the Commission has generally allocated capital between electric and gas operations to determine the appropriate capital valuation for each type of utility service. The Commission believes that the use of this method is appropriate for rate-making purposes and has determined ULH&P's jurisdictional capital devoted to electric operations to be 52.771 percent of total capitalization based on the ratio of electric operations rate base to total company rate base as determined in Appendix B. The resulting capital assigned to jurisdictional electric operations is $85,316,929.

The Commission has increased this $85,316,929 by $3,706,088,[20] which is the jurisdictional amount of JDIC applicable to electric operations. The JDIC has been allocated to each component of capital based on the ratio of each capital component to total capital excluding JDIC. Both ULH&P and the AG included all investment tax credits as JDIC, without removing the investment tax credits included in the determination of rate base

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19 Schedule A-3.9 of the Application and the Response to the Commission's Order dated November 14, 1991, Item 1, page 4 of 8.

20 Schedule B-6 of the Application, lines 3 and 4.

from the total or excluding the non-jurisdictional portion of the investment tax credits. ULH&P and the AG did not allocate the amounts to the components of capital. The Commission has traditionally followed the practice of allocating JDIC to the capital components. This treatment is entirely consistent with the requirements of the Internal Revenue Service that JDIC receive the same overall return allowed on the components of capitalization.

REVENUE AND EXPENSES

For the test period, ULH&P had actual electric jurisdictional net operating income of $8,982,177. ULH&P proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions which resulted in an adjusted jurisdictional net operating income of a negative $6,857,458.[21] The proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications:

Weather Normalization

ULH&P proposed an adjustment to reduce revenues by $1,526,929 to reflect the test year's deviation from normal temperatures as measured in cooling degree days and heating degree days. ULH&P determined its normal temperatures and normal degree days based on the 30-year average data published by the National Oceanic and Atmospheric Administration ("NOAA") for the period from 1951 through 1980.

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21 Schedule C-2 of the Application.

The AG recommended that the Commission reject the proposed adjustment claiming, among other things, that (1) the methodology used by ULH&P to calculate the adjustment was questionable; (2) ULH&P's model does not separately identify temperature-sensitive load and non-temperature-sensitive load; (3) the proposal does not take into consideration the affects of weather on CG&E's allocation of costs to ULH&P; (4) the 30-year data for the period ended 1980 does not reflect the impact of the warming trend of the past decade; and (5) ULH&P's choice of a test year ended July 31, 1991 greatly impacts the magnitude of the adjustment.

ULH&P took issue with the AG's claims and defended its adjustment as one that produces reasonable results for rate-making purposes. ULH&P claimed that its methodology was appropriate and fully documented, and that separating loads into temperature-sensitive and non-temperature- sensitive components would introduce additional error into the weather normalization process. ULH&P stated that CG&E's cost allocation was based on a future test year that included normal temperatures and ULH&P opined that neither it nor this Commission should rely on any temperature normals other than the 30-year data published by NOAA. Finally, ULH&P argued that its choice of test year was not related to its proposed weather normalization adjustment but, if that were the case, it might have chosen the 12 months ended May 31, 1991, as suggested by the AG.

The Commission has a number of concerns. We are not persuaded that ULH&P's methodology is acceptable for rate-making purposes nor are we persuaded that it is appropriate for an electric utility to attempt to normalize for weather while ignoring the other factors that affect energy usage. ULH&P contends that altering its method to separate loads into temperature-sensitive and non-temperature-sensitive components would introduce additional error into the normalization process; however, it did not support this contention nor did it consider whether such a separation might improve its determination of the level of weather normalized sales. ULH&P used its load forecasting model to derive its weather normalization adjustment and held all variables within the model, other than the weather variable, constant, or at actual test-year levels. This approach does not consider, or attempt to normalize, these other variables which is in direct opposition to a prior Commission opinion on this subject.[22]

The Commission has reviewed the applicable publications referenced by ULH&P concerning official weather normals as established by NOAA. Our review indicates that the 1951-1980 data is the most current official 30-year data available, as ULH&P claims. Our review also indicates that NOAA makes available sufficient information to enable someone to replicate that data or perform a comparable calculation for a different period of time. As indicated in other cases, the Commission considers it important

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22 Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, Order dated July 1, 1988.

that weather data be current.[23] ULH&P's normalization adjustment does not recognize the impact that temperatures in recent years might have on determining normal temperatures.

The Commission is also concerned about the accuracy of ULH&P's approach to calculating billing-degree days for its 21 billing cycles. In its calculation, ULH&P gives equal weight to each of the 21 billing cycles even though (1) the number of days in each billing cycle can vary from month to month and (2) the number of customers per class for each billing cycle is not available for comparison. This approach may not properly match customers' loads and their corresponding bills since each billing cycle has different beginning and ending dates with a specific number of degree days and a specific number of customers for each month of the year. Although ULH&P indicated other utilities had researched this matter and found the potential for greater accuracy from use of a more detailed weighting approach was not statistically significant, ULH&P had not made a similar independent determination. Absent such a determination, we are not persuaded that the equal weighting approach used by ULH&P is sufficiently accurate for use in the rate-making process.

ULH&P's proposed weather normalization adjustment is denied. This results in an increase of $1,526,929 to ULH&P's normalized revenues, and will impact ULH&P's adjusted purchased power cost, supra.

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23 Id.

Interruptible Credit - Newport Steel

As part of its revenue normalization calculation, ULH&P adjusted its revenues to reflect a full 12 months at the rates in effect at test-year end. One component of ULH&P's adjustment was the annualization of the interruptible credit to Newport Steel based on the terms of the 1991 service agreement between ULH&P and Newport Steel and the level of firm, curtailable, and interruptible demands designated by Newport Steel for the last month of the test year. The annualization of Newport Steel's interruptible credit reduces ULH&P's revenues by $1,521,275.

The AG made two proposals concerning the Newport Steel interruptible credit. The first proposal, that ULH&P's annualization adjustment be disallowed, is based on the AG's concerns about the terms of the service agreement, the lack of any showing that the interruptible nature of the Newport Steel portion of ULH&P's load is properly reflected in CG&E's allocation of costs to ULH&P, and questions of whether the test year includes a representative, forward-looking level of sales to Newport Steel consistent with the terms and conditions of the agreement. The AG's second proposal is that the Commission disallow any interruptible credits in ULH&P's rates since ULH&P is not a generator of electricity. The AG suggests that all contracts for interruptible power should be between CG&E (the generator) and the interruptible customer. In arguing for this proposal, the AG contends that the amount of the monthly credit, $4.45 per KW at present and $5.25 per KW proposed, is excessive and is not based on the avoided cost of new generating capacity for CG&E, which supplies 100 percent of ULH&P's power requirements.

ULH&P and Newport Steel argued against the AG's proposals claiming that their service agreement was beneficial to ULH&P's ratepayers. Newport Steel, after calculating an avoided cost for CG&E of $7 per KW per month, opines that both the current and proposed credits are justified and that the difference between the credit and CG&E's avoided cost represents a savings, or benefit, to ULH&P's remaining customers. Newport Steel also opposed the AG's suggestion that CG&E contract directly with ULH&P's interruptible customers, maintaining that such an arrangement would unduly complicate the regulatory process by potentially involving three jurisdictions, Kentucky, Ohio, and the FERC, in the review of such contracts. Newport Steel did share the AG's concerns that CG&E's proposed allocation of costs to ULH&P at the wholesale level does not fully recognize the nature of Newport Steel's interruptible load. Newport Steel indicated that this problem could be remedied at the FERC level if the Commission was not able to address it in this proceeding and suggested the type of modification that CG&E could make to its cost allocation study.

The Commission is not persuaded that the amount of the credit is excessive, nor do we find that there has been established any link between the amount of the credit and CG&E's avoided cost of new capacity. The Commission will not revoke the agreement or direct ULH&P to forego entering into such agreements in the future. The agreement, as executed, was approved by Commission Order dated April 4, 1991,[24] after an earlier version of the agreement had been rejected on September 27, 1990.[25] Such agreements, properly reflected in the rate-making process, can be of long-term benefit to ULH&P, Newport Steel, and ULH&P's other customers as well. In this instance, however, the Commission has two concerns as to whether this agreement has been properly reflected in the rate-making process.

The Commission's first concern is that the allocation of costs to ULH&P by CG&E does not properly reflect the interruptible nature of Newport Steel's load. The record reflects that CG&E's pending FERC application, based on a coincident peak cost allocation methodology, does not take into account the fact that Newport Steel can be interrupted other than at the time of CG&E's coincident peak. In approving the agreement, the Commission presumed that all aspects of Newport Steel's interruptible load would flow through to CG&E since it is CG&E, not ULH&P, which controls the capacity and determines when loads will be interrupted. Since the entire CG&E system benefits from the interruptible nature of Newport Steel's load, ULH&P's customers, representing only 15 percent of the system, should not bear the

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24 Case No. 91-076, A Service Agreement Between The Union Light, Heat and Power Company and Newport Steel Corporation.

25 Case No. 90-068, A Service Agreement Between The Union Light, Heat and Power Company and Newport Steel Corporation.

brunt of the agreement's cost in the form of lower revenues through increased demand credits.

Our second concern deals with the demand level for Newport Steel included in the test year. Newport Steel's average monthly demand during the test year was 55,000 KW. In Case No. 90-068, ULH&P indicated that, with the operation of a third furnace, Newport Steel's monthly demand was expected to increase by one-half to approximately 80,000 to 85,000 KW with a corresponding increase in demand charge revenues.[26] ULH&P also indicated that, even with the larger demand credits under the new agreement, its annual revenues from Newport Steel would increase to $10.5 to $12 million compared to $9 to $9.5 million without the new agreement.[27] ULH&P's test-year revenues from Newport Steel, based on the test-year average demand, were $9.3 million.[28] However, ULH&P failed to propose any adjustment to reflect the anticipated increases in demand and revenues from Newport Steel.

It is apparent that ULH&P's adjustment to increase Newport Steel's interruptible demand credit only recognizes one aspect of their new service agreement. It is also apparent that ULH&P's purchased power cost does not equitably reflect the interruptible

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26 Response filed June 9, 1990 to the Commission's Information Request - First Set, Item 16.

27 Id.

28 The Union Light, Heat and Power Supplement C(9), WPC-3.1e.

nature of Newport Steel's load. For these reasons, the Commission has adopted the AG's recommendation to disallow ULH&P's proposed adjustment to annualize Newport Steel's interruptible credits. Such a disallowance increases ULH&P's normalized base revenues by $1,521,275 which, in turn, produces an increase of $9,843 in ULH&P's normalized forfeited discount revenue.

Fuel Synchronization

ULH&P initially proposed an adjustment to reduce fuel ("FAC") revenues by $200,996 in an attempt to match, or synchronize, FAC revenues with FAC expense. ULH&P modified its adjustment to produce a revenue reduction of $41,332. Both adjustments reflect the 2-month billing lag built into the FAC.

The AG recommended that ULH&P's proposal to reduce FAC revenues be rejected and proposed to increase such revenues by $244,578 over the actual test-year level. The AG argued that the adjustment should be based on test-year revenue levels rather than revenues for a period 2 months beyond the test year.

The Commission will accept the AG's proposal. The AG's adjustment is consistent with the approach used by the Commission in ULH&P's last case and in numerous other cases. While there is a 2-month billing lag inherent in the FAC mechanism, ULH&P's revenue requirements are being determined based on a 12-month test period ended July 31, 1991. ULH&P's approach doesn't consider the FAC revenues for the test period, but rather, the revenues for the 12 months ended September 30, 1991, 2 months beyond the test period. The purpose of the AG's adjustment is to eliminate any over- or under-recovery of fuel costs within the test year from the determination of revenue requirements. To achieve this purpose, the adjustment must be based on the fuel costs and fuel revenues reported during the test period upon which revenue requirements are being determined. This adjustment results in a $445,574 increase to ULH&P's normalized revenues.

Year-End Customer Adjustment

ULH&P proposed adjustments to increase revenues and purchased power costs by $283,687 and $244,063, respectively, based on the difference between the average number of customers served during the test year and the number of customers served as of the end of the test year. The increased KWH sales and increased KWH purchases included in the calculations reflected the impact of ULH&P's proposed weather normalization adjustment. The average cost per KWH as calculated by ULH&P reflected the projected increase in purchased power costs from CG&E.

Based on its proposal that ULH&P not be allowed to recover its increased purchased power costs, the AG argued that such costs should not be included in the calculation of the year-end customer adjustment. Based on this argument, the AG reduced ULH&P's year-end customer purchased power adjustment by $44,985.

The Commission has modified ULH&P's year-end customer adjustment to eliminate the impact of the proposed weather normalization adjustment from the calculations, consistent with our decision to reject the weather normalization adjustment. Based on actual test-year KWH sales and purchases, the increases to revenues and purchased power costs have been calculated to be $756,203 and $624,579, respectively.

Purchased Power Expense

ULH&P proposed an adjustment to increase its purchased power expense by $25,031,563. This adjustment reflected a proposed increase in CG&E's wholesale power rate, a reduction to ULH&P's purchased power volumes based on its proposed weather normalization adjustment and correction of a billing error in the last month of the test year. The increased wholesale power rate was allowed to go into effect February 13, 1992, subject to refund, pending final resolution of CG&E's rate case before the FERC.

The AG contends that the wholesale power contract between CG&E and ULH&P should be examined to determine whether ULH&P should have sought out other power suppliers. The AG argues that, while this Commission cannot rule on the reasonableness of CG&E's rate to ULH&P, it could find ULH&P's purchase from CG&E to be imprudent due to the existence of lower cost alternative power supplies. In support of this argument the AG cites a number of recent contracts for purchased power at rates less than those charged by CG&E. The AG goes on to argue that, as the contract between CG&E and ULH&P is a less-than-arm's length agreement and since ULH&P did not solicit bids from other suppliers, its purchase from CG&E is imprudent. The AG recommends that the Commission require ULH&P to solicit bids for other power supplies to ensure that customers' best interests are being served.

In addition to its bidding proposal, the AG opines that the Commission must deny ULH&P's requested adjustment on the grounds that it is not known and measurable. The argument goes that since the increased rate from CG&E is subject to refund pending the

FERC's final decision, the current rate is not permanent and will likely not be the final rate approved by FERC. The AG also questions whether this Commission can require ULH&P to make refunds to its customers of amounts refunded to ULH&P by CG&E in the event the FERC requires such refunds by CG&E.

ULH&P defended its decision to contract with CG&E for 100 percent of its power requirements. ULH&P opines that firm power, in the amount and quality required to meet its customers' needs, is not available in the region at a price less than the CG&E rate. ULH&P contends that power from other, further-away sources, while priced at rates comparable with CG&E, would incur wheeling charges that render it uneconomical.

ULH&P also claims that the AG's argument does not recognize all the additional costs ULH&P would incur to secure power from sources other than CG&E. Chief among these costs would be a capital investment of over $100 million for bulk power transmission facilities necessary for its own connections with other utilities. ULH&P also maintains that, under its contract with CG&E, it pays only for its monthly metered demand without incurring a minimum demand charge which it would incur if it were required to purchase power from another source.

ULH&P states that there is no reason for concern as to the protection of its customers in the event the FERC's final decision in the pending CG&E case produces a rate less than that allowed to go into effect February 13, 1992. ULH&P contends that any refund it receives from CG&E will, in turn, be refunded to its customers.

As the Commission stated in its December 13, 1991 Order, the FERC has exclusive jurisdiction to review and determine a reasonable rate for the sale of power to ULH&P. CG&E's request to increase the rate paid by ULH&P is intended solely to recover the substantial sums expended to convert the Zimmer Generating Plant ("Zimmer") from a nuclear to a coal-powered facility. Based upon our knowledge of the cost of Zimmer and the costs of comparable coal-powered generating plants, it is clear that the cost of Zimmer is excessive by at least 50 percent. Due to our lack of jurisdiction over CG&E's cost of Zimmer and the determination of a reasonable rate for power sales to ULH&P, we have intervened at the FERC and will vigorously oppose CG&E's attempts to recover unreasonable Zimmer costs from ULH&P.

The Commission is legally bound to accept as reasonable the purchased power rate as filed with the FERC and that filed rate must be recognized as a legitimate expense for retail rate-making purposes.[29] However, the courts have recognized a limited exception to this rule in situations where the affected utilities are not members of a regulated holding company. The exception allows a state commission to recognize in retail rates an amount less than the FERC filed rate if lower cost alternative power is available elsewhere.

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29 Mississippi Power and Light Co. v. Mississippi, ex rel. Moore, 487 U.S. 354 (1988).

In this case, the Commission can make no finding that lower cost alternative power is actually available. Even though we believe the cost of Zimmer to be excessive, the FERC filed rate is a composite rate which reflects the costs of all of CG&E's generating units, not just Zimmer. While the AG has alleged the existence of lower cost supplies, ULH&P has effectively refuted the allegations. The record shows the potential supplies identified by the AG to be either inferior in quality, i.e. less than firm power, or higher in price than the power ULH&P obtains from CG&E. Since ULH&P owns no generating facilities of its own, any power purchases must be of firm power which is available 24 hours per day, year round, in the contracted for quantities. The record is devoid of any credible evidence that a lower cost alternative supply is actually available. Absent this evidence, the Commission can make no finding that the FERC filed rate is unreasonably excessive in light of alternative power supplies.

The AG's contention that ULH&P's adjustment to increase purchased power expense is not known and measurable is unfounded. The rate ULH&P is being charged by CG&E has been accepted by, and is on file with, the FERC. This FERC filed rate is both known and measurable albeit potentially temporary in nature. As an intervenor in CG&E's pending case before the FERC, the Commission will be well aware of both the timing and magnitude of any reduction in CG&E's filed rate and will take the steps necessary to ensure that ULH&P's customers receive any refunds due them. The rates granted herein will be subject to refund pending a final decision by the FERC on CG&E's wholesale power rate.

The increase proposed by ULH&P has been modified to eliminate the impact of its proposed weather normalization adjustment. The modified increase, on a Kentucky jurisdictional basis, is $25,598,523.

Labor and Labor-Related Costs

ULH&P proposed adjustments to increase the test-year operating expenses by $233,378 for labor and labor-related costs. The actual cost items and the proposed adjustments to electric operations are as follows:

	Total
Wages and Salaries	$ 227,411
SIP & DCIP Plan Costs	3,184
FICA Taxes	2,783
	$ 233,378

Wages and Salaries. ULH&P proposed to increase wages and salaries by $227,411, to reflect the annualization of base wage increases granted to all employee groups during the test year. ULH&P calculated the adjustment by multiplying the average hourly wage increase by the number of hours charged to the electric operations, and then annualizing the result by the appropriate number of months.

ULH&P provided a series of workpapers which documented the hours worked during the test year by ULH&P employees for ULH&P activities.[30] The labor hour allocation process used by ULH&P and

[30] Application Workpapers WPC-3.4d through WPC-3.4o, also summarized as Staff Cross-Examination Exhibit No. 1 - Bruegge.

CG&E also includes the determination of hours worked by CG&E or other subsidiary employees for ULH&P activities and the hours worked by ULH&P employees for CG&E or other subsidiary activities. Documentation of these hours was not provided by ULH&P.

ULH&P provided a workpaper showing the allocation of hours worked by bargaining groups and account distribution for the month of May 1991. ULH&P bases its annual allocation of labor hours on the distributions developed from May data. This allocation process assigns hours to gas or electric operations, construction work in progress, retirement work in progress, work performed by other CG&E employees for ULH&P (referenced as accounts payable), and work performed by ULH&P employees for CG&E (accounts receivable).[31] While ULH&P has based its annual allocation on the activity in the month of May for many years, there has not been any verification undertaken by ULH&P to determine that May is the most representative month to use.[32]

The allocation percentages used in the May labor analysis are based on annual time studies. The time studies related to unionized labor groups usually are documented by work orders. The time studies for supervisory, administrative, and professional employees are based upon an annual study performed in October.

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31 Application Workpaper WPC-3.4b.

32 T.E., Vol. II, March 18, 1992, pages 44 and 45.

The hours reported in the study for this group are not based on the actual work performed in that month, but rather reflect what ULH&P purports to be a more "representative" or "normal" month.[33]

In reviewing the evidence provided by ULH&P concerning its labor hour allocation process, the Commission is concerned about several issues. First, the only allocation which should be needed for the hours worked by ULH&P employees for ULH&P activities would be between gas or electric operations, construction work in progress, and retirement work in progress. However, in determining the hours used in the wage normalization, the test-year actual hours worked by ULH&P for ULH&P were also allocated to the accounts payable and accounts receivable categories.

In reviewing the May labor hour allocations, the hours shown on that workpaper could not be matched or reconciled with the hours represented to be the actual hours worked by ULH&P for ULH&P for the month of May 1991. In the 1989 Management and Operations Review of ULH&P, the management auditors expressed concern about the time documentation process used in the supervisory, administrative, and professional group's time studies and recommended alternative methods be reviewed to develop more reliable means of gathering time data.[34] Furthermore, the Uniform

33 T.E., Vol. III, March 19, 1992, page 254; T.E., Vol. II, March 18, 1992, pages 44 and 45.

34 Management and Operations Review of The Union Light, Heat and Power Company, August 1989, pages 54 and 60.

System of Accounts for Electric and Gas Utilities ("USoA") requires that the distribution of employee wages "[s]hall be based upon the actual time engaged in the respective classes of work, or in case that method is impracticable, upon the basis of a study of the time actually engaged during a representative period."[35]

The Commission is not opposed to the concept of wage normalization. However, the problems we have noted concerning labor hour documentation and allocation make it impossible to verify the reasonableness of the proposed wage normalization adjustment. Therefore, the Commission must reject the $227,411 adjustment proposed by ULH&P. As recommended by the management auditors, the Commission instructs ULH&P to conduct a thorough review of its labor hour allocation and documentation processes and bring it into conformity with the requirements outlined in the USoA. This will require ULH&P to change the supervisory, administrative, and professional group's time study to one which is based on actual time worked. It will further require that ULH&P determine what is a representative period, which may include more than one month of a year.

<u>Savings Incentive Plan ("SIP") and Deferred Compensation and Investment Plan ("DCIP").</u> ULH&P proposed an increase of $3,184 for its SIP and DCIP. Executive, supervisory, administrative, and professional employees can participate in DCIP, while all other employees of ULH&P can participate in SIP. ULH&P determined the

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35 Uniform System of Accounts, Publication Number FERC-0114, General Instructions, No. 4.

increase by applying a cost factor to its proposed wage normalization adjustment. ULH&P stated that as wages increase, its contributions to the SIP and DCIP would also increase.[36] The AG opposed the inclusion of any costs associated with the DCIP, citing the current state of the economy and the size of ULH&P's proposed rate increase.[37]

The Commission is not persuaded to remove all costs of the DCIP. These types of fringe benefits are commonly provided by major utilities and there is no valid reason why such benefits should be denied to one class of ULH&P's employees and allowed for another. We have determined that ULH&P's contributions to the plans are a function of three independent factors: the number of employees enrolled in the plans; the amounts contributed by participating employees; and ULH&P's required matching contribution rate, which is limited to the first 5 percent of the participating employee's base pay.[38] Given these factors, it is inappropriate to calculate an increase for these contributions by simply applying a cost factor to the proposed wage normalization. Based on this finding, and the above finding to reject the

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36 Response to the Commission's Order dated December 17, 1991, Item 31.

37 DeWard Direct Testimony, pages 22 and 23.

38 Response to the Commission's Order dated November 14, 1991, Items 45(a) and 45(p).

proposed wage normalization adjustment, the Commission has not included the proposed increase in the costs of the SIP and DCIP.

FICA Taxes. ULH&P proposed to increase its FICA taxes by $2,783. The increase reflected changes in the FICA applicable base wage and tax rates which became effective January 1, 1991. The proposed adjustment was calculated on the 1990 calendar year wages and did not reflect the impact of wage increases granted between January 1991 and the test-year end.

In Case No. 90-041, the Commission expressed concern about ULH&P's presentation of wage adjustments and payroll tax adjustments based on different time periods. Using different time periods for these types of adjustments is inherently unreliable and inaccurate. ULH&P was instructed that, in future cases, adjustments to wages and salaries and payroll taxes should reflect the same time periods.[39] Despite this instruction, ULH&P has again presented these adjustments based on different time periods. Due to the improper calculation of the proposed adjustment to FICA taxes, the adjustment must be rejected.

Key Employee Annual Incentive Plan ("KEAIP"). The AG proposed to remove all test-year costs associated with the KEAIP. The AG included this proposal with this recommendation to remove all costs related to the DCIP. The amount the AG proposed to exclude contained test-year costs for both electric and gas operations.

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[39] Case No. 90-041, Order dated October 2, 1990, page 31.

Based on a thorough review of the KEAIP provisions, the Commission will exclude these expenses for the following reasons. First, while the plan does include so-called protection clauses for both customers and shareholders, the plan narrative clearly states that, "The Board, the Compensation Committee, and management all agree that the interests of shareholders must be paramount and protected when considering the appropriateness of any compensation program for key employees."[40] The Commission believes that, for a utility, the interests of the shareholders <u>and</u> the customers should be balanced and protected.

Second, in reviewing the performance objectives for calendar years 1990 and 1991, the 1991 performance objective targets were reduced only in those areas where in 1990 ULH&P and CG&E key employees had failed to reach the target.[41] ULH&P explained that some of these reduced targets were related to the fact that ULH&P and CG&E were going to be involved in rate cases during 1991.[42] However, in 1990 ULH&P was involved in a rate proceeding and it would not seem reasonable that pending cases in 1991 would be the sole reason to reduce performance objective targets. Finally, the Commission has carefully examined the evidence concerning the

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40 Response to the Commission's Order dated December 17, 1991, Item 60, page 2 of 4.

41 Response to the Commission's Order dated January 17, 1992, Item 43(d) and 43(e).

42 T.E., Vol. III, March 19, 1992, pages 216 and 217.

compensation and benefits available to these key employees. It appears that key employees received salary increases in addition to KEAIP payments[43] and that the overall benefits package, exclusive of the KEAIP payments, is quite adequate.[44]

The test-year expenses for KEAIP should not be included for rate-making purposes and electric operating expenses are reduced by $26,201.

Executive Severance Agreements. Included with the AG's proposal to remove the test-year expenses for DCIP and KEAIP was the removal of $166 of test-year expenses for executive severance agreements. The Commission has searched the record and is unable to find any evidence that the ratepayers were charged for executive severance agreements. We do note, however, that the expenses for the supplemental executive retirement plan were not included in this electric rate case.[45] Due to the minuscule amount of this proposed adjustment and the absence of verification that it was included in the test year, no adjustment to operating expenses will be made.

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43 Response to the Commission's Order dated November 14, 1991, Item 37.

44 Response to the Commission's Order dated December 17, 1991, Item 58.

45 Response to the AG's Supplemental Data Request, Item 44.

Meter Reading Workforce Reduction. The 1989 Management Audit Report included a recommendation that ULH&P undertake a re-routing of its meter reading routes. Although the work on this recommendation is still in progress, ULH&P indicated that it had already realized a reduction in the meter reading workforce of four employees, resulting in an annual wage savings of $125,000.[46] ULH&P proposed no adjustment to the test-year operations to reflect this savings.

It is appropriate to reflect these savings and accordingly test-year operating expenses have been reduced by $125,000.

Overtime Labor. In Case No. 90-041, the Commission expressed its concern over the increased levels of overtime hours incurred by ULH&P. In this case, ULH&P included a schedule showing the test-year actual and five previous calendar years' level of overtime hours.[47] This schedule shows that, with the exception of 1989, the level of overtime hours has been steadily increasing. ULH&P was asked to describe the steps taken by it and CG&E to control the level of overtime hours. However, ULH&P only responded that it had taken steps to utilize employees to the maximum effort possible, and provided no specific actions taken.[48]

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46 Response to the Commission's Order, dated January 17, 1992, Item 66(c).

47 Schedule C-11.1 of the Application.

48 T.E., Vol. III, March 19, 1992, page 237.

ULH&P has failed to recognize the ever increasing level of expense associated with overtime. No study or analysis has been performed to determine an optimal level of overtime or an optimal workforce level. Therefore, the Commission will reduce the overtime labor expense to reflect the historic average of overtime labor hours. We believe this approach results in a more reasonable level of expense under the circumstances in this case and have reduced operating expenses $74,287, as determined in Appendix C.

The Commission is also concerned by ULH&P's allocation of overtime labor hours. The overtime labor hours are converted to equivalent regular labor hours and allocated to the same accounts as the regular hours, regardless of the source of the overtime hours. ULH&P has performed no analysis to support the assumption that overtime labor hours should be allocated on the same basis as the regular labor hours. There is no evidence to demonstrate that ULH&P's current practice results in a reasonable allocation. The Commission will require ULH&P to modify its overtime labor hour allocation procedures in order that overtime will be allocated to the source of that overtime.

Labor Study. In Case No. 90-041, the Commission instructed ULH&P to provide a thorough analysis of its staffing levels with its next general rate case.[49] ULH&P did not provide or perform such an analysis. ULH&P indicated that it had not planned to file this

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[49] Case No. 90-041, Order dated October 2, 1990, page 34.

rate case and that it was not prepared to comply with the Commission's instructions.[50] In the 1989 Management Audit Report, several labor-related areas were identified as needing the attention of ULH&P.

The Commission is concerned about the numerous labor-related issues which have come to our attention during this proceeding. We believe the record clearly indicates that ULH&P must affirmatively address issues concerning its labor needs as part of the integrated CG&E system, the management of overtime hours, the reasonableness of current assumptions concerning spans-of-control, and all other management audit recommendations focusing on labor-related issues. The Commission expects that by the next general rate case, ULH&P will have taken appropriate constructive action on all of these issues. The Commission will evaluate the prudency of all ULH&P responses regarding labor and labor-related costs.

Uncollectible Accounts

As in past cases, ULH&P included in its requested revenue increase a commensurate increase in its provision for uncollectible accounts based upon its test-year provision for uncollectibles viewed as a percentage of total revenues. ULH&P used a test-year provision for uncollectibles, as a percentage of

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50 T.E., Vol. IV, March 20, 1992, page 71.

total revenues, of 1 percent.[51] However, this percentage reflected the blended provision for both gas and electric operations. The test-year electric provision for uncollectibles was .95 percent.[52] The Commission accepts ULH&P's methodology of adjusting uncollectible accounts, but will apply the test-year electric provision percentage rate to the revenues as adjusted in this Order. The Commission will determine ULH&P's revenue requirement using .95 percent to reflect the increase in uncollectible accounts expense associated with the revenue increase granted herein.

PSC Assessment

ULH&P included in its requested revenue increase a commensurate increase in the expense for the PSC Assessment, based upon the assessment rate in effect during the test year. The Commission accepts this proposal and has normalized the assessment based on the normalized revenues as adjusted in this Order. The Commission will include the PSC Assessment rate in the determination of ULH&P's revenue requirement.

Charitable Contributions

As it has in its three previous cases, ULH&P proposed an adjustment to increase operating expenses by $88,576 to reflect the expense for charitable contributions made during the test

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51 Application Workpaper WPC-12a.

52 Response to the Commission's Order dated December 17, 1991, Item 46.

year. While ULH&P acknowledged that the Commission has not recognized this adjustment in past decisions, ULH&P stressed that this is a necessary business expense which is a response to the needs and desires of the community.[53] However, ULH&P presented no new evidence, not previously considered by the Commission, to support this adjustment. The AG opposed the proposed adjustment, citing past Commission practice to deny such expenses.

The Commission has consistently excluded donations for rate-making purposes because the expense is not related to the provision of utility service. Donations enhance a utility's corporate image and are properly borne by the shareholders. ULH&P has failed to persuade us to include the expense in this case.

Rate Case Expenses

ULH&P proposed to adjust operating expenses by $50,000 to reflect its estimate of the entire cost of this rate case. Although no expenses related to this case were included in the test year, $17,968[54] related to Case No. 90-041 was included in the test year.

Throughout this proceeding, the Commission required ULH&P to provide the current actual rate case cost, with adequate supporting documentation. ULH&P was opposed to an ongoing filing

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53 Bruegge Direct Testimony, page 9.

54 Schedule C-10 of the Application.

but agreed to file its last updated actual rate case cost 20 calendar days after the completion of the public hearing.[55] The public hearing was completed on March 23, 1992, making the last update due April 12, 1992. ULH&P filed its last update with the Commission on April 22, 1992. The last update contained costs which were inadequately documented. Therefore, the Commission has rejected the April 22, 1992 filing and will use the cost information from the March 4, 1992 response as the basis for its adjustment. The actual rate case costs filed on March 4, 1992 totaled $35,742.

It would not be reasonable for ULH&P to recover the costs of this rate case every year that the rates established herein are in effect. It also would not be reasonable to use an estimated cost when the actual cost is known. The Commission believes it is appropriate in this case to amortize $35,742 in actual costs over a 3-year period, or an annual amortization of $11,914. The test-year expenses for Case No. 90-041 should be removed from operating expenses, resulting in a net reduction in operating expenses of $6,054.

Amortization of Management Audit Cost

ULH&P proposed to increase operating expenses $51,385 to reflect the annual amortization of its management audit costs. In

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[55] Response to the Commission's Order dated January 17, 1992, Item 46.

Case No. 90-041, the Commission approved ULH&P's proposal to amortize $257,067[56] in management audit costs over a 3-year period. At the end of the suspension period in this case, 17 months or $121,407[57] would remain to be amortized. At the present amortization rate, ULH&P would recover the cost by October 1993.

ULH&P is entitled under the management audit statute to recover the total cost of the management audit but it is not entitled to recover in excess of its cost. Thus, to avoid over-recovery, the amortization rate should be adjusted. The annual amortization rate for rate-making purposes should be $40,464 based on a 3-year amortization of the unamortized cost through the end of the suspension period. The electric portion of the revised amortization is 60 percent, or $24,278. Therefore, the Commission has increased operating expenses by $24,278.

Depreciation Expense

ULH&P proposed to increase depreciation expenses by $218,909. The adjustment reflected the normalization of depreciation expense on utility plant in service at test-year end. The AG proposed to reduce the normalized expense by $204,000 to reflect the over-depreciation of overhead street lighting plant.[58] The

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56 Case No. 90-041 Application Workpapers WPC-3.6a.

57 $257,067 multiplied by (17 months / 36 months).

58 DeWard Direct Testimony, page 31.

Commission has reviewed the utility plant information and has determined that the overhead street lighting account was fully depreciated at test-year end.[59] ULH&P has stated that it would stop depreciating the account at the time the net plant is zero.[60]

The Commission has included only $14,909 of the depreciation expense adjustment proposed by ULH&P. This adjustment has been included in the accumulated depreciation used to determine the jurisdictional electric net original cost rate base. This has been the Commission's traditional practice concerning depreciation expense adjustments.

Interest Synchronization

ULH&P proposed to adjust its interest expenses used in computing state and federal income taxes. ULH&P's approach was to apply the weighted cost of long-term debt to its rate base. The test-year actual interest expense was deducted from this amount to arrive at the adjustment to interest expense for the computation of income taxes.

Historically, for rate-making purposes, the Commission has imputed interest expense on the portion of JDIC assigned to the debt components of the capital structure and treated the interest as a deduction in computing the income tax expense allowed in the cost of service. The revenue requirements in this proceeding are

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59 Schedule B-3 of the Application, page 2 of 4.

60 T.E., Vol. I, March 17, 1992, page 176.

being determined from the capitalization rather than the rate base; therefore, the Commission believes its previous practice is more appropriate in determining the interest synchronization. This was the same approach used by the Commission in previous ULH&P general rate cases. The Commission has applied the applicable cost rates to the JDIC allocated to the debt components of the capital structure. ULH&P's interest expense applicable to Kentucky jurisdictional operations during the test year was $4,465,702. Using the adjusted capital structure allowed, the Commission has computed an interest expense reduction of $172,469, which results in an increase to income tax expense of $68,029.

Storm Damages

ULH&P proposed an adjustment of $6,934 to increase its expenses for storm damages to reflect the 10-year average expense. The adjustment was calculated using the June 1991 Consumer Price Index-Urban ("CPI-U") to adjust the recorded dollar amount to July 31, 1991. Such an adjustment is consistent with the Commission's decisions in previous ULH&P rate cases; however, the Commission believes that it is more appropriate to use the July 1991 test-year end CPI-U. The Commission has recalculated the adjustment using the appropriate CPI-U for the test year and has determined that operating expenses should be increased $7,075.

Injuries and Damages

ULH&P proposed an increase of $57,080 to its expenses for injuries and damages to reflect the 10-year average expense. The adjustment was calculated using the same methodology as had been used in the adjustment for storm damages. Because the Commission believes it is more appropriate to use the test-year end CPI-U for July 1991, we have recalculated the proposed adjustment, increasing operating expenses by $57,313.

<u>Postage Expense</u>

ULH&P proposed an increase of $17,731 to its operating expenses to reflect postage rate increases effective February 3, 1991 on an annual basis. ULH&P computed the increase by annualizing the cost of the test-year level of mail and then subtracting the actual mailing costs which reflected the period from February 3 through test-year end.

The Commission cannot accept the adjustment as proposed by ULH&P. In performing its calculations, ULH&P ignored the postage costs which were incurred at the old rates from the beginning of the test year until February 2, 1991. In effect, this adjustment contains a double count of postage expense for 6 months of the test year. We therefore reject the proposed adjustment.

The Commission also notes that the majority of mailings included in the proposed adjustment related specifically to ULH&P, such as customer bills and first class letters. ULH&P has indicated that its costs for these items are allocated to ULH&P by CG&E. The Commission does not believe it is appropriate for such mailing costs to be allocated when they should reflect direct charges. Customer bills and other ULH&P mailings must be specifically identified and directly charged to ULH&P's accounts rather than allocated.

Advertising Expenses

ULH&P proposed an adjustment to reduce operating expenses by $127,821 to reflect the elimination of institutional advertising as required by 807 KAR 5:016, Section 4. The charges eliminated represented the test-year-end balances of Account No. 913, Advertising Expenses, and Account No. 930.1, General Advertising Expenses. While making the adjustment in compliance with the regulation, ULH&P claimed that these expenses are necessary, recoverable business expenses, and should not be eliminated.[61] This position is the same one taken by ULH&P in Case No. 90-041.

In addition to ULH&P's adjustment, the AG proposed to remove the following additional expenses:

Customer Service & Information:	
Account No. 907 - Supervision	$ 69,211
Account No. 908 - Customer Assistance Expenses	766,201
Sales:	
Account No. 911 - Supervision	20,371
Account No. 912 - Demonstrating and Selling Expenses	171,110
Total	$1,026,893

The amounts for Accounts No. 907, 911, and 912 represent the entire test-year charges. The AG contends that these expenses are not appropriate for inclusion in rates because they reflect a massive effort by ULH&P to market its product without any cost justification.[62]

61 Bruegge Direct Testimony, page 13.

62 DeWard Direct Testimony, page 24.

The Commission has been able in this proceeding to review with greater detail the advertising expenses of ULH&P than was available in Case No. 90-041. Some of the expenses recorded in Account No. 912 appear to be promotional in nature and are not allowable under 807 KAR 5:016. In addition to the advertising expense adjustment proposed by ULH&P, the Commission has reduced operating expenses by $66,779. This amount reflects the test-year charges to Account No. 912-40, Regional Marketing - Central Division; Account No. 912-41, Regional Marketing - Southern Division; Account No. 912-42, Regional Marketing, Planning & Community Development; and $5,833[63] in other specific Account No. 912 transactions.

AFUDC

ULH&P proposed an increase in revenues of $735,395 to reflect its annualization of AFUDC related to construction work in progress ("CWIP") subject to AFUDC as of test-year end. ULH&P computed its adjustment taking the electric CWIP subject to AFUDC and multiplying that amount by the AFUDC rate of 9.5 percent.[64]

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63 $3,472 - Dektas & Eger, Inc., trade magazine ads; $1,499 - Associated Premium Corp., jar openers; and $862 - Community Profiles.

64 Response to the Commission's Order dated November 14, 1991, Item 33, page 43 of 43.

The AG proposed to remove ULH&P's book taxes associated with AFUDC, stating that without such an adjustment, tax expenses would be duplicated because of ULH&P pro forma adjustment.[65]

The methodology followed by ULH&P closely parallels that used by the Commission in determining an AFUDC offset to net operating income. However, ULH&P's approach used the AFUDC rate instead of the overall rate of return on capital and did not adjust the increase for the test-year-end electric balance in Account No. 432, AFUDC - Credit. An AFUDC offset adjustment consistent with previous ULH&P cases results in a more reasonable overall rate of return. ULH&P's net operating income is increased by $629,478 to reflect pro forma AFUDC of $782,361[66] for rate-making purposes.

Demand Side Management ("DSM") Incentive Payment

The AG proposed to remove a test-year incentive payment of $38,025 made by ULH&P relating to a customer's installation of a thermal energy storage system. The AG indicated that the installation was not completed during the test year, and there were no offsetting benefits associated with reduced demand or reductions in allocated costs. Therefore, in his view, it was inappropriate to include this cost for rate-making purposes.[67]

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65 DeWard Direct Testimony, page 31.

66 $7,741,000 times 10.107% = $782,361.

67 DeWard Direct Testimony, page 25.

When asked if the test-year level of expense for all DSM activity reflected the normal, ongoing level of expense, ULH&P could not indicate whether the level would be higher, lower, or the same.[68]

The Commission realizes that ULH&P's DSM involvement is in its early developmental stages. The Commission encourages ULH&P in its DSM efforts. However, it must be displayed that some indication of expected ongoing levels of activity or similar incentive payments will be a recurring DSM expenditure. Operating expenses have been reduced by $38,025.

<u>Hartwell Recreation Center ("Hartwell")</u>

The AG proposed to reduce operating expenses $30,759 for operation and maintenance and rental charges associated with Hartwell, which is owned by CG&E. The AG stated that the Commission had removed similar expenses in Case No. 90-041 and that there was no reason to reverse that decision given the current economic situation.[69]

ULH&P indicated that the facility was used for training programs, recreational programs, and employee gatherings such as the annual Christmas party. While ULH&P stated that there were benefits to the ratepayers in having Hartwell, it could not quantify those benefits.[70]

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[68] T.E., Vol. III, March 19, 1992, page 183.

[69] DeWard Direct Testimony, page 26.

[70] T.E., Vol. II, March 18, 1992, pages 149 through 152.

We do not believe the costs to maintain recreation centers should be included for rate-making purposes. While these expenses may benefit employer/employee relations, the ratepayers should not bear these costs. Operating expenses have been reduced by $30,759.

Special Programs

The AG proposed to remove from operating expenses $39,019 related to numerous management training, assessment, and enhancement programs. The AG stated that given the current economic conditions, such programs were not needed to motivate ULH&P employees. The AG also argued that any incurred costs from these programs should be offset by future efficiencies.[71]

In order to be effective, a utility may need to undertake numerous types of training programs. Current economic conditions do not necessarily represent a positive motivating force to encourage a workforce. No adjustment is required.

Edison Electric Institute ("EEI") Dues

The AG proposed to remove $50,993 from operating expenses for EEI membership dues. The AG stated that EEI is an electric utility lobbying organization, whose primary interest is protection of shareholders.[72]

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71 DeWard Direct Testimony, pages 26 through 28.

72 Kinloch Direct Testimony, pages 62 through 65.

ULH&P indicated that it had not performed any cost/benefit analysis for the EEI dues. Further, ULH&P could not identify any specific benefits it or its ratepayers received from membership.[73]

The Commission is familiar with EEI and aware of the nature of its activities. We have excluded EEI membership dues in other rate proceedings when ratepayer benefit could not be demonstrated. Given the nature of EEI and ULH&P's lack of demonstrating ratepayer benefit of membership, the Commission has removed from operating expenses the allocated membership dues of $50,993.

<u>Electric Power Research Institute ("EPRI") Membership Dues</u>

The AG proposed a reduction in operating expenses of $601,136 for ULH&P's allocated share of membership dues in EPRI. The AG noted that ULH&P had not performed any cost/benefit analysis of its membership. The AG stated that since ULH&P was a distribution utility, the majority of EPRI research was of no direct benefit to ULH&P's ratepayers.[74]

As with EEI, the Commission is aware of the nature of EPRI's activities. We recognize that EPRI is a research organization funded by membership dues paid by member utilities. Applied EPRI research in generation, transmission, and distribution fields should be of benefit to ULH&P and its ratepayers, regardless of whether ULH&P is a generator or distributor. No adjustment is required.

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73 T.E., Vol. III, March 19, 1992, pages 184 and 189.

74 Kinloch Direct Testimony, pages 67 and 68.

Hay Associates

During the test year, ULH&P was allocated $1,731 in expenses related to Hay Associates.[75] Hay Associates performs annual reviews of ULH&P's and CG&E's salary structure.[76] ULH&P has indicated that Hay Associates does not submit written reports of its analysis.[77] While Hay Associates does maintain a utility salary data base, ULH&P also indicated that a significant amount of salary information used in the annual evaluation of salary structure was maintained in-house.[78] It is not clear what the function of Hay Associates is, and ULH&P has not adequately documented the benefit from the services provided by Hay Associates. Operating expenses are reduced by $1,731 to exclude this expense for rate-making purposes.

Employee-Related Expenses

The AG proposed to reduce expenses by $42,625 for items recorded in Account No. 926, Employee Pensions and Benefits. The AG stated that these expenditures represented inappropriate costs to include for rate-making purposes.[79] ULH&P responded that the

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75 Response to Staff Hearing Data Request No. 8.

76 Response to the Commission's Order, dated January 17, 1992, Item 68(d).

77 Id., Item 68(a).

78 T.E., Vol. IV, March 20, 1992, pages 115 through 117.

79 DeWard Direct Testimony, page 25.

charges to Account No. 926 were necessary to maintain good employee morale, which translated into good customer service.

As shown in Appendix D, expenses for employee picnics, children's Christmas parties, and charitable fund-raisers should not be included for rate-making purposes, reducing operating expenses by $2,572.

Miscellaneous Expenses

The AG proposed to reduce expenses by $65,142. This amount included $12,258 for a Christmas train display in CG&E's main office and $52,884 in miscellaneous expenditures. The AG argued that the train display only promoted the image of CG&E and had nothing to do with providing reliable electric service. The AG stated that the other miscellaneous expenses included items previously disallowed in Case No. 90-041 and expenses which appeared to have been misclassified as operating expenses rather than properly as donations.[80]

ULH&P claimed that the AG's adjustment eliminates expenses which are responsible for the efficient and reliable services provided by it to the community. ULH&P believes that these expenses are reasonable and necessary and should not be eliminated.[81]

80 DeWard Direct Testimony, pages 28 through 30.

81 Lonneman Rebuttal Testimony, page 11.

It appears that several expenses that ULH&P has recorded on its books as operating expenses should have been recorded in Account No. 426.1, Donations. Several miscellaneous expenses identified by the AG are expenses we have disallowed in previous rate cases. The Commission has also identified other expenses that are not appropriate for rate-making purposes, including non-recurring items. A listing of the disallowed expenses totalling $69,032 is included in Appendix D. ULH&P shall review its accounting treatment of sponsorships and community programs and bring that treatment into compliance with the USoA's definition of Account No. 426.1.

The Commission, after consideration of all pro forma adjustments and applicable income tax effects, has determined ULH&P's adjusted net operating income to be as follows:

Operating Revenues	$148,824,021
Operating Expenses	153,832,122
AFUDC Offset	629,478
Net Operating Income	$(4,378,623)

RATE OF RETURN

Capital Structure and Debt Cost

ULH&P proposed to use its capital structure as of July 31, 1991 adjusted to include short-term debt and deferred investment tax credits.[82] The proposed capital structure included 48.80

82 Mosley Direct Testimony, page 5.

percent long-term debt, 3.21 percent short-term debt, and 47.99 percent common equity.[83] ULH&P's long- term debt component was based on the carrying value of debt. The AG proposed to base long-term debt on the outstanding principal amount. The AG's position was that this method more accurately states the true liability of the company and is supported by return on rate base regulatory theory.

ULH&P's use of the carrying value is more appropriate. The carrying value reflects the unamortized debt discounts, premiums, and expenses at the date of calculation. This adjusted value more closely matches the current booked costs to ULH&P as opposed to the ultimate liability, and it is the booked costs that are appropriate to use in setting rates.

The cost of capital should be based on ULH&P's actual capital structure at July 31, 1991 consisting of 46.94 percent long-term debt, 7.11 percent short-term debt, and 45.95 percent common equity.

ULH&P proposed cost of long-term debt of 9.38 percent and cost of short-term debt of 7.58 percent based on an embedded cost of 9.27 percent as of July 31, 1991.[84] ULH&P updated its embedded cost of debt to December 31, 1991 reflecting long- term debt cost

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83 Calculated from ULH&P Exhibit JRM, pages 1-2, filed November 18, 1991.

84 Calculated from ULH&P Exhibit JRM, page 2, filed November 18, 1991.

of 9.375 percent and short-term debt cost of 5.935 percent.[85] Consistent with his recommendation on the debt component of capital structure, the AG calculated the cost of debt using average yield and yield to maturity. Consistent with ULH&P's determination of the debt component of capital structure its debt cost was calculated using interest expense less current amortization of debt discounts, premiums and expenses. As ULH&P's calculation more closely matches booked cost, we find the cost of long-term debt to be 9.375 percent and the cost of short-term debt to be 5.935 percent.

Return on Common Equity

ULH&P proposed a return on equity ("ROE") of 13.7 to 14.2 percent in its application.[86] ULH&P later determined its cost of common equity to be in the range of 13.4 to 13.9 percent.[87] The AG proposed the cost of common equity to be within the range of 10.25 to 11.25.[88]

To arrive at its requested return, ULH&P performed a discounted cash flow ("DCF") analysis and a risk premium analysis.

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85 Calculated from Revised ULH&P Exhibit JRM, page 2, filed March 17, 1992.

86 Mosley Direct Testimony, page 23.

87 T.E., Vol. I, March 17, 1992, page 125.

88 Weaver Direct Testimony, page 38.

For its DCF study ULH&P developed a proxy group of publicly traded utility companies to estimate its cost of equity as if it were a publicly traded independent company. ULH&P selected its proxy from combined gas and electric utilities reported in Value Line with bond ratings equivalent to ULH&P (BBB). ULH&P believes the proxy group is viewed by the financial community and investors as comparable risk companies.[89]

The DCF formula used by ULH&P reflects quarterly compounding of dividends and a 3.5 percent flotation cost adjustment.[90] ULH&P calculated an historical dividend growth rate of 6.7 percent for the period 1986-1990 and a projected dividend growth rate of 4.3 percent for 1994-1996. ULH&P concluded that a 5 percent growth rate is reasonable based on past and projected performance.[91] Based on stock prices for the 12 months ended February 29, 1992, ULH&P's DCF analysis produced a required ROE of 13.4 percent.[92] ULH&P concluded that it was more risky than its proxy and added a premium of 50 basis points to its DCF results to compensate for the difference in risk.[93]

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89 T.E., Vol. I, March 17, 1992, page 170.

90 *Mosley Direct Testimony, page 10.*

91 Id., page 17.

92 Revised ULH&P Exhibit JRM, page 4, filed March 17, 1992.

93 Mosley Direct Testimony, page 20.

ULH&P's risk premium analysis was based on a study by the Financial Analysts Research Foundation (updated by Ibbotson Associates, Inc.) on total rates of return for common stocks and bonds and the difference in average annual returns for the period 1926-1990. The study indicated an historical equity-debt risk premium of 4.9 percent.[94] To this, ULH&P added the current yield on its BBB rated bonds of 9.3 percent to arrive at a return on equity of 14.2 percent. ULH&P concluded that this result substantiates its DCF analysis.[95]

To perform a DCF analysis, the AG selected six companies he considered to be comparable to ULH&P. The AG determined his proxy group as combination gas and electric companies reported in Value Line with over 50 percent of revenues from electric and no nuclear facilities.

The AG averaged historical and forecasted rates to arrive at a growth rate of 3.25 to 4.25 percent for use in his DCF study. Based on stock prices for the period from October 18, 1991 - January 17, 1992 and adjusted for a 3.5 percent flotation cost adjustment, the AG's DCF study resulted in a cost of equity for ULH&P in the range of 9.86 to 10.92 percent.[96] Acknowledging an increased cost of equity to ULH&P due to lower interest coverage

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94 Id., page 18.

95 Id., page 19.

96 Weaver Direct Testimony, page 37.

than the comparable companies, the AG added a risk adjustment to arrive at his ultimate conclusion that the cost of equity to ULH&P is between 10.25 and 11.25 percent.[97]

Use of the quarterly dividend model for ULH&P's DCF analysis is inappropriate because investors would be doubly compensated.

ULH&P and the AG both proposed a 3.5 percent flotation cost adjustment in this case. ULH&P's adjustment was on the belief that a flotation cost adjustment is proper regardless of whether or not a new stock issuance is planned.[98] The AG's adjustment was on the belief of an expected need for external financing to fund ULH&P's construction budget over the next five years.[99]

ULH&P provided an analysis of flotation cost for its parent CG&E during the past 10 years and arrived at an average actual flotation cost of 3.57 percent.[100] Excluded from this average was a "bought" deal in which issuance cost were substantially lower than usual according to ULH&P. Stock may be issued through numerous means and the Commission does not believe the costs associated with a private placement should be excluded from an evaluation of actual cost. The AG merely accepted ULH&P's figure.[101]

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97 Id., page 36.

98 Mosley Direct Testimony, page 11.

99 Weaver Direct Testimony, page 35.

100 ULH&P Exhibit JRM, page 5, filed November 18, 1991.

101 Weaver Direct Testimony, page 36.

ULH&P would have the Commission believe that all of its equity capital is the result of public stock offerings; however, equity investment made by CG&E could come from other sources, such as CG&E's internally generated funds or debt.[102] The flotation cost adjustment should not be allowed because it overstates ULH&P's required return on equity. The percentage is not truly reflective of cost to CG&E and applicability to ULH&P.

The Commission has traditionally used the DCF model to assess comparable companies rather than companies of comparable risk. The two are not altogether in conflict. There is merit to comparable risk, in fact this would often be one of the selection criteria for comparable companies. ULH&P and the AG both used a mixture of historical and forecasted rates to determine growth. There is no compelling evidence that investors expect historical trends to continue into the future. A premium is not essential to account for ULH&P's greater risk relative to its proxy. If the proxy is truly of comparable risk then no additional adjustment is necessary.

The Commission has for a number of years considered the risk premium method for determining cost of common equity to be unreliable because it is subject to significant fluctuations due to the volatility of the bond and stock markets. The AG also disagreed with ULH&P's use of the risk premium method.

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[102] Id., page 35-36.

Considering all factors, the risk premium study should not be utilized in this case.

The Commission affirms its traditional use of the DCF model to estimate ROE and continues to believe that the DCF method cannot be applied in a pure mechanistic manner. Considering all of the evidence, including current economic conditions, we find that the cost of common equity is within a range of 11.0 percent to 12.0 percent. Within this range, an ROE of 11.5 percent will best allow ULH&P to attract capital at a reasonable cost, maintain its financial integrity to ensure continued service and to provide for the necessary expansion to meet future requirements, and also result in the lowest possible cost to ratepayers.

Rate of Return Summary

Applying the rates of 9.375 percent for long-term debt, 5.935 percent for short-term debt, and 11.5 percent for common equity to the capital structure produces an overall cost of capital of 10.11 percent, which we find to be fair, just, and reasonable. This cost of capital produces a rate of return on ULH&P's jurisdictional net original cost rate base of 9.80 percent which the Commission finds is fair, just, and reasonable.

REVENUE REQUIREMENTS

ULH&P needs additional annual operating income of $13,375,933 to produce a rate of return of 11.5 percent on common equity based on the adjusted historical test year. After the provision for state and federal taxes, PSC Assessment, and increased uncollectibles, there is an overall revenue deficiency of $22,334,942 which is the amount of additional revenue granted.

The net operating income necessary to allow ULH&P the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $8,997,310. The required operating income and the increase in revenue allowed herein is as follows.

Net Operating Income Found Reasonable	$ 8,997,310
Adjusted Net Operating Income	(4,378,623)
Net Operating Income Deficiency	13,375,933
Gross Up Revenue Factor for Taxes, PSC Assessment, and Uncollectibles	1.66979
Additional Revenue Required	22,334,942

The additional revenue granted will provide a rate of return on the jurisdictional net original cost rate base of 9.80 percent and an overall return on total electric capitalization of 10.11 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $171,158,963.

PRICING AND TARIFF ISSUES

Cost-of-Service Studies

ULH&P and the AG both filed fully-allocated embedded cost-of-service studies for the year ending July 31, 1991. The assumptions and methodologies used by the two parties in developing the studies differ significantly, which explains the disparity that exists in the results of the studies.

The results of ULH&P's study indicate a significant variation in the contribution each class makes to the overall electric system rate of return of 10.28. The class rates of return as determined by ULH&P are as follows: Residential, 5.14; Distribution, 27.12; Transmission, 4.07; Lighting, 28.69; and Other, 41.27.[103] This study indicates that the Residential and Transmission classes are contributing less toward the system rate of return than the other classes.

The AG's study showed the following class contributions to the overall electric system rate of return of 10.28: Residential, 14.91; Distribution, 9.49; Transmission, -59.19; Lighting, 11.59; and Other, 38.67.[104] This study indicates that the Distribution and Transmission classes are contributing less than the other classes toward the system rate of return.

ULH&P used a 12 coincident peak ("12-CP") demand allocation factor to allocate demand-related production and transmission costs to customer classes. Under this method, all such costs are allocated to customer classes on the basis of each class's contribution to the 12 monthly maximum system peaks. The 12-CP method, like other peak demand methods, is predicated on the assumption that a utility's investment in production plant is determined only by system peak demands.

ULH&P divides distribution costs into demand-related and customer-related components by using percentages supposedly

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103 Van Curen Testimony, Exhibit PVC-ECOS, Schedule 1.

104 Kinloch Testimony, Exhibit DHK-6, Page 1 of 19, Schedule 1.

determined in a minimum-intercept study performed in a previous case.[105] Using this criteria, ULH&P classifies 80 percent of distribution costs as demand-related and 20 percent as customer-related. Demand-related distribution costs are then allocated on the basis of a class's non-coincident peak demand. Customer-related distribution costs are allocated based on the number of distribution customers. Various other plant and expense allocation factors were also used by ULH&P.

The AG allocated demand-related production and transmission costs using a variation of the average and excess method. This method recognizes that a portion of a utility's production plant is determined by durational or energy loads. The average and excess method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak demands.[106] The AG describes his allocation methodology as follows: "The amount of capacity associated with the average load is based on each class's contribution to the average load. The excess capacity above the average is allocated using ULH&P's 12 CP method."[107]

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105 ULH&P's Response to Item 73 of the Commission's Order dated December 17, 1991.

106 National Association of Regulatory Utility Commissioners' ("NARUC") "Electric Utility Cost Allocation Manual," revised in January 1992, page 49.

107 Kinloch Testimony, page 36.

In addition to the demand allocator, the AG modified three other allocators used by ULH&P. The first is ULH&P's allocator K414, which is used to allocate certain costs related to distribution plant. This allocator classifies 80 percent of distribution costs as demand-related and 20 percent as customer-related. The AG argued that distribution plant should be separated into primary and secondary components. ULH&P does not separate distribution plant in this manner. The AG maintains that the primary component should be allocated on the basis of system non-coincident peak, while the secondary component should be allocated on the basis of the summation of individual non-coincident peaks.[108] Using ULH&P's assumption that 80 percent of distribution costs are demand-related and 20 percent are customer-related, the AG allocated over three-fourths of the demand portion--the primary component--using his allocator A202 (average and excess at distribution). The remaining portion of demand-related distribution costs--the secondary component--are allocated using ULH&P's allocator K202 (total non-coincident KW).

Secondly, the AG modified ULH&P's administrative and general allocation factor K410. The AG claimed that a more accurate method of allocating these costs is based on the portion of other operating and maintenance expenses assigned to each class, less purchased power and fuel costs. Lastly, the AG modified ULH&P's allocator K206 (PSCKY net distribution plant less account 106) to

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108 Id., page 38.

reflect his allocation of distribution costs. The AG also modified several allocators assigned to individual plant and expense items.

The Commission finds numerous deficiencies in both cost-of-service studies presented in this case. In ULH&P's study, a 12-CP demand allocator is developed for the test year ending July 1991 by using load research and other data from time periods other than the test year. In fact, the most recent data used in developing the 12-CP demand allocation factor is from the year ending October 1990. Some of the data used in the development of this allocation factor is as much as 11 years old. In total, data from at least four different time periods, ranging from 1980 to 1990, are used in this calculation. The NARUC cost allocation manual states that the minimum data requirement for the 12-CP demand allocation method is reliable monthly load research data for each class of customers and for the total system.[109] As numerous variables, such as weather, economic factors, and appliance stocks and efficiencies fluctuate over time periods, it is very unlikely that data from so many different time periods is either reliable or representative of current conditions and, therefore, should not be used to calculate an allocation factor in this case.

[109] NARUC's "Electric Utility Cost Allocation Manual," revised in January 1992, page 46.

ULH&P did not perform a minimum-intercept or zero-intercept study in this case in order to divide distribution costs into demand-related and customer-related components. When asked how it determined the percentages of demand-related and customer-related distribution plant, ULH&P claimed to have performed a minimum-intercept study.[110] However, ULH&P could not determine when such a study was performed.[111] The Commission has determined that ULH&P did not perform a minimum-intercept or zero-intercept study in Case No. 90-041[112] and cannot determine whether ULH&P performed such a study in Case No. 9299[113] (the rate case preceding Case No. 90-041). Even if such a study was performed in Case No. 9299, it is doubtful that the results of the study, which depend on current and detailed distribution plant and cost data, would still be reliable, as that case was decided in October 1985.

The AG criticizes ULH&P's failure to divide distribution plant into primary and secondary components and to allocate each component using separate allocation factors. ULH&P claims that it

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110 ULH&P's Response to Item 73 of the Commission's Order dated December 17, 1991.

111 T.E., Volume II, page 141.

112 Case No. 90-041, An Adjustment of Gas and Electric Rates of the Union Light, Heat and Power Company.

113 Case No. 9299, An Adjustment of Electric Rates of The Union Light, Heat and Power Company.

does not maintain its accounting records in that manner as such a separation of distribution costs into primary and secondary components is not required by the USoA established by the Federal Energy Regulatory Commission.[114] NARUC states that "in order to recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications."[115] The Commission believes that, given the distinct voltage characteristics of distribution facilities, a separation of certain distribution costs into primary and secondary components is appropriate and necessary. ULH&P should begin separating distribution facilities into primary and secondary components for use it its next cost-of-service study.

The AG's cost-of-service study presents its demand allocation methodology as an "average and excess" method. However, as pointed out by ULH&P, the AG's calculation of this allocation factor differs significantly from that prescribed by the NARUC in its "Electric Utility Cost Allocation Manual."[116] The AG admitted

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114 T.E., Vol. II, page 140.

115 NARUC's "Electric Utility Cost Allocation Manual," revised January 1992, page 89.

116 ULH&P's Brief, pages 26-27.

that the NARUC method did not achieve the results he wanted, so he modified it according to his own assumptions and judgment.[117] The modifications made by the AG to the average and excess methodology are inconsistent with the methodology prescribed by NARUC and are inappropriate for the allocation of production and other demand-related costs.

Distribution costs should be separated into primary and secondary components. NARUC considers such a division of distribution costs necessary and other utilities presenting cost-of-service studies before this Commission have made such a bifurcation. However, partly because of unavailable data from ULH&P, the AG divides these costs by using percentages found to be appropriate by Louisville Gas and Electric Company ("LG&E") and Kentucky Power Company ("KPC") in recent rate cases.[118] It is unreasonable to assume that the primary and secondary split in LG&E's and KPC's distribution plant is at all similar to that of ULH&P. The make-up of each utility's distribution plant is unique and cannot be used as a proxy for another utility.

The AG used and modified several of the allocation factors developed by ULH&P in its cost-of-service study. Some of these factors have been improperly calculated by ULH&P, infra. The AG's use of these improper factors renders the AG's calculations

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117 AG's Response to Item 10 of ULH&P's Information Request dated February 10, 1992.

118 T.E., Vol. V, March 23, 1992, page 98.

inappropriate. The most obvious cases are the AG's use of ULH&P's 12-CP demand allocation factor (K200) in the calculation of the AG's average and excess allocator and the use of ULH&P's division of distribution plant as 80 percent demand-related and 20 percent customer-related in the AG's calculation of primary and secondary distribution plant components.

The Commission finds that both cost-of-service studies presented in this case are inappropriate, unreliable and should be rejected.

The Commission is aware of the on-going debate regarding the appropriate methodologies to be used to allocate demand-related plant and expense items. In cost-of-service studies presented in this case, ULH&P advocated the use of a 12-CP demand method while the AG used a modified "average and excess" method. The 12-CP demand method belongs to the family of peak demand methods, while the average and excess method is a type of energy weighting method.

The most fundamental difference between these two methodologies is the way in which a utility's investment in production plant is viewed. Proponents of a 12-CP or other peak demand method claim that a utility's production plant is built only for the purpose of serving peak load, whether individual monthly peaks or the annual system peak. Thus, all demand-related production costs must be allocated to customer classes on the basis of each class's contribution to the system peak. Under this scenario, if a customer class, such as street lighting, does not use the system at the time of system peak, no production costs would be allocated to it. Proponents of an average and excess method or some other energy weighting method claim that a utility's production plant is built not only to serve peak demand but also to serve off-peak base load. For this reason, all classes should bear some of the costs of producing electricity regardless of a class's use of the system at the time of system peak. There are also time-differentiated methodologies such as the Base-Intermediate-Peak ("BIP") method that allocate production plant costs to off-peak baseload hours, intermediate "shoulder peak" hours, and peak hours. ULH&P and other interested parties may want to refer to the description of these methodologies as set forth in the NARUC's "Electric Utility Cost Allocation Manual" which was revised in January 1992.

Over the years, the Commission has accepted cost-of-service studies that used demand allocation methodologies from each of these different categories. There are convincing arguments that can be made for any of these methods. For this reason, the Commission recommends that, in future rate cases, ULH&P file multiple cost-of-service studies that use, among other things, demand allocation methods from each of the peak demand, energy weighting, and time-differentiated families of production plant allocation methodologies. To the extent possible, intervenors should also present multiple cost-of-service studies using various methodologies. By having multiple cost-of-service studies presented in rate cases, the Commission is convinced that a more reasonable and informed decision can be made regarding the appropriate allocation of revenue to customer classes.

Revenue Allocation

Based on the results of its cost-of-service study, ULH&P proposed to allocate its requested increase as follows: 24.7 percent to the residential class; 16.7 to 18.9 percent to the commercial and industrial classes; and approximately 10.3 percent to its lighting classes. The AG, based on his cost-of-service study and assuming the full increase was granted, proposed 19 to 20 percent increases for residential and commercial customers, an approximate 30 percent increase for industrial customers, and an approximate 10 percent increases for ULH&P's lighting class customers.

Inasmuch as the Commission has rejected both of the proposed cost-of-service studies neither study will be used to allocate the revenue increase. The increase will be allocated to ULH&P's customer classes in the same proportions each class currently contributes to ULH&P's total electric revenues. This approach, which is traditionally utilized when no cost-of-service study has been presented, maintains the existing allocation between classes and results in each class receiving approximately the same overall percentage increase. In this instance, all classes will receive increases of approximately 15 percent.

Residential Rate Design

The AG proposed that ULH&P's residential rates, which consist of a flat summer rate and a two-step declining block winter rate, be restructured to include inverted (inclining block) rates both in summer and winter. While the first step of the existing winter rate encompasses 0 to 1,000 KWH, the AG would have the first step of the two-step rate cover only 0 to 700 KWH. Based on his analysis of ULH&P's monthly power costs, the AG opined that, under ULH&P's existing rate structure, temperature-sensitive power is being underpriced and customers are being encouraged to overuse or waste energy, resulting in higher costs for all customers.

ULH&P opposed the AG's proposal arguing that reducing the first block to 700 KWH would be cutting into non-temperature sensitive loads and would be punitive to its all-electric customers. ULH&P contends that its existing winter rate design, with the break point at 1,000 KWH, properly recognizes its all-electric customers usage patterns and should not be changed absent end-use data which would support such a change. ULH&P also contested the AG's determination of baseload costs and temperature-sensitive load costs, two components in the AG's calculation of inverted rates.

The AG's proposal has some merit in light of ULH&P's summer load characteristics. ULH&P's cooling load is the primary force driving its predominant summer peak while it experiences its heating load during its off-peak (winter) season. The Commission recognizes that increased off-peak demands can produce many of the same benefits as reduced on-peak demands, such as improved system load factor and lower unit costs. Given these circumstances, the Commission finds that ULH&P's residential rates should be modified to include an inverted block summer rate but should retain a declining block winter season rate. The Commission shares ULH&P's concerns about reducing the break point in its residential rate schedule without the benefit of end-use data and, therefore, will maintain the existing break point of 1,000 KWH. We are, however, interested in pursuing this matter further in ULH&P's next general rate case. ULH&P shall address the appropriate structure of its residential rates in that case. In keeping with our stated goals of gradualism and rate continuity, the Commission will take a moderate approach to implementing an inverted summer rate by increasing the second rate block by approximately one-and-one-half times the increase to the first block.

Bad Check Charges

ULH&P proposed to increase from $8 to $15 its charge for receiving and processing bad checks to serve as a deterrent to customers that might issue such checks. ULH&P indicated the proposed charge was comparable to the charges assessed by local businesses and financial institutions.

The AG opposed the increase, claiming that publicizing the existing charge would serve as a more effective deterrent than increasing the charge by 87 percent. The AG argued that the proposed charge is not cost based and that any increase should be limited to the level of the overall increase granted in this case.

ULH&P has not provided sufficient cost support to justify the requested $7 increase in the bad check charge. Customers must be aware of the charge before it can become an effective deterrent. In the absence of cost support, the charge should remain at $8.

Late Payment Charges

The AG proposed that the Commission direct ULH&P to change the way in which it credits partial payments from customers carrying a past-due balance from a previous month. The proposal would require that, when a customer pays enough to cover the current month's bill plus at least $5 toward the past-due balance, the payment should first be credited to the current month's bill rather than to the customer's oldest balance first. The AG argued that such a change was needed to eliminate the practice of a customer paying late payment charges month after month when the customer wasn't late in paying his bill but was merely unable to pay the full amount of his current bill and his past-due balance.

ULH&P opposed the proposal arguing that the AG was wrong in claiming that a customer could pay a late payment charge on the same balance month after month under the existing late payment provision. ULH&P contends that a late payment charge is applied to a past due balance only once under its current procedure.

The Commission is persuaded to adopt the AG's proposal. The proposal will apply only when the customer pays his current month's bill in full and makes a contribution of at least $5 toward his past due balance. While leaving intact ULH&P's late payment provision, the proposal will remove the customer's disincentive for making a timely partial payment by eliminating the recurrence of a late payment charge.

Rate and Tariff Changes

ULH&P proposed few structural changes to its existing rates or tariff schedules. ULH&P did propose to modify its electric space heating tariff, Rate EH, an optional rate for non-residential customers having a demand of less than 500 KW. The modification would remove the rate's limitation to customers receiving similar service prior to June 25, 1981. ULH&P proposed to add a second step to Rate GS-FL for general service fixed loads of less than 540 hours use per month. ULH&P also proposed to add a rate step for traffic lighting service to cover situations where company personnel provide limited maintenance for traffic signal equipment but energy is supplied from a separately-metered source. On its outdoor lighting schedule, Rate OL, ULH&P proposed to delete and add various lighting units and to give customers the option of making a one-time up-front contribution for a decorative unit in order to reduce the regular monthly charge to that of a standard unit. On its non-standard private lighting schedule, Rate NSP, ULH&P proposed to limit the availability of some units to those customers served at the time this application was filed.

The changes described above and other text modifications proposed by ULH&P were not contested by any party. The Commission has reviewed these changes and finds they should be approved with the exception that the limitations on Rate NSP shall be prospective from the effective date of this Order. The new rate steps and new lighting units are set out in Appendix A. The text changes are not included in the Appendix.

MANAGEMENT AUDIT

General

In its final Order in Case No. 90-041, the Commission expressed several concerns with ULH&P's response to the 1989 management audit performed by Schumaker & Company. The Commission clearly stated that it found it appropriate to review ULH&P's audit-related activities in formal rate case proceedings. In addition, the Commission stated that it considered the audit report "to constitute substantial evidence regarding potential cost savings measures available"[119] to ULH&P and also clearly indicated that adjustments related to the management audit recommendations may be considered in future rate proceedings.

In this proceeding, ULH&P initially provided a schedule of test-year costs and benefits attributable to the implementation of management audit recommendations.[120] That schedule reflected "Per Auditor" and "Per Company" costs and benefits for 53 recommendations. In response to a request for specific detailed information relating to the schedule, ULH&P indicated that a schedule with the information and level of detail requested did not exist.[121] ULH&P subsequently disclosed that there were several errors in that schedule, and that it does not have the accounting mechanisms in place to specifically identify allocated individual recommendation costs in the test year.[122] ULH&P has also stated that creating and maintaining a special detailed reporting system to track the success of implemented management audit recommendations would be prohibitively expensive and a waste of manpower and resources.[123]

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119 Id., page 76.

120 Response to the Commission's Order dated November 14, 1991, Item 49.

121 Response to the Commission's Order dated December 17, 1991, Item 63.

122 Response to the Commission's Order dated January 17, 1992, Item 47.

123 Id., Item 48.

However, in a December 1991 summary report of ULH&P's implementation progress prepared by the Commission's Management Audit Branch, which was reviewed by ULH&P prior to publication, 11 recommendations with a net savings or cost avoidance of $987,400 to $995,400 were identified as being implemented. Four recommendations with an identified savings of $803,000 were directly related to the Electric Operations Department and four recommendations with an identified savings of $52,900 to $60,900 were in the Customer Service or Administrative services area and were indirectly related to Electric Operations.[124] The amounts included in the summary report were derived from ULH&P's progress reports submitted to the Management Audit Branch as part of the management audit follow-up process.

If such information can be provided in regular periodic reports to the Commission's Management Audit Branch but cannot be addressed with any certainty in a rate proceeding, the Commission must not only question the accuracy of the savings identified by ULH&P in its periodic progress reports but also the intentions of ULH&P to follow through on its actions to achieve these savings.

While recognizing that savings and efficiency enhancements are not always represented by actual reductions in current dollars

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124 Summary Report: The Union Light, Heat And Power Company's Progress In Implementing The Management Audit Recommendations, dated December 1991.

but may also represent future avoided costs, the Commission believes that successful implementation of reasonable and appropriate audit recommendations provides benefits to both ULH&P's customers and shareholders. The customers benefit to the extent that increased productivity and efficiency allow ULH&P to meet its service obligations more economically. This, in turn, benefits the owners by enhancing ULH&P's ability to earn its authorized rate of return.

As audit recommendations are implemented, the Commission fully expects ULH&P to provide appropriate cost/benefit analyses supporting its efforts in the periodic progress reports and, when requested, in rate proceedings. To ensure that customers, as well as owners, receive the benefits of implemented recommendations, the Commission, in future rate proceedings, will require ULH&P to provide appropriate detailed information of costs, benefits, and/or costs avoided as a result of its related efforts regardless of the accounting or reporting mechanisms now in place. This information should correspond to the information periodically provided to the Commission's Management Audit Branch, or a fully detailed explanation of differences should be provided. If costs and benefits are not adequately addressed in future rate proceedings, the Commission will make appropriate adjustments.

In requiring this information, the Commission is not requesting ULH&P to develop additional reporting procedures. We are, however, requiring ULH&P to comply with the requirements of the USoA which requires utilities to keep their books of account and all supporting documentation in a manner as to be able to readily furnish full information as to any item included in any account.[125]

Individual Recommendations

ULH&P indicated that it understood that three recommendations were subject to discussion and determination by the Commission.[126] Since ULH&P further addresses these three "agree to disagree" recommendations and requests that the Commission determine how they are to be resolved,[127] the Commission will address each recommendation.

With regard to the recommendation to request additional feedback from the external auditors, the Commission does not fully agree with ULH&P's and the Board of Directors' Audit Committee's position regarding formal written communication. However, considering the decision of management and that other appropriate procedures are in place, the Commission will require no further action relative to this recommendation. Should the situation change or problems arise, however, the Commission fully expects appropriate changes to be instituted.

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125 Uniform System of Accounts, Publication Number FERC-0114, General Instructions, No. 2(A).

126 T.E., Vol. IV, March 20, 1992, page 80.

127 Brief of ULH&P, pages 33 through 36.

With regard to the recommendation to assign responsibility for salary administration, at all levels of the organization, to the Human Resource Department's Compensation and Benefits Division, the Commission finds that the decision to leave administration of management employees' compensation with the Assistant Secretary rather than transfer responsibility to the seemingly more appropriate Human Resources group to be inconsistent with the Commission's understanding of the typical duties and responsibilites of a human resource function. There is evidence regarding the reorganization of the human resource function and changing corporate culture.[128] No further action will be required at this time. However, with the changes taking place in the human resources area, the Commission would expect ULH&P to reconsider this recommendation should administration by the Human Resource function become appropriate.

With regard to the recommendation that ULH&P's Legal Department develop time sheets to record actual charges to ULH&P in enough detail to identify specific projects and services, the Commission will require that this recommendation be reconsidered and included in any determination made by ULH&P regarding the supervisory, administrative, and professional cost-allocation and time study issues addressed earlier in this Order.

To the extent that other recommendations remain ongoing or not completely implemented, the Commission fully expects ULH&P and

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128 T.E., Volume III, March 19, 1992, pages 81 through 84, 143 through 148 and Volume IV, March 20, 1992, page 69.

CG&E (to the extent that such recommendations impact ULH&P) to make a good faith effort to satisfactorily report on implementation or provide specific detailed analyses to show why implementation is not reasonable.

With respect to recommendations that are ULH&P specific or are indirectly related to ULH&P, that are being studied as part of ULH&P's integrated operations, the Commission strongly believes that specific consideration should be given to the needs of the ULH&P service area and to its customers. As the management auditors stated, ULH&P, as an integral part of CG&E, should be in a position to benefit from a level of sophistication of management and technology that it would not otherwise be able to justify.[129] However, the evidence presented in this proceeding relative to recent increases in staffing levels, the failure of ULH&P to perform the referenced analysis of staffing levels, the inability or unwillingness to adequately address cost allocation issues, and the inability to address the specific costs and benefits of the management audit, raises significant questions as to whether Kentucky customers are indeed benefiting from this relationship.

SUMMARY

After consideration of all matters of record, the evidence, and being otherwise sufficiently advised, the Commission finds that:

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129 Management And Operations Review of The Union Light, Heat And Power Company, August 1989, page 29.

1. The rates in Appendix A, attached hereto and incorporated herein, are the fair, just, and reasonable rates to be charged subject to refund by ULH&P for service rendered on and after the date of this Order.

2. The rates proposed by ULH&P would produce revenue in excess of that found reasonable herein and should be denied.

3. The rate of return granted herein is fair, just, and reasonable, and will provide for the financial obligations of ULH&P with a reasonable amount remaining for equity growth.

4. The tariff changes proposed by ULH&P, as modified herein, are reasonable and should be approved.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix A be and they hereby are approved subject to refund for service rendered by ULH&P on and after the date of this Order.

2. ULH&P shall maintain its records in such manner as will enable ULH&P, any of its customers, or the Commission to determine the amounts to be refunded and to whom due in the event a refund is ordered.

3. ULH&P shall file a notice with the Commission, with a copy to all parties of record, within 5 days of any change in the current FERC filed rate for purchased power.

4. The rates proposed by ULH&P be and they hereby are denied.

5. The tariff changes authorized herein and the tariffs set forth in Appendix A be and they hereby are approved.

6. Within 30 days from the date of this Order, ULH&P shall file with the Commission revised tariff sheets setting out the rates and tariff provisions approved herein.

Done at Frankfort, Kentucky, this 5th day of May, 1992.

PUBLIC SERVICE COMMISSION

Chairman

Commissioner

DISSENTING OPINION OF VICE CHAIRMAN THOMAS M. DORMAN

I respectfully dissent from the decision to allow ULH&P to increase its retail rates by approximately $25 million to recover increased purchase power costs due solely to the commercialization of Zimmer. CG&E's cost to convert the substantially completed nuclear facility to a coal facility should be borne by CG&E's shareholders and not by Kentucky ratepayers. There is no valid reason to justify the cost of Zimmer being at least 50 percent greater than the current cost for comparable generation.

While the rate increase authorized by the majority is subject to refund pending a full and comprehensive review of the Zimmer cost by the FERC, I strongly believe that ratepayers should not be burdened with excessive and uncertain Zimmer costs during the interim. This Commission has intervened at the FERC and will soon be sponsoring expert testimony on the unreasonableness of Zimmer's cost. As long as the Kentucky Public Service Commission is an intervenor and until the FERC has considered all the evidence and approved a final rate for purchased power, this Commission should object to any scheme which seeks to recover unreasonable Zimmer costs from Kentucky ratepayers.

Thomas M. Dorman
Vice Chairman

ATTEST:

Executive Director, Acting

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 91-370 DATED MAY 5, 1992

The following rates and charges are prescribed for the customers in the area served by The Union Light, Heat and Power Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE RATES

RATE RS
RESIDENTIAL SERVICE

Customer Charge	$3.89 Per Month
Energy Charge	
Summer Rate	
First 1,000 Kilowatt-Hours	6.806¢ Per KWH
Additional Kilowatt-Hours	7.265¢ Per KWH
Winter Rate	
First 1,000 Kilowatt-Hours	6.806¢ Per KWH
Additional Kilowatt-Hours	5.359¢ Per KWH

RATE DS
SERVICE AT SECONDARY DISTRIBUTION VOLTAGE

NET MONTHLY BILL

Computed in accordance with the following charges provided, however, that the maximum monthly rate, excluding the customer charge and the electric fuel component charges, shall not exceed 19.851 cents per kilowatt-hour.

Customer Charge	
Single Phase Service	$5.00 Per Month
Three Phase Service	$10.00 Per Month
Demand Charge:	
First 15 Kilowatts	$0.00 Per KW
Additional Kilowatts	$6.84 Per KW

Energy Charge

First 6,000 KWH	7.192¢ Per KWH
Next 300 KWH/KW	4.386¢ Per KWH
Additional KWH	3.631¢ Per KWH

For customers receiving service under the provisions of former Rate C, Optional Rate for Churches, as of June 25, 1981, the maximum monthly rate per kilowatt-hour shall not exceed 11.775 cents per kilowatt-hour plus the applicable fuel adjustment charge.

RATE DT
TIME-OF-DAY RATE FOR SERVICE AT DISTRIBUTION VOLTAGE

Customer Charge

Single Phase Service	$5.00 Per Month
Three Phase Service	$10.00 Per Month
Primary Voltage Service	$100.00 Per Month

Demand Charge

Summer

On Peak KW	$10.20 Per KW
Off Peak KW	$1.00 Per KW

Winter

On Peak KW	$8.42 Per KW
Off Peak KW	$1.00 Per KW

Energy Charge

All KWH	3.656¢ Per KWH

RATE EH
OPTIONAL RATE FOR ELECTRIC SPACE HEATING

Winter Period

Customer Charge

Single Phase Service	$5.00 Per Month
Three Phase Service	$10.00 Per Month
Primary Voltage Service	$100.00 Per Month

Demand Charge

All KW	$0.00 Per KW

Energy Charge

All KWH	5.371¢ Per KWH

RATE SP
SEASONAL SPORTS SERVICE

Customer Charge	\$5.00 Per Month
Energy Charge	8.993¢ Per KWH

RATE GS-FL
OPTIONAL UNMETERED GENERAL SERVICE RATE FOR SMALL FIXED LOADS

For Loads Based on a Range of 540 to 720 Hours Use Per Month of the Rated Capacity of the Connected Equipment	7.079¢ Per KWH
For Loads of Less Than 540 Hours Use Per Month of the Rated Capacity of the Connected Equipment	8.160¢ Per KWH

RATE DP
SERVICE AT PRIMARY DISTRIBUTION VOLTAGE

Customer Charge	
Primary Voltage Service (12.5 or 34.5 KV)	\$100.00 Per Month
Demand Charge:	
All Kilowatts	\$6.35 Per KW
Energy Charge	
First 300 KWH/KW	4.434¢ Per KWH
Additional KWH	3.650¢ Per KWH

RATE TT
TIME-OF-DAY RATE FOR SERVICE AT TRANSMISSION VOLTAGE

Customer Charge	\$500.00 Per Month
Demand Charge	
Summer	
On Peak KW	\$6.92 Per KW
Off Peak KW	\$1.00 Per KW
Winter	
On Peak KW	\$5.65 Per KW
Off Peak KW	\$1.00 Per KW
Energy Charge	
All KWH	3.606¢ Per KWH

RATE SL
STREET LIGHTING SERVICE

OVERHEAD DISTRIBUTION AREA

	Rate/Unit
Standard Fixtures	
Mercury Vapor	
7,000 Lumen	$4.99
7,000 Lumen (Open Refractor)	$3.86
10,000 Lumen	$5.38
21,000 Lumen	$6.76
Sodium Vapor	
9,500 Lumen	$6.23
9,500 Lumen (Open Refractor)	$4.46
16,000 Lumen	$6.46
22,000 Lumen	$8.35
50,000 Lumen	$10.02
Decorative Fixtures	
Sodium Vapor	
9,500 Lumen (Rectilinear)	$7.95
22,000 Lumen (Rectilinear)	$9.08
50,000 Lumen (Rectilinear)	$10.97
50,000 Lumen (Setback)	$18.00

Spans of Secondary Wiring

For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.47.

UNDERGROUND DISTRIBUTION AREA

	Rate/Unit
Standard Fixtures	
Mercury Vapor	
7,000 Lumen	$4.99
7,000 Lumen (Open Refractor)	$3.86
10,000 Lumen	$5.38
21,000 Lumen	$6.76
Sodium Vapor	
9,500 Lumen	$6.23
9,500 Lumen (Open Refractor)	$4.46
16,000 Lumen	$6.46
22,000 Lumen	$8.35
50,000 Lumen	$10.02
Decorative Fixtures	
Mercury Vapor	
7,000 Lumen (Town & Country)	$5.23
7,000 Lumen (Holophane)	$6.93
7,000 Lumen (Gas Replica)	$17.81
7,000 Lumen (Aspen)	$10.73

Sodium Vapor	
9,500 Lumen (Town & Country)	$8.98
9,500 Lumen (Holophane)	$9.53
9,500 Lumen (Rectilinear)	$7.95
9,500 Lumen (Gas Replica)	$19.10
9,500 Lumen (Aspen)	$11.40
22,000 Lumen (Rectilinear)	$9.08
50,000 Lumen (Rectilinear)	$10.97
50,000 Lumen (Set Back)	$18.00

POLE CHARGES

Pole Description	Rate/Pole
Wood	
17 Foot (Laminated)	$3.96
30 Foot	$3.90
35 Foot	$3.96
40 Foot	$4.74
Aluminum	
12 Foot (Decorative)	$10.41
28 Foot	$6.25
28 Foot (Heavy Duty)	$6.30
30 Foot (Anchor Base)	$12.49
Fiberglass	
17 Foot	$3.96
12 Foot (Decorative)	$11.66
30 Foot (Bronze)	$7.60
35 Foot (Bronze)	$7.81
Steel	
27 Foot (11 Gauge)	$10.25
27 Foot (3 Gauge)	$15.46

Spans of Secondary Wiring

For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.67.

RATE TL
TRAFFIC LIGHTING SERVICE

NET MONTHLY BILL

Where the Company supplies energy only, all kilowatt-hours shall be billed at 3.22 cents per kilowatt-hour.

Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all Kilowatt-Hours shall be billed at 1.88 cents per Kilowatt-Hour.

Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 5.10 cents per kilowatt-hour.

RATE OL
OUTDOOR LIGHTING SERVICE

Private Outdoor Lighting Units

	Rate/Unit
Standard Fixtures	
Mercury Vapor	
7,000 Lumen (Open Refractor)	$6.27
7,000 Lumen	$8.43
10,000 Lumen	$9.49
21,000 Lumen	$11.56
Sodium Vapor	
9,500 Lumen (Open Refractor)	$5.97
9,500 Lumen	$8.05
16,000 Lumen	$8.40
22,000 Lumen	$9.45
50,000 Lumen	$9.51
Decorative Fixtures	
Mercury Vapor	
7,000 Lumen (Town & Country)	$10.42
7,000 Lumen (Holophane)	$13.86
7,000 Lumen (Gas Replica)	$35.63
7,000 Lumen (Aspen)	$21.47
Sodium Vapor	
9,500 Lumen (Town & Country)	$17.92
9,500 Lumen (Holophane)	$19.07
9,500 Lumen (Rectilinear)	$15.89
9,500 Lumen (Gas Replica)	$38.24
9,500 Lumen (Aspen)	$22.82
22,000 Lumen (Rectilinear)	$18.13
50,000 Lumen (Rectilinear)	$21.93
50,000 Lumen (Setback)	$35.90

Flood Lighting Units Served in Overhead Distribution Areas

	Rate/Unit
Mercury Vapor	
21,000 Lumen	$11.56
Sodium Vapor	
22,000 Lumen	$9.24
50,000 Lumen	$10.16

RATE NSU
STREET LIGHTING SERVICE
FOR NON-STANDARD UNITS

Company Owned

	Rate/Unit
Boulevard Units Served Underground	
2,500 Lumen Incandescent - Series	$7.14
2,500 Lumen Incandescent - Multiple	$4.99
Holophane Decorative Fixture on 17 foot fiberglass pole served underground with direct buried cable	
10,000 Lumen Mercury Vapor	$12.81

The cable span charge of $.67 per each increment of 25 feet of secondary wiring shall be added to the Rate/Unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

Street Light Units Served Overhead Distribution	
2,500 Lumen Incandescent	$4.94
2,500 Lumen Mercury Vapor	$5.18
21,000 Lumen Mercury Vapor	$6.13

Customer Owned

	Rate/Unit
Steel Boulevard Units Served Underground with Limited Maintenance by Company	
2,500 Lumen Incandescent - Series	$3.76
2,500 Lumen Incandescent - Multiple	$4.78

RATE NSP
PRIVATE OUTDOOR LIGHTING FOR NON-STANDARD UNITS

	Rate/Unit
Private Outdoor Lighting Units:	
2,500 Lumen Mercury, Open Refractor	$6.12
2,500 Lumen Mercury, Enclosed Refractor	$8.66

Outdoor Lighting Units Served in Underground Residential Distribution Areas:	
7,000 Lumen Mercury, Mounted on a 17-foot Plastic Pole	$11.46
7,000 Lumen Mercury, Mounted on a 17-foot Wood Laminated Pole	$11.46
7,000 Lumen Mercury, Mounted on a 30-foot Wood Pole	$10.47
9,500 Lumen Sodium Vapor, TC 100 R	$9.13

Flood Lighting Units Served in Overhead Distribution Areas

52,000 Lumen Mercury (35-Foot Wood Pole)	$17.38
52,000 Lumen Mercury (50-Foot Wood Pole)	$20.60
50,000 Lumen Sodium Vapor	$14.20

RATE SC
STREET LIGHTING SERVICE - CUSTOMER OWNED

	Rate/Unit
Standard Fixtures	
Mercury Vapor	
7,000 Lumen	$2.38
10,000 Lumen	$2.82
21,000 Lumen	$3.58
Sodium Vapor	
9,500 Lumen	$3.62
16,000 Lumen	$3.86
22,000 Lumen	$3.92
50,000 Lumen	$4.14

	Rate/Unit
Decorative Fixtures	
Mercury Vapor	
7,000 Lumen (Holophane)	$3.29
7,000 Lumen (Town & Country)	$3.29
7,000 Lumen (Gas Light Replica)	$3.29
7,000 Lumen (Aspen)	$3.29
Sodium Vapor	
9,500 Lumen (Town & Country)	$3.64
9,500 Lumen (Rectilinear)	$3.64
9,500 Lumen (Aspen)	$3.75
9,500 Lumen (Holophane)	$3.75
9,500 Lumen (Gas Light Replica)	$3.75
22,000 Lumen (Rectilinear)	$3.92
50,000 Lumen (Rectilinear)	$4.14

	Rate/Pole
Pole Description	
Wood	
30 Foot	$3.90
35 Foot	$3.95
40 Foot	$4.73

The rate for energy used for this type of street lighting will be 3.169 cents per kilowatt-hour.

RATE SE
STREET LIGHTING SERVICE-OVERHEAD EQUIVALENT

	Rate/Unit
Decorative Fixtures	
Mercury Vapor	
7,000 Lumen (Town & Country)	$5.01
7,000 Lumen (Holophane)	$5.01
7,000 Lumen (Gas Replica)	$5.01
7,000 Lumen (Aspen)	$5.01
Sodium Vapor	
9,500 Lumen (Town & Country)	$6.25
9,500 Lumen (Holophane)	$6.25
9,500 Lumen (Rectilinear)	$6.25
9,500 Lumen (Gas Replica)	$6.25
9,500 Lumen (Aspen)	$6.25
22,000 Lumen (Rectilinear)	$8.35
50,000 Lumen (Rectilinear)	$10.02
50,000 Lumen (Setback)	$10.02

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 91-370 DATED MAY 5, 1992

The jurisdictional net original cost rate base of ULH&P's combined and electric operations at July 31, 1991 is as follows:

	Company	Electric
Total Utility Plant in Service	$269,104,101	$151,975,821
Add:		
Materials and Supplies -		
Distribution	70,214	70,214
Gas Enricher Liquids	2,331,564	0
Other	21,369	10,933
Total Materials and Supplies	2,423,147	81,147
Gas Stored Underground	793,152	0
Prepayments	609,058	144,418
Cash Working Capital Allowance	4,635,506	2,573,472
Subtotal	8,460,863	2,799,037
Deduct:		
Reserve for Accumulated Depreciation	80,606,579	49,078,228
Accumulated Deferred Income Taxes	20,619,989	13,726,430
Investment Tax Credits	239,091	96,010
Customer Advances for Construction	1,998,600	0
Subtotal	103,464,259	62,900,668
Jurisdictional Net Original Cost Rate Base	$174,100,705	$ 91,874,190

Ratio of Kentucky jurisdictional electric operations to total operations: 52.771 percent.

Notes:

1. Balances for Materials and Supplies and Prepayments were determined using 13-month average balances.

2. Prepayments do not include amounts for the PSC Assessment or auto license taxes.

3. Cash working capital allowance was determined by taking 1/8 of actual operation and maintenance expenses less energy charges for the test period.

4. Company amounts are on a jurisdictional basis.

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 91-370 DATED MAY 5, 1992

Commission's Adjustment To ULH&P's Overtime Labor Expense

Mathematic Average of Overtime Hours (Schedule C-11.1):

Year	Hours
1986	24,732
1987	50,244
1988	56,742
1989	85,863
1990	60,478
TY 7/91	62,535
Total	340,594
Average	56,766

Calculated Average Overtime Hourly Wage Rate, TY Actual:
(Schedule C-11.1)

Total Labor Overtime Dollars	$1,556,588
Total Overtime Hours	62,535
Average Overtime Rate per Hour	$24.8915

Calculation of Adjustment:

Computed Average Overtime Hours	56,766
Actual TY Overtime Hours	62,535
Proposed Reduction in Hours	(5,769)
Allocation to Electric	71.45%
Reduction Allocated to Electric	(4,122)
Average Overtime Rate per Hour	$24.8915
Electric Overtime Reduction	$(102,606)
O & M Labor Ratio (Sch. C-11.1)	72.43%
Electric O & M Overtime Reduction	$(74,318)
Jurisdictional Factor (Sch. C-11.1)	99.96%
Total Overtime Labor Reduction	$(74,287)

Note: The allocation to electric operations reflects the percentage of electric operating revenues to total operating revenues, as shown on Schedule A-3.9 of ULH&P's application.

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 91-370 DATED MAY 5, 1992

Commission's Adjustments For Employee-Related and Miscellaneous Expenses.

Account	Description	Amount
Employee-Related Expenses:		
5926-50	Americana Amusement Park - Company Picnic	$ 2,119
5926-50	Walk America / March of Dimes	228
5926-50	Children's Christmas Party	225
	Total Adjustments to Employee-Related Expenses	$ 2,572
Miscellaneous - Inappropriate for Rate-Making:		
Various	Burson-Marsteller - Commun. Act. Involvement	$ 3,142
5930-25	Color Brite Fabrics & Displays	401
5930-25	Frontier Restaurant - Dinner after Zimmer Tour	1,004
5930-50	Greater Cincinnati Convention - Bureau Dues	156
Various	Home Builders Association - Membership Dues	233
5930-30	King's Island - Employee Appreciation Day	18,111
5930-25	Martiny & Company - Speaker's Bureau Booklet	1,190
Various	Municipal Government League - Mtg. attend.	104
Various	Terrace Garden Inn - Lodging/Homebuilders Conv.	122
Various	General Physics Corp. - Review Prepared. Plan	3,938
Miscellaneous - Reclassified to Account No. 426.1:		
Various	Christmas Train Display	$ 12,258
5930-50	Cincinnati Historical Society - Dues	188
5930-30	Cincinnati Theatrical Assoc. - Sponsorship	3,968
Various	Commonwealth Hilton - Govt. Mtg./Banquet Chrg.	3,119
5930-50	Covington Business - Membership Dues	326
5930-24	Covington Business - Sponsor City Center Dinner	167
5930-24	Dan Beard Council - Leadership Luncheon	140
5930-25	Diorama Presentations - Sponsor Wilderness Adv.	4,960
5930-25	Downtown Council of Cincinnati - Walking Guide	1,190
5930-25	Greater Cincinnati Convention - Decorating	1,488
5930-24	Kenton Co. Boys/Girls Club - Outing	291
5930-24	Kincaid Regional Theatre - Sponsorship	620
5930-24	Leadership Kentucky - Share of Reception	310
5930-25	Mrs. Allison's Cookie Company - Train Display	501
5930-30	Museum Center Foundation - Theater Sponsorship	4,960
5930-24	N. Kentucky Chamber of Commerce - Dinner Mtg.	434
5930-24	N. Kentucky Chamber of Commerce - Golf Outing	279
5930-24	N. Kentucky Chamber of Commerce - Sponsorship	310
Various	N. Kentucky Chamber of Commerce - Annual Outing	339
5909-25	N. Kentucky Reading Co. - Sponsorship	744
5930-24	N. Kentucky University - Sponsorship	372
5930-30	Riverfront Coliseum - Sponsorship NBA Exhib.	496
5921-61	The University of Dayton - Scholarships	242
5921-61	Thomas More College - Scholarship	504
5930-25	Three & Associates, Inc. - Wilderness Brochure	2,425
	Total Adjustments to Miscellaneous Expenses	$ 69,032

EXHIBIT__(LK-PSC-13-4)

COMMONWEALTH OF KENTUCKY

BEFORE THE 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

I N D E X

COMMONWEALTH OF KENTUCKY

BEFORE THE 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

O R D E R

Louisville Gas and Electric Company ("LG&E"), a wholly owned subsidiary of LG&E Energy LLC ("LG&E Energy"),[1] is an electric and gas utility that generates, transmits, distributes, and sells electricity to approximately 385,000 consumers in Jefferson County and in portions of 8 counties.[2] LG&E purchases, stores, transports, distributes, and sells natural gas to approximately 312,000 consumers in Jefferson County and in portions of 15 counties.[3]

BACKGROUND

On November 24, 2003, LG&E filed a letter giving notice of its intent to file an application for approval of an increase in its electric rates to produce additional annual revenues of $63,764,203, an increase of 11.34 percent, and an increase in its gas rates to produce additional annual revenues of $19,106,269, an increase of 5.43 percent. On

[1] LG&E Energy is a Kentucky limited liability company and is an indirect subsidiary of E.ON AG ("E.ON"), a German multi-national energy corporation.

[2] The 8 counties are Bullitt, Hardin, Henry, Meade, Oldham, Shelby, Spencer, and Trimble.

[3] The 15 counties are Barren, Bullitt, Green, Hardin, Hart, Henry, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Trimble, and Washington.

December 29, 2003, LG&E filed its application, which included new rates to be effective January 31, 2004 and proposals to revise, add, and delete several tariffs applicable to its electric and gas services. To determine the reasonableness of the request, the Commission suspended the proposed rates for 5 months from their effective date, pursuant to KRS 278.190(2), up to and including June 30, 2004.

LG&E's last increase in electric rates was authorized in December 1990 in Case No. 1990-00158.[4] LG&E's last increase in gas rates was authorized in September 2000 in Case No. 2000-00080.[5] LG&E was required to reduce its electric rates as part of a rate complaint, Case No. 1998-00426,[6] in January 2000.

The following parties requested and were granted full intervention: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); the United States Department of Defense and Other Federal Executive Agencies ("DOD"); the Division of Energy ("KDOE") of the Environmental and Public Protection Cabinet; the Kentucky Industrial Utility Customers, Inc. ("KIUC"); The Kroger Company ("Kroger"); the Kentucky Association for Community Action, Inc. ("KACA"); the Metro Human Needs Alliance ("MHNA"); and People Organized and Working for Energy Reform ("POWER").

[4] Case No. 1990-00158, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company.

[5] Case No. 2000-00080, The Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks.

[6] Case No. 1998-00426, Application of Louisville Gas and Electric Company for Approval of an Alternative Method of Regulation of Its Rates and Service.

On January 14, 2004, the Commission issued a procedural schedule to investigate LG&E's rate application. The schedule provided for discovery, intervenor testimony, rebuttal testimony by LG&E, a public hearing, and an opportunity for the parties to file post-hearing briefs. On March 23, 2004, the AG, DOD, KDOE, KIUC, Kroger, KACA, MHNA, and POWER filed their testimony. Also on March 23, 2004, the Commission granted LG&E's motion to consolidate into this case that portion of Case No. 2003-00396 relating to a new LG&E tariff for Non-Conforming Load ("NCL") customers.[7] On March 31, 2004, the Commission granted a joint motion by LG&E, the AG, and KIUC to consolidate Case No. 2003-00335, an investigation of the Earnings Sharing Mechanism ("ESM") for LG&E, into this proceeding.[8] LG&E filed its rebuttal testimony on April 26, 2004.

On April 28, 2004, an informal conference was held to discuss procedural matters and the possible resolution of pending issues. Additional conferences were held on April 29, 2004 and May 3, 2004. The public hearing was convened on May 4,

[7] Case No. 2003-00396, Tariff Filing of Kentucky Utilities Company and Louisville Gas and Electric Company for Non-Conforming Load Customers. On February 13, 2004, LG&E filed its motion to consolidate Case No. 2003-00396 with its rate case. On March 19, 2004, LG&E filed an amendment to its motion to clarify that it was seeking to have Case No. 2003-00396 bifurcated and the respective portion consolidated with the LG&E rate case.

[8] Case No. 2003-00335, An Investigation Pursuant to KRS 278.260 of the Earnings Sharing Mechanism Tariff of Louisville Gas and Electric Company. LG&E, the AG, and KIUC filed their joint motion on December 18, 2003. On January 16, 2004, LG&E, the AG, and KIUC filed a letter requesting that their motion to consolidate be held in abeyance. They filed another letter on March 12, 2004, requesting the Commission to rule on their motion to consolidate.

2004,[9] at which time the parties indicated that significant progress had been made toward resolving many of the issues, and they requested the hearing be delayed to allow additional discussions.[10] This request was granted, and on May 5, 2004, the parties announced a tentative agreement on two documents that resolved many of the issues. One document, titled "Settlement Agreement" ("ESM Settlement"), provided for the orderly discontinuance of the ESM. The other document, titled "Partial Settlement Agreement, Stipulation and Recommendation" ("Partial Settlement and Stipulation"), addressed all the remaining issues, including the NCL tariff, and resolved many but not all of the issues raised in LG&E's rate case.

Because the Partial Settlement and Stipulation did not resolve appropriate revenue increase and depreciation rates for LG&E's electric operations,[11] the hearing proceeded in the afternoon of May 5, 2004 with testimony being presented by LG&E and the AG. The hearing on those issues concluded on May 6, 2004. The parties subsequently finalized the ESM Settlement and the Partial Settlement and Stipulation

[9] For administrative efficiency, the public hearing for this case and the general rate case for the Kentucky Utilities Company ("KU") were held simultaneously. See Case No. 2003-00434, An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company.

[10] Transcript of Evidence ("T.E."), Volume I, May 4, 2004, at 36-39 and 57-60.

[11] At the beginning of the hearing on May 5, 2004, the AG had not agreed with the other parties on the revenue increases and depreciation rates for both LG&E's electric and gas operations. During the hearing on May 5, 2004, the AG reached agreement on the revenue increase for LG&E's gas operations. See T.E., Volume II, May 5, 2004, at 40-41.

and, on May 12, 2004, they filed the final versions of both documents.[12] During the hearing, or by subsequent written request, the DOD, KDOE, KIUC, Kroger, KACA, MHNA, and POWER withdrew their respective prefiled testimonies and responses to data requests on those testimonies. The AG also withdrew his prefiled testimony on all issues except LG&E's electric revenue requirement and depreciation rates.[13] A hearing was then held on that date to receive testimony on the reasonableness of both documents.

On June 4, 2004, LG&E and the AG timely filed briefs in accordance with the procedural schedule. All information requested at the public hearing has been filed and the case now stands submitted for a decision.

ESM SETTLEMENT

LG&E previously submitted its calendar year 2003 ESM filing pursuant to its ESM tariff, and it was docketed as Case No. 2004-00069.[14] In that filing, LG&E calculated its 2003 ESM billing factor to be 2.282 percent for April 1, 2004 through April 30, 2004, and 2.360 percent for May 1, 2004 through March 31, 2005.[15]

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[12] The ESM Settlement is attached hereto as Appendix A, and the Partial Settlement and Stipulation is attached hereto as Appendix B. Both documents are incorporated into this Order as if fully set forth herein.

[13] T.E., Volume IV, May 12, 2004, at 8-9 and 12-15.

[14] Case No. 2004-00069, Louisville Gas and Electric Company's Annual Earnings Sharing Mechanism Filing for Calendar Year 2003.

[15] Under the provisions of its ESM tariff, LG&E is required to file a determination of a balancing adjustment to the current ESM billing factor, reflecting a true-up for any over- or under-collections experienced with the previous ESM billing factor. The revision in the 2003 ESM billing factor reflects the balancing adjustment for the 2002 ESM billing factor.

Under the terms of the ESM Settlement, the parties recommend that an Order be issued in Case No. 2004-00069 approving LG&E's 2003 ESM billing factor as filed and authorize LG&E to bill them through March 31, 2005. LG&E would then collect and retain all this revenue. No later than May 2005, LG&E is to perform a final balancing adjustment to reconcile any over- or under-collection of the 2003 ESM revenues as billed from April 2004 through March 2005. Effective July 1, 2004, the ESM will be discontinued and LG&E will waive its rights to make any billings or seek any collections under its ESM tariff for its operations during the first 6 months of 2004.

The Commission has reviewed the ESM Settlement and finds that it constitutes a reasonable resolution of the issues related to the continuation of LG&E's ESM. When the Commission offered the ESM to LG&E in 2000, the intent was that this alternative form of regulation would provide sufficient incentives to LG&E to improve its performance while reducing the business risks inherent in over- and under-earnings. The management audit performed for the Commission concluded,[16] and LG&E confirmed in its own testimony, that the ESM has not incented LG&E to operate any differently than it would have without an ESM. In light of these results, the termination of the ESM as currently configured is reasonable. Therefore, the Commission will

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[16] The Barrington-Wellesley Group, Inc. ("BWG") performed the ESM management audit and issued its final report on August 31, 2003. BWG determined that the ESM was an effective alternative to traditional cost of service regulation, although it did recommend some modifications to the current structure. The BWG report stated "However, it is the LG&E/KU management's position that the ESM program did not change management behavior. Management contends that LG&E and KU already had a strong continuous improvement program and that the ESM reinforced this behavior and added a regulatory mechanism for dealing with the ebb and flow of earnings over time." BWG Report at IV-1.

approve the ESM Settlement in its entirety. An Order confirming this will be issued in Case No. 2004-00069 in the near future.

The Commission notes that the ESM Settlement provides that nothing therein will bar a party from seeking, or the Commission from reinstating, an ESM which is designed to accomplish reasonable and valid regulatory objectives. While the Commission is now approving the termination of the current ESM because it did not achieve its intended purpose, we will take this opportunity to reaffirm our support for alternative rate-making mechanisms. LG&E is encouraged to continue considering alternative regulation, and, if it decides to propose one in the future, it should do so after seeking input from its customer representatives.

PARTIAL SETTLEMENT AND STIPULATION

Unanimous Provisions

Gas Operations

The Partial Settlement and Stipulation reflects a unanimous resolution of all issues raised in LG&E's gas rate case, except its depreciation rates. The gas issues thus resolved include the amount of the revenue increase, the revenue allocations and rate design, and the proposed changes in the terms and conditions of gas service. The major provisions of the Partial Settlement and Stipulation as they relate to LG&E's gas operations are as follows:

- Effective July 1, 2004, LG&E's gas operation revenues should be increased by $11,900,000.

- The gas rates as set forth in Exhibit 1 to the Partial Settlement and Stipulation are the fair, just, and reasonable rates for LG&E's gas operations and those rates should be approved by the Commission.

- LG&E's gas purification and gas storage loss expenses should be recovered as part of its Gas Supply Clause mechanism.

- The notice period for an Operational Flow Order pursuant to LG&E's Rate FT should be 24 hours.

- All miscellaneous charges applicable to gas operations should be approved as proposed by LG&E, except that the Disconnect-Reconnect Charge should be $20.00.

- The monthly residential gas customer charge should be $8.50 per month and all other customer charges applicable to gas operations should be implemented as proposed by LG&E.

- LG&E will withdraw its Standard Riders for Summer Air Conditioning Service for its gas operations and customers served under those riders will take service under otherwise applicable rate schedules.

Electric Operations

The Partial Settlement and Stipulation reflects a unanimous resolution of a substantial number of the issues raised, including the revenue allocations, rate design issues, and LG&E's proposed changes in its electric operations terms and conditions of service. The major provisions of the Partial Settlement and Stipulation for LG&E's electric operations that have been unanimously agreed to are as follows:

- LG&E will establish a pilot time-of-day program for commercial customers with a monthly demand between 250 kW and 2,000 kW.[17]

- Future Commission Orders approving cost recovery of LG&E's environmental projects pursuant to KRS 278.183 are to be based upon an 11.00 percent return on common equity until directed by Order of the Commission that a different rate of return shall be utilized.

- All costs associated with LG&E's 1995 environmental compliance plan will be removed from LG&E's monthly environmental surcharge filings and will be recovered in LG&E's base rates.

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[17] Reflects a stipulation agreement between LG&E and Kroger dated May 4, 2004 and attached to the Partial Settlement and Stipulation as Exhibit 2.

- LG&E will establish a real time pricing pilot program for a 3-year term and participation will be limited to up to 50 customers under Rate R and up to 50 customers under Rate GS; customers under Rate LP are to be eligible for inclusion in the second year of the pilot program.

- All miscellaneous charges applicable to electric operations should be approved as proposed by LG&E except that the Disconnect-Reconnect Charge should be $20.00.

- The monthly residential electric customer charge should be $5.00 per month; Rate GS electric single phase should be $10.00 per month; Rate GS electric three phase should be $15.00 per month; and all other customer charges applicable to electric operations should be implemented as proposed by LG&E.

- LG&E Rate GS should be available to electric customers with connected loads up to 500 kW.

- LG&E will not bill an additional customer charge to Rate GS customers formerly taking service under the Rider for Electric Space Heating Service under Rate GS.

- LG&E will eliminate the seasonal rate structure for Rate RS and will implement a non-seasonally differentiated rate structure for Rate RS.

- LG&E will offer a Curtailable Service Rider ("CSR1") to current customers who meet the eligibility requirements set forth in LG&E's proposed CSR1, subject to specific terms and conditions.

- New customers not currently served by an existing CSR will be eligible to take curtailable service under a new CSR tariff ("CSR2") as proposed by LG&E, except such customers will be able to buy through a request for curtailment only after having been on the CSR2 service for 3 years with no failure to curtail when requested.

- The NCL service should be renamed the "large industrial-time of day" ("LI-TOD"), and the LI-TOD should be the same as the NCL tariff proposed in Case No. 2003-00396, subject to changes outlined in the Partial Settlement and Stipulation.

<u>Gas and Electric Operations</u>

The Partial Settlement and Stipulation also contains the following provisions relating to both the gas and electric operations that were unanimously agreed to:

- Unless the Commission has already modified or terminated the Value Delivery Team ("VDT") surcredit in a subsequent rate case, 6 months prior to the expiration of the 60-month period in which the VDT surcredits are in operation, LG&E will file with the Commission a plan for the future rate-making treatment of the VDT surcredits, shareholder savings, amortization of VDT costs, and all other VDT-related issues. The VDT surcredit tariff will remain in effect following the 60th month until the Commission enters an Order on the future rate-making treatment.

- In conjunction with the AG, KACA, MHNA, and POWER, LG&E will file plans for program administration with the Commission for a year-round Home Energy Assistance ("HEA") program based solely upon a 10-cent per residential meter per month charge for a period of 3 years. The HEA programs will be operated by existing social service providers with experience in operating low-income energy assistance programs, and the providers will be entitled to recover actual operating expenses not to exceed 10 percent of total HEA funds collected. The HEA programs to be filed will commence on October 1, 2004. The Commission's approval of the Partial Settlement and Stipulation will constitute approval of the HEA parameters as proposed, subject to further review by the Commission of additional programmatic details.

- Those parties that are also parties to the Franklin Circuit Court actions agree that upon Commission approval of the Partial Settlement and Stipulation, they will jointly move the Franklin Circuit Court for the entry of an order dismissing the pending HEA and Pay As You Go appeals, Civil Action Nos. 02-CI-00991 and 03-CI-00634, respectively.

- LG&E will phase out its Pay As You Go program by limiting the program to existing customers and by removing those meters from existing customers as requested, as meters fail, or as customers move off the system. LG&E reserves the right to completely terminate the program upon 60 days advance notice to the Commission. LG&E will not seek approval of a new prepaid metering program for a period of 5 years and any such program proposed thereafter will be subject to prior Commission approval.

Non-unanimous Provisions

The partial Settlement and Stipulation contains additional provisions that relate to issues in the rate case that were agreed to by all parties except the AG. Consequently, the Commission cannot accept these non-unanimous provisions as resolutions of the issues covered. The non-unanimous provisions which were agreed to by LG&E and all intervenors except the AG are as follows:

- Effective July 1, 2004, LG&E's electric operation revenues should be increased by $43,400,000.

- The electric rates as set forth in Exhibit 1 to the Partial Settlement and Stipulation are the fair, just, and reasonable rates for LG&E's electric operations and those rates should be approved by the Commission.

- LG&E's depreciation rates should remain the same as approved in the Order of December 3, 2001 in Case No. 2001-00141,[18] until the approval by the Commission of new depreciation rates for LG&E. LG&E must seek approval by filings made in its next general rate case or June 30, 2007, whichever occurs earlier. The new depreciation filings are to be based on plant in service as of a date no earlier than 1 year prior to such filing. From and after the effective date hereof, LG&E will maintain its books and records so that net salvage amounts may be identified.

Gas Operations

LG&E and all the intervenors unanimously agree that the provisions in the Partial Settlement and Stipulation, which relate to LG&E's gas operations, are reasonable and should be accepted by the Commission as a complete resolution of those issues.

The Partial Settlement and Stipulation sets forth only the amount of revenue increase agreed to, not the underlying calculations and adjustments. In determining the overall reasonableness of the proposed $11,900,000 increase in LG&E's gas operations annual revenues, the Commission has evaluated LG&E's proposed adjustments to capital, rate base, operating revenues, and operating expenses in light of our normal rate-making treatment. In addition, consideration has been given to the rates of return on common equity authorized by the Commission in recent rate cases. Based on a

[18] Case No. 2001-00141, Application of Louisville Gas and Electric Company for an Order Approving Revised Depreciation Rates.

review of all these factors and the evidence of record, the Commission finds that the level of revenue provided for in the Partial Settlement and Stipulation for LG&E’s gas operations should produce earnings that fall within in a range reasonable for both LG&E and its gas ratepayers. The $11,900,000 gas revenue increase provided for in the Partial Settlement and Stipulation will result in fair, just, and reasonable gas rates for LG&E.

Electric Operations

In its application, LG&E proposed an annual increase in its electric revenues of $63,764,203. The AG proposed an annual increase in LG&E’s electric revenues of $12,141,000. In the Partial Settlement and Stipulation, LG&E and all the intervenors except the AG agree that an annual increase in electric revenues of $43,400,000 is reasonable. Since all parties have not reached a unanimous settlement on LG&E’s electric revenues, the Commission must consider all the record evidence on this issue, including the issue of depreciation rates, and render a decision. This decision will be based on a determination, for LG&E’s electric operations, of its capital, rate base, operating revenues, and operating expenses as would normally be done in a rate case.

TEST PERIOD

LG&E proposes the 12-month period ending September 30, 2003 as the test period for determining the reasonableness of its proposed electric rates. The AG also utilized this 12-month period. The Commission finds it is reasonable to utilize the 12-month period ending September 30, 2003 as the test period in this proceeding. In utilizing a historic test period, the Commission has given full consideration to appropriate known and measurable changes.

RATE BASE

Rate Base Allocation Ratio

LG&E's application proposed a test-year-end electric rate base of $1,675,374,829,[19] and this amount was accepted by the AG.[20] The test-year-end electric rate base is divided by LG&E's test-year-end total company rate base to derive a rate base allocation ratio ("allocation ratio"). This allocation ratio is then applied to LG&E's total company capitalization to determine LG&E's electric capitalization. The allocation ratio uses the test-year-end rate base before recognizing rate-making adjustments applicable to either the electric or gas operations. LG&E and the AG used an allocation ratio of 84.13 percent.[21]

The Commission has reviewed the calculation of the test-year-end electric rate base and agrees with the calculation, except for the treatment of accumulated deferred income taxes ("ADIT") associated with Statement of Financial Accounting Standards ("SFAS 109") No. 109. The balance for ADIT used in the determination of rate base reflects the account balances for four accounts in the Uniform System of Accounts ("USoA"): Account Nos. 190, 281, 282, and 283.[22] Account No. 190 normally has a debit balance, while the remaining three accounts normally have credit balances. The

[19] Rives Direct Testimony, Rives Exhibit 3, page 1 of 2.

[20] Henkes Electric Direct Testimony, Schedule RJH-3.

[21] Rives Direct Testimony, Rives Exhibit 3, page 1 of 2.

[22] Account No. 190, Accumulated Deferred Income Taxes; Account No. 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account No. 282, Accumulated Deferred Income Taxes – Other Property; and Account No. 283, Accumulated Deferred Income Taxes – Other. The Commission notes that LG&E's financial statements do not show a balance for Account No. 281.

balances in these accounts are netted together to determine the amount to be included in the rate base calculations. If the net ADIT amount is a net credit balance, it is shown in the rate base calculations as a positive deduction, while a net debit balance is shown as a negative deduction.

When LG&E calculated its test-year-end rate base, it reported the total net credit balance resulting from Account Nos. 190, 282, and 283 as ADIT.[23] The subaccounts making up the balances for these three accounts included SFAS 109 ADIT subaccounts.[24]

LG&E then reported the net balance of Account Nos. 182.3 and 254[25] as its SFAS 109 ADIT. The SFAS 109 ADIT amounts from Account Nos. 190, 282, and 283 have a net debit balance, while the SFAS 109 amounts from Account Nos. 182.3 and 254 have a net credit balance. The erroneous inclusion of the balances from Account Nos. 182.3 and 254 has the effect of partially offsetting the SFAS 109 ADIT recorded in Account Nos. 190, 282, and 283. This results in the deductions section of the rate base being overstated and the total rate base being understated. The correct presentation of the ADIT balances is the separation of the SFAS 109 ADIT from the regular ADIT.

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[23] Consistent with previous Commission decisions, LG&E also excluded ADIT associated with its supplemental executive retirement income plan from the ADIT balance included in the rate base calculation. See Response to the Commission Staff's Second Data Request dated February 3, 2004, Items 15(d)(1) and 15(d)(2).

[24] Response to the Commission Staff's First Data Request dated December 19, 2003, Item 13(c), pages 5, 8, and 9 of 19.

[25] Account No. 182.3, Other Regulatory Assets and Account No. 254, Other Regulatory Liabilities. The subaccount balances used in the calculation are identified as SFAS 109 taxes. For Account No. 254, LG&E used the subaccount balances for 254001 through 254004. See Response to the Commission Staff's First Data Request dated December 19, 2003, Item 13(c), pages 3 and 8 of 19.

The Commission believes the ADIT and SFAS 109 ADIT included in the rate base calculations should reflect only the balances as recorded in Account Nos. 190, 282, and 283. The calculation of LG&E's test-year-end electric operations and total company rate bases and the allocation ratio are shown in Appendix D. Therefore, the Commission has determined that LG&E's allocation ratio is 84.33 percent.

Pro Forma Electric Rate Base

LG&E calculated a pro forma electric rate base of $1,468,685,936,[26] while the AG proposed a pro forma electric rate base of $1,479,108,000.[27] Both calculations reflected the approach utilized by the Commission in previous rate cases to determine the pro forma rate base, but neither calculation recognized certain adjustments normally included therein.

While LG&E removed the utility plant, construction work in progress, and accumulated depreciation associated with its Post-1995 environmental compliance plan ("Post-1995 Plan"), it should have removed the ADIT associated with the Post-1995 Plan. Excluding the Post-1995 Plan ADIT is consistent with the Commission's treatment of this item in Case No. 1998-00426.[28] LG&E should have included in its balance for accumulated depreciation its proposed increase in electric depreciation expense, an adjustment the Commission has consistently recognized.[29] Finally, LG&E

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[26] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 39.

[27] Henkes Electric Direct Testimony, Schedule RJH-3.

[28] Case No. 1998-00426, final Order dated January 7, 2000, at 60-62 and Appendix A, and rehearing Order dated June 1, 2000, at 1-4.

[29] Case No. 2000-00080, final Order dated September 27, 2000, at 18-20.

should not have included in its materials and supplies the 13-month average balance for carbide lime inventory because that inventory has been written off.

The AG's pro forma electric rate base did include adjustments for the Post-1995 Plan ADIT, the AG's proposed reduction in depreciation expense, and the adjustment to remove the carbide lime inventory. However, the AG should have recalculated the cash working capital allowance to reflect the impact of all his proposed expense adjustments.

The Commission has determined LG&E's pro forma electric rate base for rate-making purposes by beginning with the test-year-end electric rate base utilized to determine the allocation ratio, and then incorporating the adjustments discussed previously in this Order. The adjustment to accumulated depreciation reflects the decrease in test-year depreciation expense discussed later in this Order. The cash working capital allowance has been adjusted to reflect the accepted pro forma adjustments to operation and maintenance expenses as discussed later in this Order.[30]

Based upon the previous findings, we have determined LG&E's pro forma electric rate base for rate-making purposes as of September 30, 2003 to be as follows:

[30] The adjustments made to determine the pro forma electric rate base are listed in Appendix C.

Total Utility Plant in Service	$3,020,944,877
Add:	
Materials & Supplies	55,499,409
Prepayments	2,882,693
Cash Working Capital Allowance	55,028,689
Subtotal	$ 113,410,791
Deduct:	
Accumulated Depreciation	1,336,898,715
Customer Advances	507,146
Accumulated Deferred Income Taxes	325,490,421
SFAS 109 Accumulated Deferred Income Taxes	(34,633,001)
Investment Tax Credit (prior law)	3,943
Subtotal	$1,628,267,224
Pro Forma Electric Rate Base	$1,506,088,444

Reproduction Cost Rate Base

LG&E presented a total company reproduction cost rate base of $3,691,607,919, and an electric operations reproduction cost rate base of $3,036,157,656.[31] The costs were determined principally by indexing the surviving plant and equity using the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price Index.[32] The Commission has given consideration to the proposed reproduction cost rate base, but finds that using LG&E's historic cost for rate base is appropriate and consistent with precedents for LG&E and other utilities within Kentucky.

CAPITALIZATION

LG&E proposed an adjusted electric operations capitalization of $1,485,701,357.[33] Included in its electric capitalization were adjustments for the Job

[31] Rives Direct Testimony, Rives Exhibit 4.

[32] Rives Direct Testimony at 27.

[33] Rives Direct Testimony, Rives Exhibit 2, page 1 of 2.

Development Investment Tax Credit ("JDIC"), the removal of 25 percent of inventories associated with Trimble County Unit 1,[34] LG&E's equity investment in the Ohio Valley Electric Corporation ("OVEC"), the removal of reimbursed capital invested to repair the combustion turbines at the E. W. Brown Generating Station, the removal of LG&E's Post-1995 environmental compliance plan investments, and to reverse LG&E's minimum pension liability adjustment to Other Comprehensive Income. LG&E allocated the minimum pension liability adjustment to common equity only, while it allocated all other proposed adjustments on a pro rata basis to all components of capitalization.

The AG proposed an adjusted electric operations capitalization of $1,460,257,000.[35] The AG agreed with all of LG&E's adjustments to capitalization except the adjustment for the minimum pension liability. Both LG&E and the AG determined the electric capitalization by multiplying LG&E's total company capitalization by the allocation ratio described above. This is consistent with the approach used by the Commission in previous LG&E rate cases.

Minimum Pension Liability

LG&E adopted SFAS No. 130, *Reporting Comprehensive Income*, on January 1, 1998. SFAS No. 130 requires a company to report a measure of all changes in equity, not just resulting from transactions and economic events currently reflected in the determination of net income. The changes that are not currently reflected in net income are called Other Comprehensive Income items. Other Comprehensive Income items

[34] The 25 percent adjustment for Trimble County inventories is consistent with the Commission's decision in Case No. 1990-00158. See Case No. 1990-00158, final Order dated December 21, 1990 at 14-15.

[35] Henkes Electric Direct Testimony, Schedule RJH-2.

include foreign currency translation changes, unrealized holding gains and losses on available-for-sale securities, mark-to-mark gains and losses on cash flow hedges, and minimum pension liability. For each of these items, the liability is fully recognized on the balance sheet but not yet on the income statement, because the financial impact that unrealized changes in value may eventually cause have not occurred and have not been included in the income statement under generally accepted accounting principles.[36] A minimum pension liability occurs when, as of a measurement date,[37] the discounted benefits previously earned by participants in the pension plan exceed the market value of the pension trust assets, thus representing an unfunded pension benefit earned by plan participants to date.

For calendar year 2002, due to the below-average performance of the stock market and low interest rates, LG&E determined it had a total company minimum pension liability of $30,242,903, with $25,443,354 applicable to its electric operations.[38] LG&E recorded the $25,443,354 as a component of its Other Comprehensive Income and reduced its equity accordingly. LG&E argued that it would be an unfair regulatory policy to reduce common equity today for a loss not yet recorded on the income statement, and a loss that may or may not actually be incurred.[39] In its application, LG&E requested that it be permitted to reverse the entry for the minimum pension

[36] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 15(a)(3), page 8 of 16.

[37] The measurement date is normally the last day of a calendar year.

[38] Rives Direct Testimony, Rives Exhibit 2, page 2 of 2.

[39] Rives Direct Testimony at 24.

liability and record a regulatory asset to effect the reversal. The minimum pension liability is recalculated every year and, consequently, the regulatory asset would be revised and adjusted annually. Because of this feature, LG&E contended that the regulatory asset would not have to be amortized.

The AG opposed the proposed adjustment citing three reasons. First, the AG contended that the equity adjustment had actually been made and was an actual known and measurable adjustment to capitalization. Because of this fact, the AG believed that reversing the write-down was not consistent with previous Commission decisions. Second, the AG did not believe the creation of the regulatory asset as proposed by LG&E was consistent with or allowed by SFAS No. 71. The AG believes that regulatory assets established under SFAS No. 71 are recovered through amortization of the asset to the income statement, while the proposed regulatory asset for the minimum pension liability would be extinguished through balance sheet accounting. Lastly, the AG expressed concern that the establishment of the regulatory asset for the minimum pension liability would result in a presumption that the underlying costs are recoverable from ratepayers in the future and any prudence review of those costs in the future would be precluded.[40]

LG&E disagreed with the AG's arguments, noting that the write-down is not a permanent adjustment to its equity balance since the minimum pension liability will change with each measurement date. LG&E argued that the AG's reliance on the Commission's decision in Case No. 1998-00426 had no bearing on how the reversal of the write-down for the minimum pension liability should be treated. As to establishing a

[40] Henkes Direct Testimony at 10-12.

regulatory asset under SFAS No. 71, LG&E stated that the Federal Energy Regulatory Commission ("FERC") has issued an accounting decision permitting the establishment of the minimum pension liability regulatory asset for utilities with cost-based regulated rates.[41] LG&E dismissed the AG's concern that the creation of the regulatory asset would preclude a prudence review of pension costs in the future, noting that LG&E had not asserted such a claim and that the AG's witness had agreed that the FERC decision letter had eliminated the prudence concern.[42]

The Commission has not previously addressed this issue. The accounting treatment for the minimum pension liability is in effect a means of disclosing a contingency, since there is no corresponding change in the company's current pension expense recognized in the income statement. The minimum pension liability required by SFAS No. 130 and the proposed regulatory asset are unique, in that the balance is determined periodically and the recorded liability and proposed asset are adjusted accordingly. In the event the market value of the pension trust assets exceed the discounted benefits previously earned by participants in the pension plan, there would be no minimum pension liability and no corresponding adjustment to the company's equity.

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[41] Rives Rebuttal Testimony at 8. In a request dated October 31, 2003, the Edison Electric Institute filed a request with FERC seeking an accounting ruling supporting the creation of a regulatory asset for those utilities required to recognize a minimum pension liability as part of the determination of Other Comprehensive Income. On March 29, 2004, FERC's Deputy Executive Director and Chief Accountant issued a decision in FERC Docket No. AI04-2-000 allowing for the creation of the regulatory asset for accounting purposes. See Rives Rebuttal Testimony, SBR Rebuttal Exhibit 1.

[42] Joint Post-Hearing Brief of LG&E and KU at 27.

The Commission finds LG&E's adjustment to be reasonable. The write-down of LG&E's equity due to the minimum pension liability is not a permanent event, with the adjustment recalculated at the measurement date of the pension plan. Consequently, this adjustment to equity is not the same as the adjustment cited by the AG from Case No. 1998-00426. The accounting decision issued by FERC addresses the AG's concerns regarding the legitimacy of creating the regulatory asset, and that the regulatory asset will not be amortized and recognized as a current operating expense.[43] Lastly, the Commission stresses that establishing this regulatory asset creates no presumption that the underlying pension costs are either reasonable or recoverable from ratepayers in the future.

Based upon these findings, LG&E's proposal is accepted and the equity in its electric operations capitalization is increased by $25,443,354.

SFAS No. 143 – Asset Retirement Obligation ("ARO") Adjustment

LG&E adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003. Under SFAS No. 143, if a utility determines it has a legally enforceable ARO, the utility must measure and record the liability for the ARO on its books. The liability must be recorded at fair market value in the period that the liability is incurred. A corresponding and equivalent ARO asset is also recorded on the utility's books to recognize the cost of removal as an integral part of the cost of the associated tangible asset. Utilities are also required to recognize the cumulative effect impact on their financial statements resulting from the adoption of SFAS No. 143. The cumulative

[43] The Commission notes that the FERC accounting decision was issued after the AG had filed his direct testimony in this case.

effect impact represents the ARO asset depreciation and ARO liability accretion that would have been recorded had the asset and liability been recorded when the original asset was placed into service. On April 9, 2003, FERC issued Order No. 631,[44] which generally adopted the requirements of SFAS No. 143.

In Case No. 2003-00426,[45] LG&E sought approval of an accounting adjustment to its ESM for calendar year 2003 to reflect its adoption of SFAS No. 143 in 2003. LG&E and KIUC, the only intervenor in that case, filed a stipulation that resolved all issues raised therein. Among other things, the stipulation provided that, "The ARO assets, related ARO asset accumulated depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143 will be excluded from rate base."[46]

Now, LG&E has proposed to remove the cumulative effect of the accounting change resulting from the adoption of SFAS No. 143[47] and to remove the ARO assets from the determination of its pro forma rate base.[48] However, LG&E did not propose any adjustment to its electric operations capitalization corresponding with the rate base

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[44] FERC Order No. 631 is the final rule in *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Docket No. RM02-7-000.

[45] Case No. 2003-00426, Application of Louisville Gas and Electric Company for an Order Approving an Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003.

[46] Case No. 2003-00426, final Order dated December 23, 2003 at 3.

[47] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.25.

[48] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 39, page 1 of 2, line 5. The adjustment to the pro forma electric rate base was $4,585,010.

adjustment for the ARO asset. In order to be consistent with LG&E's efforts to remove the impact of the adoption of SFAS No. 143, it is necessary to exclude the ARO assets from LG&E's electric capitalization. Such an adjustment is also consistent with previous decisions by the Commission when items are removed from the calculation of rate base. Therefore, the Commission has reduced LG&E's electric capitalization, on a pro rata basis, by $4,585,010.

Based on the findings herein, the Commission has determined that LG&E's test-year-end electric capitalization should be $1,484,965,466. The calculation of the electric capitalization is shown in Appendix E.

REVENUES AND EXPENSES

For the test year, LG&E reported actual net operating income from electric operations of $108,683,393.[49] LG&E proposed a series of adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income from electric operations of $68,010,218.[50] The AG also proposed numerous revenue and expense adjustments, resulting in adjusted net operating income from electric operations of $87,108,000.[51] The Commission finds that 20 of the adjustments, proposed in LG&E's application and accepted by the AG, are reasonable and will be accepted. During the proceeding, LG&E identified and corrected errors in several other adjustments originally proposed in its application. The Commission finds that three of these other adjustments, as corrected by LG&E and

[49] Rives Direct Testimony, Rives Exhibit 1, page 1 of 3, line 1.

[50] Id., page 3 of 3, line 44.

[51] Henkes Electric Direct Testimony, Schedule RJH-4.

accepted by the AG, are reasonable and they will also be accepted. All of these 23 adjustments are set forth in detail in Appendix F, which is attached hereto.

The Commission makes the following modifications to the remaining proposed adjustments:

Unbilled Revenues

LG&E proposed an adjustment to eliminate the effect of unbilled electric revenues for rate-making purposes. The rationale for such an adjustment is to develop a better match of test-year revenues and expenses, using as-billed revenues for rate-making purposes rather than the revenues recorded on an accrual basis for accounting purposes. LG&E made its adjustment by shifting unbilled revenues for the month immediately preceding the test year into the test year (when they were actually billed) and shifting unbilled revenues for the last month of the test year to the first month after the test year. This has the effect of netting the amount of unbilled revenues at test-year-end and at the beginning of the test year. LG&E's adjustment reduced electric revenues by $1,867,000.

The AG did not oppose LG&E's unbilled revenues adjustment, but he did propose a corresponding electric expense adjustment to reflect the expense side of an adjustment that reduces test-year sales volumes by 4,095,000 Kwh. The AG calculated an expense reduction of $1,042,000 based on the 55.79 percent operating ratio used by LG&E to calculate its customer growth adjustment.

LG&E objected to the AG's expense adjustment. Since the revenues eliminated by LG&E's adjustment included the recovery of environmental surcharge, fuel clause and demand-side management costs that are removed from test-year operating results through various other adjustments, LG&E argued that any mismatch that the AG was attempting to correct is already accounted for in adjustments made specifically to address those items of expense. LG&E also stated that, to the extent that other factors impact the calculation of unbilled revenues, such as changes in the number of customers, plant closings or customer rate switching, the pro forma adjustments it proposed for those items properly normalize for those factors. LG&E also noted that the Commission had accepted similar unbilled revenues adjustments in its last electric and its last gas rate cases.

The AG's arguments in support of its expense adjustment fail to demonstrate a link between unbilled revenues and expenses sufficient to create a mismatch of revenues and expenses absent an adjustment to reduce expenses. To the extent that such a link does exist, LG&E's arguments convince us that any resulting mismatch is adequately mitigated by the various normalization adjustments included in its rate application. Based on all of the evidence on this issue, we find the AG's expense adjustment to be unnecessary and we will accept LG&E's unbilled electric revenue adjustment as proposed.

Year-End Customer Adjustment

LG&E proposed to annualize its test-year electric revenues based on the number of customers served at test-year-end. Its adjustment was based on a comparison of the number of electric customers at year-end to the 12-month average for the test year for each customer class. It proposed a corresponding electric expense adjustment, based on an operating ratio of 55.79 percent of the revenue adjustment, to reflect the related increase in variable operating expenses. LG&E's proposed adjustment increased electric revenues by $2,614,347 and electric expenses by $1,458,544.

The AG proposed an alternative customer growth adjustment. For the residential class, he calculated an increase in revenues based on a trend of customer growth over the period 1999-2003, while for the remaining classes he proposed comparing a 13-month average to the year-end number of customers. For his expense adjustment, the AG used the same operating ratio approach used by LG&E. The AG proposed this same trend approach, which was accepted by the Commission, for Delta Natural Gas Company in Case No. 1997-00066.[52] The AG's proposed adjustment increased electric revenues by $3,247,228 and increased electric expenses by $1,811,628.

LG&E objected to the AG basing an adjustment on customer growth trends from a period largely outside the test year. LG&E stated that, in making a year-end adjustment, the only relevant factor is how year-end customers compare to test-year average customers. LG&E also noted that adjustments based on a 12-month average had been accepted by the Commission in previous LG&E rate cases.

Although the Commission strives for consistency on these issues, we recognize that we have accepted different methodologies to calculate customer growth adjustments in prior rate cases.[53] However, each case is decided on its merits, and each adjustment is based on the evidence of record. In this record, the methods

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[52] Henkes Electric Direct Testimony at 35.

[53] See Case No. 1990-00158, December 21, 1990 Order at 40; Case No. 1998-00455, Application of Grayson Rural Electric Cooperative Corporation for an Adjustment of Rates, final Order dated July 8, 1999 at 4; and Case No. 2000-00373, The Application of Jackson Energy Cooperative Corporation for an Adjustment of Rates, final Order dated May 21, 2001 at 11-12.

presented by both parties have been previously accepted.[54] Based on the reasoning set forth in LG&E's rebuttal testimony, we find the AG's trend analysis method to be the least appropriate method for determining this adjustment. However, there is another method in this record, one that compares year-end customers to a 13-month average, rather than a 12-month average, and it has also been accepted in the past.

The Commission finds that using a 13-month average is more appropriate to calculate the customer growth adjustment than the 12-month average proposed by LG&E. A 13-month average, which includes the last month immediately prior to the first month of a test year, better recognizes the number, or balance, of an item as of the beginning of the test year. This approach is used to derive average balances in other areas, such as materials and supplies, prepayments, and fuel inventories.

In response to a data request, LG&E provided revisions to its original adjustment to reflect a 13-month average.[55] Considering the arguments regarding the use of 12-month or 13-month averages, the Commission will accept the adjustment based on a 13-month average, as reflected in LG&E's data response. The result is an increase in electric revenues of $2,951,037 and an increase in electric operating expenses of $1,646,384. These amounts will be recognized in determining LG&E's revenue requirements.

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[54] Another approach that has also been accepted in prior cases is based on customer growth as measured by comparing the number of customers at the first of the year to those at the end of the year.

[55] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 28.

Depreciation Expense

LG&E proposed to increase its electric depreciation expense by $8,959,749 over its test-year actual level. This increase was based on its electric plant balances as of September 30, 2003, and the application of new depreciation rates as proposed in this proceeding. LG&E's new depreciation study was based on utility plant in service as of December 31, 2002 and was developed utilizing the Straight Line Method, the Broad Group Procedure, and the Average Remaining Life Technique.[56] LG&E's current depreciation rates were approved in Case No. 2001-00141 based on a settlement, and the depreciation study filed in that case was based on plant in service as of December 31, 1999.

The AG opposed LG&E's increase, citing several problems with the new depreciation rates as well as problems with some of the net salvage values included in those rates. The AG argued that the net salvage incorporated into LG&E's proposed depreciation rates was not reflective of the actual net salvage experienced by LG&E, included future inflation in the estimates of future net salvage expense, and included retirement costs that LG&E likely would never incur and had no legal obligation to incur.[57] The AG contended that LG&E's depreciation proposal is not consistent with FERC Order No. 631, which requires separate accounting for the cost of removal

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[56] Robinson Direct Testimony at 1 and 6.

[57] AG's Post-Hearing Brief at 15-20.

collected.[58] Lastly, the AG stated that the service lives used for several transmission and distribution plant accounts were incorrect.[59]

The AG recalculated the proposed depreciation rates by correcting the incorrect service lives and excluding the net salvage component. The AG proposed to recognize an annual net salvage allowance for LG&E, based on its actual 5-year average experience, in lieu of retaining the net salvage component in depreciation rates. The AG contended that the net salvage allowance is consistent with the requirements of FERC Order No. 631. Based on his recalculation, the AG proposed to reduce LG&E's test-year electric depreciation expense by $13,375,000.[60] The AG also suggested that $171,000,000 in overstated depreciation reserve should be returned to ratepayers over a 10-year period,[61] but he did not include this amount in his proposed depreciation adjustment.

LG&E disagreed with the AG's criticisms of the proposed depreciation rates. Concerning the treatment of net salvage, LG&E argued that the AG's approach would have the effect of deferring removal costs to the end of the life of the asset. This deferral would result in intergenerational inequities because customers who use the asset today are not paying the cost of removal today. Rather, those who are customers at the end of the asset life would have to pay the cost of removal.[62] Concerning the

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[58] Majoros Depreciation Direct Testimony at 28-29 of 51.

[59] Id. at 43-45 of 51.

[60] Henkes Electric Direct Testimony, Schedule RJH-8.

[61] AG's Post-Hearing Brief at 23.

[62] Joint Post-Hearing Brief of LG&E and KU at 43.

AG's claim that separating the net salvage component from depreciation rates is required by FERC Order No. 631, LG&E noted that this claim is not supported by the language in the FERC Order.[63] LG&E also stated that the AG's proposed net salvage allowance was rarely accepted by regulatory agencies and that the AG's citations to previous Commission decisions in electric cooperative cases did not disclose the entire decision.[64] Lastly, LG&E stated that the AG's selection of the longest available service lives for certain transmission and distribution assets reflected a "results-oriented" approach to determining depreciation rates.[65]

Based on a comprehensive review of both depreciation studies, the Commission has concerns about each of them. For LG&E's study, the Commission has concerns about the inclusion of an inflation adjustment for the removal costs. Depreciation methods inherently recognize inflationary effects, since the depreciation rates are based upon comparisons of the original cost of the asset to the current cost of removal. This recognition assumes that future inflation rates will be similar to historical inflation rates. If it can be adequately demonstrated that future inflation rates will be different from the historical inflation rates, an inflation adjustment would be reasonable. However, to properly reflect this change in inflation rates, the effects of inflation currently incorporated in the accumulated depreciation would need to be removed. In response to a data request, LG&E provided a revision of its proposed depreciation rates that did not include adjustments based upon future estimates of inflation or other judgmental

[63] Id. at 47.

[64] Id. at 43.

[65] Id. at 47-48.

factors.[66] After reviewing these rates, the Commission believes there are still problems related to the inflation adjustment that were contained in LG&E's initial depreciation study. Therefore, the Commission finds that LG&E's depreciation study should be rejected.

Concerning the AG's study, except for its recognition of LG&E's double counting of inflation, the Commission finds little justification for the AG's position and cannot accept his proposals as reasonable. The AG proposes that net salvage be based on a 5-year average. LG&E contends that the 5-year average is not appropriate because of intercompany transfers between LG&E and KU.[67] The Commission notes that the major reason for basing depreciation rates on an analysis of historical records is the expectation that the future is likely to follow trends that have occurred in the past. Therefore, it is not reasonable to use a 5-year average that contains unrepresentative data, but rather it would be more reasonable to use a longer time period in which such anomalies are likely to be averaged out.

The AG's claim that LG&E likely would never incur, or had no legal obligation to incur, the included retirement costs is irrelevant. The real question is whether it is reasonable to capitalize the cost of removal in order to recover those costs over the life of the investment. Capitalizing the cost of removal is a common practice and it has been accepted by this Commission for a number of years. The AG has not presented sufficient evidence in this case to persuade us to change this practice.

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[66] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 24(b), corrected in Robinson Rebuttal Testimony at 53 and Rebuttal Exhibit EMR-7.

[67] Robinson Rebuttal Testimony at 16.

The AG has also suggested that $171,000,000[68] of alleged over-stated depreciation reserve be amortized back to ratepayers over 10 years. What the AG seems to have not recognized is that when the remaining life technique is utilized, one of the early steps in the process of calculating remaining life rates is to calculate a theoretical reserve. The amount of deviation, whether positive or negative, of the actual reserves from the calculated theoretical reserves is then spread over the remaining life of the investment. Amortizing the deviation from the theoretical reserve over the remaining life of the investment is reasonable, and is normally incorporated into the depreciation rates. The performance of depreciation studies on a regular basis, including the determination of the current deviation from the theoretical depreciation reserve, is a reasonable alternative to an amortization over a fixed period of years.

The AG's extension of certain transmission and distribution asset service lives appears to be arbitrary rather than based on objective data. Depreciation estimates are just that - estimates. There are zones of reasonableness within which reasonable people will disagree. However, it is not reasonable to always select the service life that produces the lowest depreciation rates. Therefore, the Commission finds that the depreciation study submitted by the AG should also be rejected.

The Commission is especially concerned by the AG's interpretation of the provisions of FERC Order No. 631. As discussed above, FERC Order No. 631 generally adopted the provisions of SFAS No. 143. The AG's proposal to establish a

[68] The AG did not provide a schedule showing the determination of the $171,000,000 but instead references approximately 20 pages of detailed accounting printouts as the source of the figure. <u>See</u> Majoros ARO and SFAS 143 Direct Testimony at 21.

net salvage allowance relates to non-ARO assets, those assets for which LG&E does not have a legal retirement obligation. Concerning the removal costs associated with these non-ARO assets, FERC Order No. 631 states:

> 37. The purpose of this rule is to establish uniform accounting requirements for the recognition of liabilities for legal obligations associated with the retirement of tangible long-lived assets. <u>The accounting for removal costs that do not qualify as legal retirement obligations falls outside the scope of this rule.</u> The Commission is aware that there is an ongoing discussion in the accounting community as to whether the cost of removal should be considered as a component of depreciation. <u>However, this issue is beyond the scope of this rule and we are not convinced that there is a need to fundamentally change accounting concepts at this time.</u>
> 38. Instead we will require jurisdictional entities to <u>maintain separate subsidiary records for cost of removal for non-legal retirement obligations</u> that are included as specific identifiable allowances recorded in accumulated deprecation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. (emphasis added)

The language in FERC Order No. 631 clearly does not require the separation of the net salvage component from depreciation rates or the creation of a net salvage allowance as advocated by the AG. The requirement that separate subsidiary records be maintained is significantly different from requiring separation from depreciation rates.

Based on our findings to reject both of the depreciation studies submitted in this record, the Commission has normalized LG&E's test-year depreciation expense by applying its current depreciation rates to its utility plant in service as of September 30, 2003. This results in a reduction to LG&E's electric depreciation expense of $580,797.[69] The Commission further recognizes LG&E's willingness to file a new depreciation study by the earlier of its next general rate case or June 30, 2007, based

[69] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(a), page 4 of 7.

on plant in service as of a date no earlier than one year prior to the filing. This proposal is reasonable and will be accepted by the Commission.

Labor and Labor-Related Costs

LG&E proposed an increase in its electric labor and labor-related costs of $918,580. The proposed adjustment reflected the annualization of wages and salaries for the test year, the associated impact on payroll taxes, and an increase in the 401(k) company match.[70] When preparing the adjustment, LG&E assumed that Social Security and Medicare taxes would apply to 100 percent of the wage increase. It subsequently determined that at the end of year 2003, 98.72 percent of the wages did not exceed the Social Security wage limit, and it revised the increase proposed for the payroll taxes.[71]

The Commission believes that the labor adjustment should reflect the impact of the Social Security wage limit. The approach utilized by LG&E to determine the impact of this wage limit is reasonable. Based on this revised payroll tax adjustment, the Commission finds that LG&E's electric labor and labor-related costs should be increased by $917,916.[72]

[70] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.12.

[71] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(d)(3).

[72] The increase of $917,916 reflects an increase in wages of $837,128, plus a payroll tax increase of $63,376, plus an increase in the 401(k) company match of $17,412.

Pension and Post-Retirement Expenses

LG&E proposed to increase its test-year electric expense for pensions and post-retirement expenses by $2,755,476. LG&E claimed the adjustment was necessary to reflect the 2003 known and measurable expense changes determined by its actuary.

Initially, the AG did not propose a specific adjustment on pension and post-retirement expenses. However, in response to a data request, the AG recommended rejecting LG&E's adjustment and he revised his revenue calculation downward.[73] The AG opposed the pension and post-retirement expense adjustment proposed in the KU rate case, and stated in the LG&E rate case that consistency would dictate that KU and LG&E should be treated the same for rate-making purposes.[74]

The Commission notes that the AG submitted no testimony in this case on his recommendation to exclude LG&E's proposed adjustment for pension and post-retirement expenses, but instead relied on the testimony he filed in the KU rate case, Case No. 2003-00434. The Commission takes administrative notice of its findings and basis for rejecting the AG's position in that case, and affirms those findings in this proceeding. In that case, the AG argued that low interest rates and changes in the pension and post-retirement plan asset values contributed to the high level of expense that KU was seeking to recover. The Commission found that the AG had isolated only two of numerous factors that are considered in the very complex calculations required

[73] Response to the Commission Staff's First Data Request to the AG dated April 6, 2004, Item 5. The recognition of the exclusion of the proposed pension and post-retirement expense lowered the AG's recommended electric revenue increase from $12,141,000 to $9,366,000.

[74] Henkes Electric Direct Testimony at 54.

for pension and post-retirement benefit obligations and expenses. The Commission also cited the AG's lack of tangible evidence to support his assumptions and the absence of an explanation of how the circumstances relating to the pension adjustment he cited from Case No. 2000-00080 were applicable to KU's situation in that case. The Commission has in previous cases recognized the results of current actuarial studies in determining the reasonable level of pension and post-retirement expenses to include for rate-making purposes.[75] Here, LG&E has presented substantial evidence to support its adjustment and we find it persuasive. The Commission also notes that LG&E's pension and post-retirement plans are currently underfunded.[76] Therefore, the Commission finds that LG&E's proposal to increase its electric pension and post-retirement expense is reasonable and should be approved.

The Commission does have concerns about the underfunded status of LG&E's pension and post-retirement plans. LG&E should develop and implement a plan that eliminates the underfunding within a reasonable period of time. This plan should be filed with the Commission within one year from the date of this Order. In addition, LG&E should file progress reports describing the progress made in eliminating the underfunding of its pension and post-retirement plans. The progress reports should be filed every two years, and will be due with the filing of LG&E's annual financial report. The first progress report should be filed by March 31, 2007.

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[75] See Case No. 2000-00373, May 21, 2001 Order at 13-14 and Case No. 2001-00244, Adjustment of Rates of Fleming-Mason Energy Cooperative Corporation, final Order dated August 7, 2002 at 15-16.

[76] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 9.

Storm Damage Expense

LG&E proposed to normalize its storm damage expense by using a 10-year historic average adjusted for inflation. LG&E stated that this was the same methodology utilized by the Commission in Case No. 1990-00158. The normalization resulted in an increase of $70,492 over the test-year actual expense.

While the Commission agrees with the methodology used by LG&E, the inflation factor was not determined in a manner consistent with the approach used by the Commission in previous cases. The inflation factor previously used by the Commission is based upon the Consumer Price Index – All Urban Consumers ("CPI-U").[77] To determine the inflation factor for a particular year, the Commission divides the CPI-U for the base year by the CPI-U for the particular year.[78] The Commission has recalculated the storm damage expense adjustment using the inflation factor approach previously utilized, and determined that LG&E's storm damage expense should be increased by $83,765.

Rate Case Expense

When LG&E filed its electric rate case, it estimated that the total cost of the case would be $1,000,739. LG&E requested the recovery of its rate case expenses over a 3-year period, noting that this approach was consistent with previous Commission

[77] LG&E provided the CPI-U for the 10-year period in its response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(f).

[78] In this case, the base year is 2003. The calculation of the inflation factor for 2000 would take the CPI-U for 2003 divided by the CPI-U for 2000, in this example, 184.0 divided by 172.2. This results in an inflation factor for 2000 of 1.0685.

decisions. Based on the estimated rate case expenses, LG&E included a rate case expense of $333,580.

While the AG agreed with the approach of amortizing rate case expenses over 3 years, he questioned the level of estimated expenses and argued that the Commission should only allow the actual amount of prudently incurred rate case expenses. The AG calculated a rate case expense of $108,000, but acknowledged that this amount should be adjusted as LG&E documents additional, prudently incurred rate case expenses.[79] In its rebuttal testimony, LG&E agreed with the AG that this expense adjustment should be based only on actual expenses.[80] LG&E's latest update of actual electric rate case expenses total $687,778.[81]

The Commission agrees with both LG&E and the AG that only the actual, reasonable rate case expenses incurred in presenting this case should be recovered over a 3-year period. However, a review of LG&E's invoices for legal services reveals that the descriptions of services provided have been redacted for several line items on the basis that the information was protected by the attorney-client privilege.[82] LG&E later provided an affidavit of its counsel to affirm that the redacted legal services were

[79] Henkes Electric Direct Testimony at 41-43. The $108,000 reflects the first year of the 3-year amortization of total actual rate case expenses.

[80] Scott Rebuttal Testimony at 5-6.

[81] LG&E Updates of the Responses to the Commission Staff's First Data Request dated December 19, 2003, Items 43, 44, and 57, filed May 28, 2004. LG&E has provided supporting documentation for all rate case expenses reported throughout this proceeding.

[82] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 1, pages 11, 17, 20-21, and 24-28 of 160.

associated with this electric rate case.[83] The Commission recognizes and appreciates LG&E's right to assert its privilege to not disclose the nature of certain legal work performed by its attorneys. However, when a utility seeks to recover an expenditure in its rates, the Commission is obligated to review the nature of that expenditure to verify that it is just and reasonable. In this instance, we are unable to determine from the evidence of record the nature of certain legal services performed and whether those services were related to this rate case. Therefore, the Commission finds that $18,929 should be disallowed from the latest reported actual electric rate case expense. The Commission has calculated that the first year of a 3-year amortization of the actual electric rate case expenses is $222,950 and electric operating expenses have been increased by this amount.

Injuries and Damages

LG&E proposed to adjust its test-year expense for injuries and damages based on normalizing the actual expenses for a 5-year period, adjusted for inflation. LG&E used the same methodology that it proposed for adjusting its storm damage expense, except it excluded its test-year expenses and based the adjustment on the past 5 years rather than 10 years. LG&E determined its electric injuries and damages expense needed to be increased by $501,449. LG&E subsequently stated that a 10-year historical period would result in a better representation of normal expenses, and it recalculated the adjustment for injuries and damages using the same methodology as it

[83] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 3(d).

did for storm damage expense. The recalculation produced an increase in expense of $1,210,001.[84]

The AG agreed with LG&E's adjustment based on a 5-year period adjusted for inflation, but recommended including the test-year amount in calculating the 5-year average. The AG contended that including the test-year amount would result in a normalized expense based on the most recent actual data. The AG determined the increase in injuries and damages should be $430,000.[85]

The Commission finds it reasonable to calculate this adjustment using the same methodology used to determine the storm damage expense adjustment. Like storm damages, the injuries and damages expenses can fluctuate significantly from year to year. The 10-year historic average, adjusted for inflation, should produce a more reasonable ongoing level of expense. The recalculated adjustment in LG&E's rebuttal testimony used the same inflation factors as LG&E used in its storm damage expense adjustment. As discussed previously, the inflation factors were not determined in a manner consistent with previous Commission decisions. The Commission has calculated the 10-year historic average for injuries and damages, adjusted for inflation. Based upon this calculation, the Commission finds that LG&E's electric injuries and damages expense should be increased by $1,242,436.

Information Technology Staff Reduction

In October 2003, LG&E Energy Services, Inc. reduced its Information Technology staff by 27 employees. LG&E proposed an electric operating expense

[84] Scott Rebuttal Testimony at 6-7 and VLS Rebuttal Exhibit 2, page 1 of 2.

[85] Henkes Electric Direct Testimony, Schedule RJH-11, line 3.

reduction of $431,834, to reflect the savings from this staff reduction, offset by the first year of a 3-year amortization of the costs to achieve the reduction. LG&E determined the savings from the reduction based on payroll expense, payroll tax, and the 401(k) plan match.[86]

The AG agreed with the adjustment, but noted that LG&E had not recognized savings for the Team Incentive Awards ("TIA") and other employee benefits such as pension, post-retirement benefits, long-term disability, and various insurance coverages.[87] After including these additional employee savings, the AG increased LG&E's reduction from $431,834 to $674,834.[88]

The Commission agrees with the AG that the additional employee savings should be recognized in determining the employee reduction adjustment. The Commission finds that LG&E's electric operating expenses should be reduced by $673,403.[89]

Write-off of Obsolete Inventory

During the test year, LG&E wrote-off obsolete parts inventory totaling $2,060,448. LG&E proposed to defer this write-off and to amortize the cost over a 3-year period. LG&E argued that the costs incurred to purchase the inventory were

[86] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.26.

[87] Henkes Electric Direct Testimony at 45-46.

[88] Id., Schedule RJH-12. The AG determined the incremental increase in the reduction to be $243,000, which reflects 79 percent of the total additional employee savings of $306,990.

[89] The adjustment was recalculated using the format shown in Rives Exhibit 1, Schedule 1.26 and increasing line 7 by the additional total expense savings of $306,990. The 79 percent allocation factor for electric operations was applied to the net cost reduction to arrive at the $673,403.

prudent business expenditures and that allowing deferral and amortization of the costs would establish a representative, ongoing level of expenses. LG&E stated that this accounting treatment is consistent with the Commission's decision in Case No. 10064[90] concerning the early retirement of scrubbers and the abandonment of underground gas storage fields. Including the first year amortization, LG&E proposed an electric net operating expense reduction of $1,373,632.

The AG opposed this adjustment, contending that the write-off of obsolete inventory is a non-recurring event that should not be reversed by the means of a deferral and amortized through rates. The AG also argued that LG&E's proposed treatment of this adjustment was not consistent with LG&E's proposed adjustment for the Cane Run repair refund.[91]

The Commission is not persuaded by LG&E's claim that this proposed deferral and amortization is comparable with the early retirement and abandonment of utility plant addressed in Case No. 10064. The treatment prescribed in Case No. 10064 for the early retirement and abandonment of utility plant was the determination that those events constituted extraordinary property losses.[92] LG&E has provided no evidence in this proceeding to support the contention that the write-off of obsolete parts inventory constituted an extraordinary property loss. Consequently, it is not appropriate to defer this expense incurred in the test year and to amortize it over a period of years.

[90] Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company.

[91] Henkes Electric Direct Testimony at 46-47.

[92] Case No. 10064, July 1, 1988 Order at 17.

The Commission does recognize that a utility will experience from time to time the write-off of obsolete inventory. The amount written off will vary from year to year based on the circumstances surrounding the inventory becoming obsolete. We agree with LG&E that an objective of rate-making is to include reasonable, representative, ongoing levels of expenses that will be recovered through rates. The Commission finds that it is reasonable to adjust LG&E's expenses to include one-third of the test-year write-off of obsolete parts inventory. This amount will be included as a reasonable, representative, ongoing level of expense, and not as the amortization of a deferred cost. Therefore, the Commission finds that one-third of the test-year write-off of obsolete inventory should remain in electric operating expenses, thus resulting in a reduction of electric operating expenses of $1,373,632.

Write-off of Carbide Lime

During the test year, LG&E wrote-off the payment made to secure a supply of carbide lime for pollution control facilities at its Cane Run generating station. The supplier of the carbide lime had gone bankrupt, and the deposit on the contract was written off. LG&E proposed to reverse the write-off, to create a deferred debit, and to amortize the deferral over a 3-year period. After reflecting the first year of the 3-year amortization, LG&E proposed to reduce its electric operating expenses by $1,416,711. LG&E argued that while the cost was not expected to be of a recurring nature, it was prudently incurred, and incurred to benefit customers by securing material needed in the scrubber process. LG&E further argued that it should have the opportunity to recover this investment regardless of the frequency of write-offs.[93]

[93] Joint Post-Hearing Brief of LG&E and KU at 70.

The AG opposed the adjustment, arguing that the write-off was a non-recurring event that did not reflect a representative level of annual expense for rate-making purposes.[94]

Generally, the Commission has not permitted the deferral and future recovery of non-recurring costs that have been expensed in the test year. The Commission has made exceptions to this position when it has been demonstrated that consideration of other factors, such as the material nature of the costs, the future benefit of the costs to ratepayers and shareholders, and the proper matching of future benefits with the costs, has warranted different treatment.

The Commission is not persuaded by the arguments of LG&E. While LG&E stated that the carbide lime was needed for its scrubber process at the Cane Run generating station, the Commission notes that after October 2002, LG&E no longer carried an inventory of carbide lime.[95] LG&E has not explained why ratepayers should be required to pay for an investment in inventory that no longer exists on LG&E's books. In addition, LG&E has failed to demonstrate what future benefit to ratepayers or shareholders exists that warrants the deferral and amortization of this non-recurring expense.

Based on these findings, the Commission agrees with the AG that LG&E's proposal to defer and amortize its write-off of carbide lime should be rejected. The Commission has reduced electric operating expenses by $2,125,000. In addition, since

[94] AG's Post-Hearing Brief at 11.

[95] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 15(d)(3) and 15(d)(4), page 2 of 3.

LG&E currently does not maintain an inventory of carbide lime, and its contract for the supply of carbide lime has been terminated, the Commission will accept the AG's adjustment to LG&E's pro forma rate base to remove the carbide lime from the 13-month average of materials and supplies. This adjustment is shown in Appendix D.

Promotional Expenses

The AG proposed to reduce electric operating expenses by $90,450 to remove promotional expenses. The proposed adjustment reflected the balances in Account Nos. 909001, 909002, 912001, and 912005. The AG argued that the promotional expenses have not been included for rate-making purposes in previous Commission decisions and that the expenses failed to provide the "material benefit," as defined in 807 KAR 5:016,[96] necessary for their inclusion in rates.

LG&E disagreed with the portion of the AG's proposed adjustment that related to Account Nos. 912001 and 912005. LG&E argued that the expenses in Account No. 912001 related to economic development and did produce the "material benefit" envisioned in 807 KAR 5:016. LG&E noted that the commitments agreed to by LG&E and other parties in Case No. 2001-00104[97] required it to maintain a proactive stance on developing economic opportunities and supporting economic development. LG&E also argued that the expenses in Account No. 912005 related to customer satisfaction surveys and utility industry research that helps LG&E provide better customer service.

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[96] Henkes Electric Direct Testimony at 39-41.

[97] Case No. 2001-00104, Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance with E.ON AG's Planned Acquisition of Powergen PLC.

The AG disagreed with the reasons offered by LG&E in support of including Account Nos. 912001 and 912005 for rate-making purposes.[98]

The Commission has reviewed the accounts included in the AG's proposed adjustment. Concerning Account No. 909001, we do not agree with the AG's proposal to exclude the entire balance of this account. A significant portion of the account balance has been identified as conservation and safety advertising and customer information.[99] Conservation and safety advertising and customer information are considered under 807 KAR 5:016 to provide material benefits to ratepayers and are permitted to be included for rate-making purposes. Therefore, the amounts identified as conservation and safety advertising and customer information will not be excluded for rate-making purposes. Concerning Account No. 909002, the Commission agrees with the AG and will remove this expense balance for rate-making purposes.

Concerning Account Nos. 912001 and 912005, the Commission is not persuaded by LG&E's arguments. Account No. 912, Demonstrating and Selling Expenses, is defined as "the cost of labor, materials used and expenses incurred in promotional, demonstrating, and selling activities, except by merchandising, the object of which is to promote or retain the use of utility services by present and prospective customers."[100] Under the provisions of 807 KAR 5:016, Section 4(a), promotional advertising is stated as not producing a material benefit and such costs are expressly disallowed for rate-making purposes. Promotional advertising is defined in 807 KAR 5:016 as "any

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[98] AG's Post-Hearing Brief at 8.

[99] Response to the AG's First Data Request dated February 3, 2004, Item 229.

[100] 18 CFR 101 at 393. The USoA for electric utilities is codified as 18 CFR 101.

advertising for the purpose of encouraging any person to select or use the service or additional service of an energy utility, or the selection or installation of any appliance or equipment designed to use such utility's service."[101] The definition of Account No. 912 clearly falls within the definition of promotional advertising, which cannot be included for rate-making purposes.

In addition, the commitments in Case No. 2001-00104 do not unconditionally justify the inclusion of expenses LG&E contends are related to economic development. Commitment No. 43 states, as follows:

> 43. E.ON and PowerGen commit to maintaining LG&E's and KU's pro-active stance on developing economic opportunities in Kentucky and supporting economic development, and social and charitable activities, throughout LG&E's and KU's service territories.[102]

While the commitment requires LG&E to continue supporting economic development, nothing in the commitment addresses the recovery of the expenses which are the subject of the commitment.

The Commission will take this opportunity to reaffirm its support of economic development activities. However, in this proceeding, LG&E has not provided sufficient evidence to demonstrate that the expenses in Account No. 912001 are actually related to economic development. Therefore, the Commission finds that LG&E's electric operating expenses should be reduced by $79,997.

[101] 807 KAR 5:016, Section 4(b).

[102] Case No. 2001-00104, final Order dated August 6, 2001, Appendix A at 11.

Miscellaneous Expenses

The AG proposed an adjustment to reduce miscellaneous expenses by $218,361.[103] The AG's proposed adjustment was comprised of three items. First, he removed charitable contributions that LG&E had recorded in accounts other than Account No. 426. Second, he removed 50 percent of test-year electric operating expenses associated with employee gifts, award banquets, parties, and other social events based on his understanding of previous Commission decisions that these types of employee expenses are not normally included for rate-making purposes. Lastly, he recommended that 72.16 percent of LG&E's dues paid to the Edison Electric Institute ("EEI") should be disallowed, an amount of $141,001, based on a claim that the portion of the EEI dues dedicated to legislative advocacy, regulatory advocacy, legislative and regulatory policy research, institutional advertising and marketing, and public relations produced no benefit to ratepayers and should be borne by LG&E's stockholders.[104]

LG&E agreed that the charitable contributions that had been recorded in error in accounts other than Account No. 426 should be removed for rate-making purposes.[105] LG&E strongly disagreed with the AG's adjustment to remove the expense of employee gifts, award banquets, and social expenses, arguing that those expenses were prudent and reasonable and should be charged to ratepayers because they reward employees

[103] Henkes Electric Direct Testimony, Schedule RJH-15. The AG also included on this schedule an adjustment to reflect the full year impact of the environmental surcharge roll-in. That adjustment was addressed previously in this Order.

[104] Id. at 49-50.

[105] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 34.

in connection with LG&E's safety programs and professional achievements and accomplishments. LG&E further argued that these expenses contribute to the morale of employees and provide incentives to encourage high levels of performance.[106] Concerning the EEI dues, LG&E agreed that the portion associated with legislative advocacy and public relations should be excluded for rate-making purposes, but the portion associated with the other activities were reasonable to include for rate-making purposes. LG&E proposed that 31.55 percent of its EEI dues, or $61,649, should be excluded.[107]

The Commission agrees that the charitable contributions should be excluded for rate-making purposes. The AG assumed that 80 percent of the total contributions were applicable to LG&E's electric operations. Based on LG&E's 2003 Common Utility Study, the Commission has concluded that 87 percent is the appropriate level to allocate to LG&E's electric operations. Therefore, the Commission finds that electric miscellaneous expenses should be reduced by $19,528 for this item.

The Commission agrees with the AG that the expenses for employee gifts, award banquets, and social events should be excluded for rate-making purposes. In previous cases,[108] the Commission has not included these types of costs when determining

[106] Scott Rebuttal Testimony at 8.

[107] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 11.

[108] See Case No. 1990-00041, An Adjustment of Gas and Electric Rates of The Union Light, Heat and Power Company, final Order dated October 2, 1990 at 28-29; Case No. 1997-00066, An Adjustment of General Rates of Delta Natural Gas Company, Inc., final Order dated May 1, 1998 at 16-17; and Case No. 2001-00244, August 7, 2002 Order at 27-28.

rates, and LG&E has not provided adequate justification to support a different treatment. In addition, the Commission notes that emphasis on safety and incentives to encourage employee performance are incorporated into LG&E's TIA program. LG&E did agree that there was some overlap between the TIA program and the purpose for these expenses.[109] However, while agreeing with the AG that these expenses should be excluded for rate-making purposes, we find there is no basis for the AG's proposal to exclude only 50 percent of the test-year level. Therefore, the Commission finds that 100 percent should be excluded, thereby reducing electric miscellaneous expense by $118,805.

The Commission supports LG&E's efforts to reinforce the need for safety among their employees and encourages LG&E to develop appropriate safety programs. In future rate cases, the Commission will reconsider the treatment of safety-related awards to the extent that LG&E can provide adequate documentation to show that these awards and other activities are integral components of a formal safety program.

Concerning the EEI dues, the Commission has reviewed the description of the various activities funded by the EEI dues,[110] and finds that the portion of the dues associated with legislative advocacy, regulatory advocacy, and public relations should be excluded for rate-making purposes. The description of regulatory advocacy appears to be a form of lobbying activity, which the Commission has not included for rate-making purposes in previous cases. These three categories account for 45.35 percent of the

[109] T.E., Volume II, May 5, 2004, at 176.

[110] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 44.

EEI dues.[111] Applying the 45.35 percent exclusion to the test-year EEI dues results in a reduction of $88,614.[112]

During the test year, LG&E had allocated $15,097 in expenses associated with EEI conferences to its gas operations. Based on a review of the conference descriptions, we cannot accept LG&E's contention that a portion of these conference expenses should be allocated to gas operations.[113] The Commission finds that LG&E's allocation of these EEI conference expenses should be reversed, with all EEI conference expenses charged to LG&E's electric operations. This results in an increase in electric operating expenses of $15,097. The Commission further finds that, unless LG&E can adequately document otherwise, all expenses associated with EEI activities should be charged to electric operations.

Based on these conclusions, the Commission has reduced electric miscellaneous expenses by $211,850.

Kentucky Income Tax Rate

LG&E determined that its federal and Kentucky income tax expense would be reduced by $27,540,380, based upon its proposed adjustments to electric revenues and

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[111] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 11, page 2 of 3.

[112] EEI dues of $195,401 times 45.35 percent equals $88,614.

[113] Response to the AG's First Data Request dated February 3, 2004, Item 313. The largest single conference expense allocated to gas operations, in the amount of $13,194, was related to the Utility Air Regulatory Group, which provided Clean Air Act representation and monitoring of regulatory issues to electric utilities before the Environmental Protection Agency and the federal courts. LG&E agreed that allocating this conference expense to gas operations was in error, See T.E., Volume II, May 5, 2004, at 175.

expenses. LG&E's calculation reflected the use of the statutory federal income tax rate of 35 percent and the statutory Kentucky income tax rate of 8.25 percent.

The AG proposed that LG&E's effective Kentucky income tax rate for tax year 2002 of 7.87 percent should be used in all income tax and income tax-related calculations. The effective Kentucky income tax rate results from LG&E's ability to file a consolidated Kentucky corporate income tax return. The AG noted that the Commission adopted the use of the effective Kentucky income tax rate for The Union Light, Heat and Power Company's ("ULH&P") last rate case on a trial basis. The AG stated that the Commission's expressed concern in the ULH&P case about using the effective Kentucky income tax rate should not be a concern here since LG&E's effective Kentucky income tax rates over the last 4 years were nearly constant. The AG argued that the use of the effective tax rate should be extended to LG&E so its ratepayers can receive the benefit of the reduction in income taxes resulting from the filing of consolidated tax returns. However, the AG noted that in addition to applying the effective Kentucky income tax rate to the adjustments accepted in this proceeding, it would be necessary to adjust the level of income taxes included in the determination of test-year-actual net operating income, since the taxes would still be based upon the statutory Kentucky income tax rate.[114]

LG&E opposed this recommendation, noting that the Commission has always used the statutory tax rate and that consistent treatment should be afforded to LG&E. LG&E argued that the effective tax rate reflects the impacts of credits and apportionment adjustments from out-of-state activities, which could change in the future.

[114] AG's Post-Hearing Brief at 4-5.

LG&E stated that the use of the effective tax rate would ignore the fact that it pays Indiana tax on a portion of its off-system sales. If the effective tax rate is to be used, LG&E reasoned, the Indiana tax of 8.07 percent should be included in the determination of the effective tax rate.[115]

In Case No. 2001-00092,[116] ULH&P proposed to use its effective Kentucky income tax rate in the calculation of all income tax and income tax-related adjustments. Kentucky income tax law permits corporations such as LG&E to file consolidated Kentucky corporation income tax returns.[117] Under this approach, the E.ON US Investment Corporation's net taxable income is apportioned to Kentucky based on a weighted property, payroll, and receipts factor. The effective Kentucky income tax rate is a result of this apportionment of income plus the inclusion of companies that would not have filed a Kentucky return, except for the fact that they were members of the E.ON US Investment Corporation consolidated group.

The Commission in not persuaded by the AG's arguments. Case No. 2001-00092 was a gas operations only rate case, and there was no issue related to out-of-state taxation of off-system sales, and, of particular note, ULH&P expressly requested the use of the effective income tax rate. Here, LG&E expressly opposes using the effective tax rate. We do agree with the AG's position that if the effective income tax rate is utilized, there would have to be an adjustment to the test-year-actual income tax

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[115] Rives Rebuttal Testimony at 9-10.

[116] Case No. 2001-00092, An Adjustment of Gas Rates of The Union Light, Heat and Power Company.

[117] See KRS 141.200 and 103 KAR 16:200.

expense shown in LG&E's operating statement. The existence of the Indiana tax on off-system sales would have to be addressed in such an adjustment, and the record in this proceeding does not contain sufficient information to accurately do so. Therefore, the Commission finds that the statutory Kentucky income tax rate should be utilized for all income tax and income tax-related adjustments in this rate case. However, the Commission notes that it will be reviewing the use of the effective tax rate in ULH&P's next rate case. In LG&E's next rate case, it should address in detail the use of the effective tax rate for rate-making purposes.

Based upon these findings and the Commission's determination of the electric revenue and expense adjustments, the Commission has reduced LG&E's electric income tax expense by $23,794,268.

Interest Synchronization

LG&E originally proposed to reduce its interest expense by $98,001, which resulted in an increase to income tax expense of $39,556.[118] LG&E stated that it followed the methodology used by the Commission in Case No. 2000-00080. LG&E multiplied its proposed adjusted electric capitalization by its proposed weighted average cost of debt to determine its normalized interest expense. The normalized interest expense was then compared to the test-year actual interest expense per LG&E's books. During the proceeding, LG&E discovered several errors in its calculations. The result of LG&E's corrections was an increase in its interest expense of $1,008,247, and a corresponding decrease in income tax expense of $406,954.[119]

[118] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.37.

[119] Rives Rebuttal Testimony, SBR Rebuttal Exhibit 2.

The AG agreed with LG&E's methodology and recognized the corrections identified by LG&E. The AG calculated his adjustment using a composite federal and Kentucky income tax rate that reflects the effective Kentucky income tax rate, rather than the statutory tax rate. The AG determined that LG&E's income tax expense should be decreased by $403,000.[120]

The Commission has recalculated the interest synchronization adjustment, reflecting the debt components of LG&E's electric capitalization, the corresponding interest cost rates found reasonable in this Order, and the statutory Kentucky income tax rate. The Commission has determined that LG&E's electric interest expense should increase $563,647, resulting in a reduction in income taxes of $227,502.

Pro Forma Net Operating Income Summary

After consideration of all pro forma adjustments and applicable income taxes, the adjusted net operating income for LG&E's electric operations is as follows:

Operating Revenues	$726,815,085
Operating Expenses	653,002,752
Adjusted Electric Net Operating Income	$ 73,812,333

RATE OF RETURN

Capital Structure

LG&E proposed an adjusted test-year-end electric capital structure containing 40.74 percent long-term debt, 3.84 percent short-term debt, 3.82 percent accounts receivable securitization, 3.60 percent preferred stock, and 48.00 percent common

[120] Henkes Electric Direct Testimony, Schedule RJH-5.

equity.[121] As discussed previously in this Order, LG&E has allocated several adjustments to its capitalization on a pro rata basis or to common equity only as it determined appropriate.[122] During the proceeding, LG&E stated it had considered the Commission's policy of recognizing the impact on capital cost and capital structure of significant post-test-year issues of debt or equity. LG&E has updated its capital structure to reflect post-test-year changes, with the last update reflecting financial information as of March 31, 2004.[123] Using this latest financial information, LG&E determined its capital structure as 41.91 percent long-term debt, 5.01 percent short-term debt, 3.58 percent preferred stock, and 49.50 percent common equity. This updated capital structure did not reflect an adjustment for LG&E's minimum pension liability as of December 31, 2003. In March 2004, LG&E applied the accounting decision announced by FERC concerning the creation of a regulatory asset to reverse the impact of the minimum pension liability.

The AG proposed an adjusted test-year-end electric capital structure for LG&E containing 41.45 percent long-term debt, 3.90 percent short-term debt, 3.89 percent accounts receivable securitization, 3.66 percent preferred stock, and 47.10 percent

[121] Rives Direct Testimony, Rives Exhibit 2, page 1 of 2.

[122] LG&E allocated adjustments for JDIC, the removal of 25 percent of inventories associated with Trimble County Unit 1, its equity investment in OVEC, the removal of reimbursed capital invested to repair combustion turbines at the E. W. Brown Generating Station, and the removal of its Post-1995 environmental compliance plan investments on a pro rata basis to all components of capitalization. The proposed adjustment for the minimum pension liability to Other Comprehensive Income was allocated to common equity only.

[123] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 10. LG&E's update that reflected financial information as of March 31, 2004 was filed with the Commission on April 29, 2004.

common equity.[124] The only difference from LG&E's proposal was that the AG rejected LG&E's treatment of the minimum pension liability. The AG did not oppose LG&E updating its capital structure, but the AG did state that the capital structure ratios could be updated beyond the test year only if the changes were minor so that any change in the company's financial risk would also be minor. Changes beyond the test year that affected the financial risk should not be allowed, according to the AG.[125]

In December 2000, the Commission approved LG&E's 3-year pilot accounts receivable securization program in Case No. 2000-00490.[126] At the end of the pilot period, LG&E decided not to seek a continuation of the program, and consistent with the decision in Case No. 2000-00490, the accounts receivable securization program was terminated on January 16, 2004. LG&E replaced the funding provided by the accounts receivable securization program with a mix of short-term and long-term debt from Fidelia, Inc. ("Fidelia").[127]

As correctly noted by LG&E, the Commission in previous cases has recognized the impact on the capital structure of significant post-test-year issues of debt or equity in order to determine the appropriate capital structure. Consequently, the Commission finds it reasonable to recognize the termination of the accounts receivable securization

[124] Henkes Electric Direct Testimony, Schedule RJH-2.

[125] Weaver Testimony at 77-78.

[126] Case No. 2000-00490, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving the Transfer of Certain Financial Assets, final Order dated December 13, 2000.

[127] Fidelia is owned by E.ON North America Inc. and E.ON US Holding GmbH, which are subsidiaries of E.ON. See Response to the Commission Staff's First Data Request dated December 19, 2003, Item 2.

program and the issuance of debt from Fidelia in the determination of LG&E's capital structure.

However, we do not agree with LG&E's proposal to simply use the updated capital structure as of March 31, 2004. Unlike its debt, LG&E did not issue any new shares of common stock. The March 31, 2004 financial information reflects the current level of net income from operations in Retained Earnings. As discussed previously in this Order, the Commission has recognized the adjustment to test-year-end common equity for the minimum pension liability. That minimum pension liability reflected the determination made at December 31, 2002. The application of the FERC accounting decision and creation of the regulatory asset reflected in the March 31, 2004 financial information reflect a minimum pension liability determined as of December 31, 2003. If the Commission were to use the capital structure based on the March 31, 2004 financial information, there would be a mismatch related to the minimum pension liability. The Commission's decision to allow the reversal of the December 31, 2002 minimum pension liability to common equity is the appropriate means of handling this issue, and it should be recognized in the capital structure.

As shown in Appendix E, the Commission finds LG&E's electric capital structure is as follows:

	Percent
Long-Term Debt	42.58
Short-Term Debt	5.17
Preferred Stock	3.65
Common Equity	48.60
Total Electric Capital Structure	100.00

Cost of Debt and Preferred Stock

LG&E proposed a cost of long-term debt of 3.77 percent, short-term debt of 1.06 percent, accounts receivable securization of 1.39 percent, and preferred stock of 2.51 percent.[128] As noted previously, LG&E filed updated financial information as of March 31, 2004 that included updated cost rates. Based on this updated information, LG&E's cost of long-term debt is 3.57 percent, short-term debt is 1.54 percent, and preferred stock is 2.59 percent.[129]

The AG used LG&E's costs of debt and preferred stock as filed in its application. The AG agreed that if interest rates or other capital cost rates change, such changes should be used to determine the rate of return so that LG&E will have a reasonable opportunity to earn its allowed return.[130]

The Commission finds it appropriate to recognize the cost rates for debt and preferred stock as of March 31, 2004 when determining the overall cost of capital for LG&E's electric operations. Updates to LG&E's debt and preferred stock cost rates constitute known and measurable adjustments and using these updates, rather than the test-year-end cost rates, is more representative of the period in which the rates established in this Order will be in effect. These cost rates will be applied to the electric capital structure determined herein. Therefore, the Commission finds the cost of long-

[128] Rives Direct Testimony, Rives Exhibit 2, page 1 of 2.

[129] Updated Monthly Response to the Commission Staff's First Data Request dated December 19, 2003, Item 43, filed April 29, 2004.

[130] Weaver Testimony at 77.

term debt to be 3.57 percent, short-term debt to be 1.54 percent, and preferred stock to be 2.59 percent.

Return on Equity

LG&E estimated its required return on equity ("ROE") using four methods: the capital asset pricing model ("CAPM"), the discounted cash flow method ("DCF"), two risk premium analyses, and a comparable earning approach.[131] The CAPM analysis includes an adjustment of 60 basis points in order to recognize a size premium for some of the low- and mid-capitalization companies in its comparison group. LG&E explained that it employed multiple methods in determining its cost of equity because of potential measurement errors in the models as a result of industry changes, such as merger activity and price volatility.

LG&E performed separate analyses on its electric and gas operations; however, with the settlement of the gas-related issues, LG&E withdrew the ROE testimony for its gas operations. Based on the results of the four methods, LG&E recommends an ROE range for its electric operations of 10.75 to 11.25 percent.[132] LG&E recommends awarding the upper end of the range, 11.25 percent, in order to recognize its efficient operations and the current uncertain business climate for utilities.[133]

LG&E employed a proxy group in its analysis, consisting of electric utility companies similar in risk to its electric operations. LG&E proposed the use of proxy companies because, as a subsidiary of LG&E Energy, it is not publicly traded. The

[131] Rosenberg Direct Testimony at 2.

[132] Id.

[133] Id. at 4.

companies were selected from the Electric Utility category of *The Value Line Investment Survey*. The selected companies had to have overall senior bond ratings of Aa/A from Moody's Investor Service and AA/A from Standard & Poor's ("S&P") rating service and could not be currently involved in major merger activity. Companies were also excluded if they had significant unregulated operations, if they did not pay a dividend or if they expected to cut their dividend.

As part of its analysis, LG&E provided a discussion of the role that ROE plays in how the financial community regards a utility company. LG&E states that accounting scandals, federal and state investigations, and other negative fallout from the collapse of Enron have shaken investor confidence in the energy industry. The result is more intense scrutiny of companies and a scarcity of financing at a time when many energy companies need to refinance billions of dollars of debt. At the time of its application, LG&E stated that S&P had reported 41 utility issuer credit rating downgrades, as compared to only eight upgrades during 2003. Moody's had downgraded roughly a third of the utilities it follows, as compared to the 10 percent annual average downgrades it had issued over the past 19 years. LG&E argued that these actions indicate less tolerance for financial weakness in a utility and that they have increased the cost of financing to weaker companies. In support of its argument, LG&E provided several citations from S&P publications that described the authorized returns for the regulated electric industry as insufficient and discussed the importance of profit potential and earning power in both credit protection and a company's ability to withstand business adversity.[134]

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[134] Id. at 7-9.

The AG criticized LG&E's ROE estimates on several grounds. The AG disagreed with several of the methodologies and inputs used by LG&E and with LG&E's small cap adjustment in the CAPM model. Two points which the AG identified as "fatal errors" were: (1) LG&E should not have used the Consumer Price Index ("CPI") when working with the Gross Domestic Product ("GDP") data; and (2) LG&E should have multiplied projected GDP growth and projected inflation growth instead of adding.[135] The AG argues that the small cap adjustment is already in the market prices of the mid- and low-capitalization companies used in the analysis and he concludes that LG&E's flawed analysis overstates its required cost of equity.

The AG estimated LG&E's required ROE using three methods: the CAPM, the bond-yield-plus-risk premium approach, and two versions of the DCF model.[136] The analyses were performed separately for LG&E's electric operations. Based on the results of these methods, the AG determined an ROE range of 9.75 to 10.25 percent for LG&E's electric operations, recommending that the Commission award 10.00 percent, the mid-point of the range.[137] During the hearing, the AG's witness stated that he would change his recommendation from 10.00 percent to 10.25 percent if LG&E's ESM is eliminated as proposed in the settlement of this issue.[138]

The AG employed a proxy group in his analysis, consisting of utility companies classified as electric utilities by *Value Line*. The AG eliminated companies with a

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[135] Weaver Testimony at 8.

[136] Id. at 32.

[137] Id. at 75.

[138] T.E., Volume III, May 6, 2004, at 177-179.

Financial Strength Rating below B, that *Value Line* did not recommend to investors, that had recently sold or purchased major assets, divested the majority of their generation plant, were involved in merger activity, or had a short operating history. The AG excluded Hawaiian Electric because it is not interconnected and also excluded any companies with a heavy reliance on hydro, nuclear or purchased power. Finally, the AG did not include any companies whose electric revenues as a percentage of total revenues were too dissimilar to that of LG&E.

The AG supported his analysis with a discussion of the economic conditions that would affect the ROE he recommended. He reviewed the GDP, inflation rates, interest rates and leading economic indicators. The AG believes that the GDP growth rate is within a range ideal for investment growth, that inflation is expected to continue to be low, and that interest rates are expected to be stable yet gradually increasing over the next 4 years. The AG concluded that the cost of equity for electric utilities would slowly increase over the near-term future. In fact, he made an adjustment in his DCF model to increase the results by 95 basis points to recognize an expected increase in interest rates.

On rebuttal, LG&E questioned the AG's recommended range since it differed by 50 to 100 basis points from the range recommended by this same witness in the ESM case, which was consolidated into this rate case. In his ESM testimony, the AG recommended a range of 10.25 to 11.25 percent, just 3 months prior to filing rate case testimony in which he recommends 9.75 to 10.25 percent.[139] In response to questions about how LG&E's risk had changed since the ESM case, the AG responded that the

[139] Rosenberg Rebuttal Testimony at 4.

risk had changed very little.[140] To further demonstrate that the AG's recommendation is too low, LG&E compared the AG's recommendation to the 11.00 percent average electric ROE awarded nationally by utility regulatory commissions in 2003.[141]

In rebutting the AG's recommendation, LG&E stated that the AG's analysis employs misstated and misapplied approaches. LG&E identified calculations that it considers incorrectly performed and, when corrected, produce a higher result. LG&E also addressed the two "fatal errors" that the AG identified in LG&E's analysis. LG&E defended its use of inputs, reiterating that: (1) its use of the CPI as a measure of inflation was appropriate; and (2) the AG's contention that it had added rather than multiplied in the GDP calculation was, in fact, incorrect.[142]

The Commission finds merit in both LG&E's and the AG's recommended ranges for ROE and their critiques of each other's analyses. The Commission takes note of several sources of agreement between LG&E and the AG. As LG&E points out in its rebuttal testimony, the AG's recommended range in the consolidated ESM case overlaps substantially with LG&E's recommended range. The Commission also takes note of the AG's upward revision to his recommendation due to the agreement to discontinue the ESM mechanism. LG&E recommended the top of its range in order to recognize its efficient management and the uncertain business environment. While the Commission is prohibited from using an ROE award to either reward or punish a utility's

[140] Response of the Attorney General to Requests for Information from LG&E, dated April 6, 2004, Item 32.

[141] Rosenberg Rebuttal Testimony at 2.

[142] Id. at 15-16.

management,[143] the Commission again takes note that the AG supported, in part, the need to increase the ROE award in recognition of the uncertain business climate when he increased some of his results by 95 basis points to allow for likely increases in interest rates in the near future. Finally, the Commission notes that LG&E has compared the returns on equity recommended by the intervenors to recent returns on equity allowed by regulators in other jurisdictions. LG&E states that an April 5, 2004 edition of *Major Rate Case Decisions* of Regulatory Research Associates reports an average allowed return for electric utilities in other jurisdictions of 11 percent in the first quarter of 2004.[144] The Commission takes notice that this same publication subsequently reported in May 2004 that the allowed returns on equity for electric utilities in other jurisdictions ranged from 9.50 percent to 11.22 percent.[145] While we agree with LG&E when it says that ROE awards granted by other commissions should not dictate this Commission's decision, those decisions do, however, indicate that the recommendations from both parties are well within the general level of recent allowed returns. Therefore, after weighing all the evidence of record, the Commission finds that LG&E's required ROE falls within a range of 10.00 percent to 11.00 percent with a midpoint of 10.50 percent.

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[143] South Central Bell Telephone Company v. Utility Regulatory Commission, Ky., 637 S.W. 2d 649 (1982).

[144] Rosenberg Rebuttal Testimony at 2.

[145] Regulatory Research Associates, Inc., Regulatory Focus, May 26 and May 28, 2004.

Rate of Return Summary

Applying the rates of 3.57 percent for long-term debt, 1.54 percent for short-term debt, 2.59 percent for preferred stock, and 10.50 percent for common equity to the capital structure produces an overall cost of capital of 6.79 percent. The cost of capital produces a rate of return on LG&E's electric rate base of 6.69 percent.

REVENUE REQUIREMENTS

The Commission has determined that, based upon an electric capitalization of $1,484,965,466 and an overall cost of capital of 6.79 percent, the net operating income that could be justified by the record for LG&E's electric operations is $100,829,155. Based on the adjustments found reasonable herein, LG&E's pro forma electric net operating income for the test year would be $73,812,333 and LG&E would need additional annual operating income of $27,016,822. After the provision for uncollectible accounts, the PSC Assessment, and state and federal income taxes, LG&E would have a revenue deficiency of $45,608,365. The calculation of this overall revenue deficiency is as follows:

Net Operating Income Found Reasonable	$100,829,155
Pro Forma Net Operating Income	73,812,333
Net Operating Income Deficiency	27,016,822
Gross Up Revenue Factor[146]	.5923655
Overall Revenue Deficiency	$ 45,608,365

[146] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.39. The gross up revenue factor recognizes the impact the overall revenue deficiency will have on the provision for uncollectible accounts, the PSC Assessment, Kentucky income taxes, and federal income taxes.

However, as discussed above, LG&E is a signatory to the Partial Settlement and Stipulation. Thus, LG&E has indicated its willingness to accept an increase in electric annual revenues of $43,400,000. In determining the overall reasonableness of this alternative proposed increase by LG&E, the Commission has devoted a significant portion of this Order to evaluating LG&E's and the AG's proposed adjustments to capital, rate base, operating revenues, and operating expenses in light of our normal rate-making treatment.

The Commission has found that LG&E's required ROE falls within a range of 10.00 percent to 11.00 percent. Applying the findings herein on the reasonable costs of debt and preferred stock, and the range of return on common equity, to LG&E's electric capitalization would result in the following range of revenue increases:

Revenue Increase -- 10.00 percent ROE	$39,591,950
Revenue Increase -- LG&E Alternative Proposal	$43,400,000
Revenue Increase – Justifiable by Record	$45,608,365
Revenue Increase -- 11.00 percent ROE	$51,875,465

Based on the findings and conclusions herein, the Commission finds that the earnings resulting from the adoption of LG&E's alternative proposal for its electric operations will fall within a range reasonable for both LG&E and its electric ratepayers. The $43,400,000 electric revenue increase that LG&E is willing to accept will result in fair, just, and reasonable electric rates for LG&E. Therefore, the Commission will accept LG&E's alternative proposal that its electric revenues be increased by $43,400,000.

FINDINGS ON PARTIAL SETTLEMENT AND STIPULATION

Based upon a review of all aspects of the unanimous provisions in the Partial Settlement and Stipulation, an examination of the record, and being otherwise sufficiently advised, the Commission finds that the unanimous provisions are in the public interest and should be approved. These provisions include, but are not limited to, the VDT surcredit, a new HEA program, the dismissal of two specified court appeals, and the phase-out of the Pay As You Go program. The Commission's approval of the unanimous provisions is based solely on their reasonableness in toto and does not constitute precedent on any issue except as specifically provided for therein. Although we are approving all of the unanimous provisions, we have some concerns that need to be addressed at this time regarding certain aspects of those provisions.

Electric Residential Rate Design

The parties have agreed to eliminate LG&E's seasonal residential electric rates. Historically, LG&E's residential rates have been set at higher levels during the peak summer months of June through September than during the rest of the year. Due to the impact of residential air conditioning use on LG&E's summer peak demand, this rate design was implemented to encourage conservation during the summer peak season. While the Commission does not object to eliminating this peak season differential, we are concerned that it might have an adverse impact by causing LG&E's peak demand to increase. Therefore, we find that LG&E should be required to monitor its summer demand, beginning July 1, 2004 and continuing through September 30, 2006 to ascertain the impact on its demand, if any, resulting from this rate design change. We also find that LG&E should, within 90 days of the end of this monitoring period, prepare a brief analysis and report summarizing the results of its monitoring.

LG&E should compare the actual growth in its residential summer demand to the growth it has forecast for its residential summer demand. While many factors can affect the difference between actual and forecast demand growth, LG&E should determine whether any unanticipated growth is the result of the change to a single year-round energy rate for residential customers. The Commission will convene an informal conference with LG&E within 90 days of the end of this monitoring period in order to facilitate an informal review of LG&E's analysis. The Commission will, at that time or earlier if conditions warrant, determine the need to evaluate the impact that this rate design change may have on LG&E's summer peak demand and investigate whether the seasonal residential rates should be re-implemented.

New HEA Program

The Commission's approval of the unanimous provisions in the Partial Settlement and Stipulation includes the approval of the parameters of a new HEA program for LG&E. The HEA program will be funded by a 10-cent per residential meter per month charge for a period of 3 years. An electric or gas only residential customer of LG&E will pay 10 cents per month while a combined electric and gas customer will pay 20 cents per month. The charge will be set forth as a separate line item on each residential customer's bill.

The Commission certainly recognizes that low income households frequently have difficulties paying their utility bills. Consequently, financial assistance programs that subsidize the utility bills of those households are much needed. However, when these types of programs are funded through mandatory charges on residential utility bills, the common perception is that these charges are forced charitable contributions and they generate sincere objections from many ratepayers. While it will never be possible to eliminate every objection, ratepayers will certainly have a higher degree of acceptance of the funding for these programs if they can be assured that the funds collected will be fully accounted for and spent in the most efficient manner.

It is for this reason that the Commission has always urged the utility that will be the beneficiary to be a financial contributor to the assistance program. When an affected utility is at least partially funding an assistance program, the utility has a greater incentive to monitor the program expenditures and is in a better position to assure its ratepayers that the funds are being spent in the most efficient manner. Consequently, the Commission is disappointed that LG&E has chosen not to be a financial contributor to the HEA program which it has agreed to implement. We urge LG&E to reconsider this decision, but we recognize that we have no authority to require LG&E to fund such a program.

In any event, there is a real need for LG&E to actively monitor the implementation, operation, and expenditures of the HEA program. The Commission expects LG&E to fulfill this role so it can provide its ratepayers with the assurances they demand and deserve regarding the efficient expenditure of the HEA funds.

The Partial Settlement and Stipulation did not address when the 10-cent per residential meter per month charge would begin. The Commission does not believe it would be reasonable for this charge to begin on the same effective date as the rates contained in the Partial Settlement and Stipulation, primarily because the programmatic details of the HEA program have not been submitted to the Commission for approval as agreed to by the parties. The Commission finds that the HEA program 10-cent per residential meter per month charge should not be collected from ratepayers until the Commission has approved the programmatic details. The Partial Settlement and

Stipulation envisions the HEA program to have a commencement date of October 1, 2004. The Commission believes it will need 60 days to review the programmatic details. Therefore, the Commission expects that the programmatic details for the new HEA program would be submitted for approval no later than August 1, 2004.

In addition, prior Commission Orders outlined several concerns about previous HEA programs in the Orders in Case No. 2001-00323.[147] The Commission continues to have those same concerns, and expects the proponents of this new HEA to address those concerns when the programmatic details are submitted to the Commission for its review and approval.

OTHER ISSUES

Electric Interruptible Service

On June 17, 2004, LG&E filed a letter, which the Commission will treat as a motion, regarding a potential problem related to proposed changes to its interruptible service tariff. Those changes, as set forth in the unanimous provisions of the Partial Settlement and Stipulation shorten the notice of interruption, increase the maximum number of hours of interruption, and increase the potential frequency of interruptions. LG&E believes that due to these changes some customers may, for operational reasons, want to switch from interruptible service to firm service. Consequently, LG&E is requesting authority to waive the 6-month notice required for a customer to terminate service under this tariff. This authority will permit LG&E to give the six customers

[147] Case No. 2001-00323, Joint Application of Louisville Gas and Electric Company, Metro Human Needs Alliance, People Organized and Working for Energy Reform, Kentucky Association for Community Action, and Jefferson County Government for the Establishment of a Home Energy Assistance Program, final Order dated December 27, 2001; rehearing Order dated January 29, 2002.

currently on this tariff the option to terminate service immediately, rather than being required to continue taking interruptible service for an additional 6 months.

Based on the significance of the changes in the terms and conditions of interruptible service, the Commission finds that LG&E's request to waive the 6-month notice of termination is reasonable. However, it is impractical for LG&E and an interruptible customer to switch rate schedules either immediately or on the effective date of the revised interruptible service tariff. Therefore, LG&E will be authorized to contact interruptible customers immediately upon issuance of this Order and inform them that they have a one-time opportunity to waive the 6-month notice of termination. Those customers will have until July 31, 2004 to notify LG&E if they elect to terminate interruptible service and switch to a firm service tariff.

Midwest Independent Transmission System Operator, Inc. ("MISO") Exit Fee

LG&E is currently a member of the Midwest Independent Transmission System Operator, Inc. ("MISO"), a regional transmission organization. In Case No. 2003-00266,[148] LG&E has requested authority to exit MISO and recover any exit fee from ratepayers. In this rate case, LG&E and the AG have addressed how the exit fee should be accounted for and what rate-making treatment is appropriate in the event the Commission authorizes LG&E to exit MISO. However, since the Commission has not yet decided whether LG&E should exit MISO, issues related to the accounting and rate-making treatment for an exit fee are premature. These issues will be addressed, if necessary, in Case No. 2003-00266.

[148] Case No. 2003-00266, Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

The "Global Settlement"

On October 31, 2001, LG&E, KU, the AG, and KIUC filed a unanimous settlement agreement that was intended to operate as a full and complete resolution of five cases then pending before the Commission.[149] This settlement agreement, referred to as the "Global Settlement," was approved by Commission Order on December 3, 2001. Several of the provisions of the Global Settlement directly affected adjustments proposed by LG&E in this rate case.

Article 1.0 of the Global Settlement provided that LG&E would perform a new depreciation study no later than calendar year 2004 based upon utility plant in service as of December 31, 2003 and when completed the new study would be filed with the Commission. LG&E did perform a new depreciation study which was filed in this case, but it was based on utility plant in service as of December 31, 2002. LG&E contended that this depreciation study was in compliance with the Global Settlement, arguing that, "the defining limit on the previous commitment was the timing of another study (e.g., 'no later than calendar year 2004')," and that it "did not believe the plant-in-service date was intended to be the defining limit …."[150]

[149] The five cases were Case No. 2001-00054, The Annual Earnings Sharing Mechanism Filing of Louisville Gas and Electric Company; Case No. 2001-00055, The Annual Earnings Sharing Mechanism Filing of Kentucky Utilities Company; Case No. 2001-00140, Application of Kentucky Utilities Company for an Order Approving Revised Depreciation Rates; Case No. 2001-00141, Application of Louisville Gas and Electric Company for an Order Approving Revised Depreciation Rates; and Case No. 2001-00169, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving Proposed Deferred Debits and Declaring the Amortization of the Deferred Debits to be Included in Earnings Sharing Mechanism Calculations.

[150] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 21.

Article 2.0 of the Global Settlement addressed issues related to LG&E's VDT workforce reduction and authorized LG&E to establish a regulatory asset which would include the expenses incurred to achieve the savings associated with the VDT workforce reduction. At the time the Global Settlement was approved, the regulatory asset was to be established based on estimated expenses. Later, the regulatory asset was to be adjusted to reflect actual VDT-related expenses as of December 31, 2001. However, for rate-making purposes, the actual expenses could not exceed the preliminary estimated expenses. During this case, LG&E disclosed that it had increased the balance in the VDT regulatory asset by $680,800 for expenses incurred after December 31, 2001.[151] LG&E contended that recording these additional expenses as part of the regulatory asset was consistent with the recording of the estimated expenses permitted when the Commission approved the Global Settlement. LG&E argued that it was in compliance with the terms of the Global Settlement because these additional expenses did not cause the regulatory asset balance to exceed the settlement amount of the expenses. LG&E stated that while it did record the additional expenses as part of the regulatory asset, it did not make an adjustment to the net savings returned to ratepayers through the VDT surcredit.[152] LG&E did include adjustments in this rate case to revise the VDT amortization expense to correspond with the regulatory asset as it was recorded on December 31, 2001.

[151] LG&E recorded these additional expenses in the regulatory asset account between December 2002 and July 2003. See Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 15(b)(1).

[152] Response to the Commission Staff's Fourth Data Request dated April 14, 2004, Item 3.

The Commission is concerned by LG&E's interpretation of provisions of the Global Settlement as reflected in this rate case. Contrary to LG&E's interpretation of the Global Settlement provision concerning the timing of its next depreciation study, it is clear that the calendar year 2004 deadline for filing and the utilization of utility plant in service as of December 31, 2003 are both controlling dates. Concerning the VDT regulatory asset, the Global Settlement did not contain any provisions that authorized LG&E to continue to increase the balance of the regulatory asset established on December 31, 2001. The fact that the additional expenses did not exceed the originally estimated expenses does not justify LG&E's accounting.

The Commission notes that, in Case No. 2002-00071, [153] LG&E previously misinterpreted provisions of the Global Settlement. In that case the Commission found that the Global Settlement did not authorize LG&E to adjust its monthly capitalization to retroactively reflect the VDT workforce reduction, and LG&E was required to recalculate its ESM annual filing for calendar year 2001.

The Commission will not require LG&E to submit a new depreciation study in compliance with the dates established in the Global Settlement since we are accepting LG&E's proposal to prepare a new depreciation study no later than June 30, 2007. In addition, we will not require LG&E to remove the post-2001 additions to its VDT regulatory asset since the amortization expenses that were included for rate-making purposes were consistent with the provisions of the Global Settlement and the

[153] Case No. 2001-00071, Louisville Gas and Electric Company's Annual Earnings Sharing Mechanism Filing for Calendar Year 2001.

regulatory asset is not included in rate base. Consequently, ratepayers have not been harmed by LG&E's actions.

The Commission is concerned, however, that on three separate occasions LG&E has incorrectly interpreted and deviated from significant provisions of the Global Settlement. The unanimous provisions of the Partial Settlement and Stipulation approved herein are significantly more encompassing and complex than the provisions contained in the Global Settlement. The Commission cautions LG&E that, absent prior Commission approval, there should be no deviations from either the unanimous provisions of that document or LG&E's timetable for filing a new depreciation study.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by LG&E in its application are denied.

2. The ESM Settlement, attached hereto as Appendix B, is approved in its entirety and LG&E's ESM is terminated except for continued collections for 2003 operations.

3. The unanimous provisions in the Partial Settlement and Stipulation, attached hereto as Appendix C, are approved in their entirety.

4. The rates and charges in LG&E Electric Exhibit 1 and LG&E Gas Exhibit 1, set forth in Appendix A hereto, are the fair, just, and reasonable rates for LG&E to charge for electric and gas service, and these rates are approved for service rendered on and after July 1, 2004.

5. LG&E shall, within 20 days of the date of this Order, file its revised tariff sheets setting out the rates and tariff changes approved herein.

6. Within one year from the date of this Order, LG&E shall file with the Commission a plan developed and implemented that eliminates the underfunding of its pension and post-retirement plans. LG&E shall also file progress reports on its progress to eliminate the underfunding of the pension and post-retirement plans as described within this Order.

7. LG&E shall monitor its summer electric demand, beginning July 1, 2004 and continuing through September 30, 2006, to ascertain the extent of any impacts from the rate design changes approved herein. LG&E shall prepare an analysis and report as described in the findings above.

8. LG&E shall submit for Commission approval the programmatic details associated with its HEA program no later than August 1, 2004.

9. LG&E shall not bill its residential electric and gas customers 10 cents per meter per month for the HEA until authorized to do so upon Commission approval of the HEA programmatic details.

10. LG&E's request for a one-time waiver through July 31, 2004 of the 6-month customer notice to terminate interruptible electric service is granted.

Done at Frankfort, Kentucky, this 30th day of June, 2004.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

The following rates and charges are prescribed for the customers in the area served by Louisville Gas & Electric Company, consistent with LG&E Electric Exhibit 1 and LG&E Gas Exhibit 1. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE RATES

SCHEDULE RS
RESIDENTIAL RATE

Customer Charge per Month:	$ 5.00
Energy Charge per kWh:	$ .05887

SCHEDULE RPM
PREPAID METERING PILOT PROGRAM

Facilities Charge per Month:	$ 2.05
Customer Charge per Month:	$ 5.00
Energy Charge per kWh:	$ .05887

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT SERVICE

Customer Charge per Month:	$ 5.00
Energy Charge per kWh:	$ .05887

SCHEDULE GS
GENERAL SERVICE RATE

Customer Charge per Month – Single Phase:	$ 10.00
Customer Charge per Month – Three Phase:	$ 15.00
Energy Charge per kWh:	
Summer Season	$ .07086
Winter Season	$ .06313

SCHEDULE LC
LARGE COMMERCIAL RATE – PRIMARY VOLTAGE

Customer Charge per Month:	$ 65.00
Demand Charge per kW:	
Summer Season	$ 12.32
Winter Season	$ 9.52
Energy Charge per kWh:	$ .02349

SCHEDULE LC
LARGE COMMERCIAL RATE – SECONDARY VOLTAGE

Customer Charge per Month:	$ 65.00
Demand Charge per kW:	
Summer Season	$ 14.20
Winter Season	$ 11.14
Energy Charge per kWh:	$ .02349

SCHEDULE LC-TOD
LARGE COMMERCIAL TIME-OF-DAY PRIMARY VOLTAGE

Customer Charge per Month:	$ 90.00
Basic Demand Charge per kW:	$ 2.17
Peak Demand Charge per kW:	
Summer Season	$ 10.15
Winter Season	$ 7.35
Energy Charge per kWh:	$ .02349

SCHEDULE LC-TOD
LARGE COMMERCIAL TIME-OF-DAY SECONDARY VOLTAGE

Customer Charge per Month:	$ 90.00
Basic Demand Charge per kW:	$ 3.22
Peak Demand Charge per kW:	
Summer Season	$ 10.98
Winter Season	$ 7.92
Energy Charge per kWh:	$ .02349

SCHEDULE LP
INDUSTRIAL POWER RATE TRANSMISSION VOLTAGE

Customer Charge per Month:	$ 90.00
Demand Charge per kW:	
Summer Season	$ 11.35
Winter Season	$ 8.76
Energy Charge per kWh:	$ .02000

SCHEDULE LP
INDUSTRIAL POWER RATE PRIMARY VOLTAGE

Customer Charge per Month:	$ 90.00
Demand Charge per kW:	
Summer Season	$ 12.55
Winter Season	$ 9.96
Energy Charge per kWh:	$ .02000

SCHEDULE LP
INDUSTRIAL POWER RATE SECONDARY VOLTAGE

Customer Charge per Month:	$ 90.00
Demand Charge per kW:	
Summer Season	$ 14.35
Winter Season	$ 11.76
Energy Charge per kWh:	$ .02000

SCHEDULE LP-TOD
INDUSTRIAL POWER TIME-OF-DAY TRANSMISSION VOLTAGE

Customer Charge per Month:	$ 120.00
Demand Charge per kW:	$ 2.33
Peak Demand Charge per kW:	
Summer Season	$ 9.02
Winter Season	$ 6.43
Energy Charge per kWh:	$ .02000

SCHEDULE LP-TOD
INDUSTRIAL POWER TIME-OF-DAY PRIMARY VOLTAGE

Customer Charge per Month:	$ 120.00
Demand Charge per kW:	$ 3.52
Peak Demand Charge per kW:	
Summer Season	$ 9.03
Winter Season	$ 6.44
Energy Charge per kWh:	$ .02000

SCHEDULE LP-TOD
INDUSTRIAL POWER TIME-OF-DAY SECONDARY VOLTAGE

Customer Charge per Month:	$ 120.00
Demand Charge per kW:	$ 4.62
Peak Demand Charge per kW:	
Summer Season	$ 9.73
Winter Season	$ 7.14
Energy Charge per kWh:	$ .02000

SCHEDULE LI-TOD
LARGE INDUSTRIAL TIME-OF-DAY RATE TRANSMISSION VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kVA:	$ 2.33
Peak Demand Charge per kVA:	
Summer Season	$ 9.02
Winter Season	$ 6.43
Energy Charge per kVA:	$ .02000

SCHEDULE LI-TOD
LARGE INDUSTRIAL TIME-OF-DAY RATE PRIMARY VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kVA:	$ 3.52
Peak Demand Charge per kVA:	
Summer Season	$ 9.03
Winter Season	$ 6.44
Energy Charge per kWh:	$ .02000

SCHEDULE LI-TOD
LARGE INDUSTRIAL TIME-OF-DAY RATE SECONDARY VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kVA:	$ 4.62
Peak Demand Charge per kVA:	
Summer Season	$ 9.73
Winter Season	$ 7.14
Energy Charge per kWh:	$ .02000

RATE CSR 1
CURTAILABLE SERVICE RIDER 1

	Transmission	Primary
Demand Credit per kW per Month	$ 3.10	$ 3.20
Non-compliance Charge Per kW Per Month	$ 16.00	$ 16.00

RATE CSR 2
CURTAILABLE SERVICE RIDER 2

	Transmission	Primary
Demand Credit per kW per Month	$ 3.98	$ 4.05
Non-compliance Charge Per kW Per Month	$ 16.00	$ 16.00

RATE CSR 3
CURTAILABLE SERVICE RIDER 3

	Transmission	Primary
Demand Credit per kW per Month	$ 3.10	$ 3.20
Non-compliance Charge Per kW Per Month	$ 16.00	$ 16.00

SCHEDULE SLE
STREET LIGHTING ENERGY RATE

Energy Charge per kWh:	$ .04059

SCHEDULE TLE
TRAFFIC LIGHTING ENERGY RATE

Customer Charge per Month:	$ 2.80
Energy Charge per kWh	$ .05114

SCHEDULE PSL
PUBLIC STREET LIGHTING SERVICE

	Rate per Month per Unit	
Overhead Service	To 1/1/1991	After 12/31/1990
Mercury Vapor		
100 Watt	$ 6.52	$ NA
175 Watt	$ 7.59	$ 9.45
250 Watt	$ 8.61	$ 10.57
400 Watt	$ 10.25	$ 12.65
400 Watt (Metal Pole)	$ 14.90	$ NA
1,000 Watt	$ 18.92	$ 22.78
High Pressure Sodium		
100 Watt	$ 7.80	$ 7.80
150 Watt	$ 9.32	$ 9.32
250 Watt	$ 11.12	$ 11.12
400 Watt	$ 11.49	$ 11.49
1,000 Watt	$ NA	$ 26.13
Underground Service		
Mercury Vapor		
100 Watt-Top Mounted	$ 10.68	$ 13.19
175 Watt-Top Mounted	$ 11.65	$ 14.28
175 Watt	$ 15.84	$ 22.56
250 Watt	$ 16.90	$ 23.68
400 Watt	$ 19.83	$ 25.76
400 Watt (State of Ky. pole)	$ 19.83	$ 25.76
High Pressure Sodium Vapor		
70 Watt-Top Mounted	$ NA	$ 11.31
100 Watt-Top Mounted	$ 11.73	$ 11.73
150 Watt-Top Mounted	NA	$ 17.35
150 Watt	$ 20.33	$ 20.33
250 Watt	$ 21.51	$ 21.51
250 Watt on State of Ky. Pole	$ 21.51	$ 21.51
400 Watt	$ 22.97	$ 22.97
400 Watt on State of Ky. Pole	$ 22.97	$ 22.97
1000 Watt	$ NA	$ 53.45
Decorative Lighting Service		Rate per month

Fixtures	
Acorn with Decorative Basket	
70 Watt High Pressure Sodium	$ 15.62
100 Watt High Pressure Sodium	$ 16.25
8-Sided Coach	
70 Watt High Pressure Sodium	$ 15.83
100 Watt High Pressure Sodium	$ 16.44
Poles	
10 ft. Smooth	$ 9.36
10 ft. Fluted	$ 11.17
Bases	
Old Town/Manchester	$ 3.00
Chesapeake/Franklin	$ 3.22
Jefferson/Winchester	$ 3.25
Norfolk/Essex	$ 3.42

SCHEDULE OL
OUTDOOR LIGHTING SERVICE

	Rate per Month per Unit	
Overhead Service	To 1/1/1991	After12/31/1990
Mercury Vapor		
100 Watt	$ 7.27	$ NA
175 Watt	$ 8.18	$ 9.64
250 Watt	$ 9.25	$ 10.77
400 Watt	$ 11.19	$ 12.85
1000 Watt	$ 20.30	$ 23.05
High Pressure Sodium		
100 Watt	$ 8.07	$ 8.07
150 Watt	$ 10.32	$ 10.32
250 Watt	$ 12.14	$ 12.14
400 Watt	$ 12.75	$ 12.75
1000 Watt	$ NA	$ 30.20
Additional Pole Charge	$ 1.78	$ 1.78
Underground Service		
Mercury Vapor		
100 Watt Top Mounted	$ 12.70	$ 13.48
175 Watt Top Mounted	$ 13.48	$ 14.49
High Pressure Sodium		
70 Watt Top Mounted	$ 11.31	$ 11.31
100 Watt Top Mounted	$ 14.94	$ 14.94
150 Watt Top Mounted	$ NA	$ 18.11
150 Watt	$ 20.35	$ 20.35

250 Watt	$ 23.29	$ 23.29
400 Watt	$ 25.57	$ 25.57
1000 Watt	$ NA	$ 57.51

Decorative Lighting Service	Rate per month
Fixtures	
Acorn with Decorative Basket	
70 Watt High Pressure Sodium	$ 16.03
100 Watt High Pressure Sodium	$ 16.77
8-Sided Coach	
70 Watt High Pressure Sodium	$ 16.21
100 Watt High Pressure Sodium	$ 16.95
Poles	
10 ft. Smooth	$ 9.36
10 ft. Fluted	$ 11.17
Bases	
Old Town/Manchester	$ 3.00
Chesapeake/Franklin	$ 3.22
Jefferson/Winchester	$ 3.25
Norfolk/Essex	$ 3.42

SCHEDULE LS
LIGHTING SERVICE

Underground Service

	Lumen Output (approximate)	Monthly Rate Per Light
High Pressure Sodium		
4 Sided Colonial	6,300	$ 15.54
4 Sided Colonial	9,500	$ 16.05
4 Sided Colonial	16,000	$ 17.01
Acorn	6,300	$ 15.88
Acorn	9,500	$ 17.85
Acorn (Bronze Pole)	9,500	$ 18.74
Acorn	16,000	$ 18.80
Acorn (Bronze Pole)	16,000	$ 19.62
Contemporary	16,000	$ 24.18
Contemporary	28,500	$ 26.61
Contemporary	50,000	$ 29.95
Cobra Head	16,000	$ 21.10
Cobra Head	28,500	$ 22.80
Cobra Head	50,000	$ 26.18

* London (10' Smooth Pole)	6,300	$ 27.18
* London (10' Fluted Pole)	6,300	$ 28.89
* London (10' Smooth Pole)	9,500	$ 27.84
* London (10' Fluted Pole)	9,500	$ 29.56
* Victorian (10' Smooth Pole)	6,300	$ 26.34
* Victorian (10' Fluted Pole)	6,300	$ 28.06
* Victorian (10' Smooth Pole)	9,500	$ 26.91
* Victorian (10' Fluted Pole)	9,500	$ 28.62
* Bases Available:		
Old Town / Manchester		$ 2.53
Chesapeake / Franklin		$ 2.53
Jefferson / Westchester		$ 2.53
Norfolk / Essex		$ 2.69
Mercury Vapor		
4 Sided Colonial	4,000	$ 15.60
4 Sided Colonial	8,000	$ 17.05
Cobra Head	8,000	$ 21.09
Cobra Head	13,000	$ 22.43
Cobra Head	25,000	$ 25.26
Overhead Service		
High Pressure Sodium		
Cobra Head	16,000	$ 9.16
Cobra Head	28,500	$ 10.86
Cobra Head	50,000	$ 14.24
Directional Flood	16,000	$ 10.60
Directional Flood	50,000	$ 15.11
Open Bottom	9,500	$ 8.01
Mercury Vapor		
Cobra Head	8,000	$ 9.15
Cobra Head	13,000	$ 10.49
Cobra Head	25,000	$ 13.32
Directional Flood	25,000	$ 14.69
Open Bottom	8,000	$ 8.89
Additional Pole Charge		$ 9.79

STANDARD RIDER FOR
SUPPLEMENTAL OR STANDBY SERVICE

The monthly bill shall in no case be less than an amount calculated at the rate of $6.25 per kW applied to the contract demand.

STANDARD RIDER FOR
REDUNDANT CAPACITY CHARGE

Capacity Reservation Charge Per kW Per Month:

Secondary Distribution	$ 1.43
Primary Distribution	$ 1.06

EXPERIMENTAL LOAD
REDUCTION INCENTIVE RIDER

Rate:	Up to $ 0.30 per kWh

RATE STOD
EXPERIMENTAL SMALL TIME-OF-DAY SERVICE

Customer Charge per Month:		$ 80.00
Energy Charge per kWh:		
On Peak		$ .02936
Off Peak		$ .01370
Demand Charge per kW:	Secondary	Primary
Summer Season	$ 14.20	$ 12.32
Winter Season	$ 11.14	$ 9.52

STANDARD RIDER FOR EXCESS FACILITIES

Charge for Distribution Facilities

Carrying Cost:	0.94%
Operating Expenses:	0.68%

RETURNED CHECK CHARGE

Rate:	$ 7.50

METER TEST CHARGE

Rate:	$ 31.40

DISCONNECT AND RECONNECT SERVICE CHARGE

Rate:	$ 20.00

SPECIAL CONTRACT
FORT KNOX

Demand Charge Per kW Per Month:	
Summer Season	$ 11.94
Winter Season	$ 9.75
Energy Charge Per kWh:	$ 0.02000

SPECIAL CONTRACT
DUPONT

Demand Charge Per kW Per Month:	$ 11.15
Energy Charge Per kWh:	$ 0.02000

SPECIAL CONTRACT
UNITED PARCEL SERVICE

Customer Charge Per Month:	$ 120.00
Demand Charge Per kW Per Month:	
Basic Demand Charge	$ 6.30
Seasonal Demand Charge	
Summer Season	$ 7.65
Winter Season	$ 3.27
Energy Charge Per kWh:	$ 0.02000

SPECIAL CONTRACT
GENERAL ELECTRIC

Customer Charge Per Month:	$ 74.29
Demand Charge Per kW Per Month:	
Basic Demand Charge	$ 4.62
Seasonal Demand Charge	
Summer Season	$ 7.65
Winter Season	$ 3.27
Energy Charge Per kWh:	$ .02000

SPECIAL CONTRACT
LOUISVILLE WATER COMPANY

Demand Charge Per kW Per Month:	$ 8.33
Energy Charge Per kWh:	$ .01988

GAS SERVICE RATES

RATE RGS
RESIDENTIAL GAS SERVICE

Customer Charge Per Month:	$ 8.50
Distribution Charge Per Ccf:	$ .15470

RATE VFD
VOLUNTEER FIRE DEPARTMENT SERVICE

Customer Charge Per Month:	$ 8.50
Distribution Charge Per Ccf:	$ .15470

RATE CGS
FIRM COMMERCIAL GAS SERVICE

Customer Charge Per Month:	
Meters < 5000 cf/hr	$ 16.50
Meters >= 5000 cf/hr	$ 117.00
Distribution Charge	
On Peak Ccf:	$ .14968
Off Peak Ccf:	$ .09968

Transportation Service/Standby Rider to Rate CGS

Administrative Charge Per Month:	$ 90.00
Distribution Charge	
On Peak Ccf:	$ .14968
Off Peak Ccf:	$ .09968

RATE IGS
FIRM INDUSTRIAL GAS SERVICE

Customer Charge Per Month:	
Meters < 5000 cf/hr	$ 16.50
Meters >= 5000 cf/hr	$ 117.00
Distribution Charge	
On Peak Ccf:	$ .14968
Off Peak Ccf:	$ .09968

Transportation Service/Standby Rider to Rate IGS

Administrative Charge Per Month:	$ 90.00
Distribution Charge	
On Peak Ccf:	$ .14968
Off Peak Ccf:	$ .09968

RATE AAGS
AS AVAILABLE GAS SERVICE

Current Rate G-6 and G-6/TS Customers

Customer Charge Per Month	$ 150.00
Distribution Charge Per Ccf:	$ .05252

Current Rate G-6 Customers

Customer Charge Per Month:	$ 150.00
Distribution Charge Per Ccf:	$ .05252

RATE FT
FIRM TRANSPORTATION SERVICE
(NON-STANDBY)

Administrative Charge Per Month:	$ 90.00
Distribution Charge Per Ccf:	$ .4300
Utilization Charge for Daily Imbalances Per Ccf	$ .3807

RATE PS-FT
POOLING SERVICE RIDER TO RATE FT

PS-FT Pool Administration Charge: $75 per customer in FT Pool per month.

RATE RBS
RESERVE BALANCING SERVICE

Applicable to Reserved Balance Volume

Monthly Demand Charge Per Mcf:	$ 5.1700
Monthly Balancing Charge Per Mcf:	$ 3.6500
Total	$ 8.8200

STANDARD RIDER FOR EXCESS FACILITIES

Charge for Distribution Facilities

Carrying Cost:	0.94%
Operating Expenses:	0.68%

RETURNED CHECK CHARGE

Rate: $ 7.50

METER TEST CHARGE

Rate: $ 69.00

DISCONNECT AND RECONNECT SERVICE CHARGE

Rate: $ 20.00

INSPECTION CHARGE

Rate: $ 135.00

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

ESM SETTLEMENT AGREEMENT
Dated May 12, 2004

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 12th day of May 2004, by and between Louisville Gas and Electric Company ("LG&E"); Kentucky Utilities Company ("KU") (LG&E and KU are hereafter collectively referenced as "the Utilities"); Commonwealth of Kentucky, ex. rel. Gregory Stumbo, Attorney General, by and through the Office of Rate Intervention ("AG"); Kentucky Industrial Utility Customers, Inc. ("KIUC") and the interests of its participating members as represented by and **through** the KIUC; Commonwealth of Kentucky, Environmental and Public Protection Cabinet, Division of Energy ("KDOE"); the United States Department of Defense ("DOD); The Kroger Company ("Kroger"); Kentucky Association for Community Action, Inc. ("KACA"); 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 ("LFUCG); and North American Stainless, L.P. ("NAS") in the proceedings involving LG&E and KU which are the subject of this Settlement Agreement, ***as*** set forth below.

W I T N E S S E T R :

WHEREAS, LG&E filed on December 29, 2003 with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Rates, ***In** Re the Matter of: **An** Adjustment of the Gas and Electric Rates. Terms and Conditions of Louisville* Gar *and Electric Comuanv*, and the Commission has established Case No. 2003-00433 to review LG&E's base rate application;

WHEREAS, KU filed on December 29, 2003 with the Commission its Application for Authority to Adjust Rates, *In Re the Matter of: An Adjustment **of** the Electric Rates, Terms and Conditions of Kentucky Utilities Comuanv*, and the Commission has established Case No. 2003-00434 to review KU's base rate application;

WHEREAS, the AG, KIUC, KDOE and Kroger have been granted intervention by the Commission in both of the forgoing proceedings; MHNA, POWER, DOD and KACA have been granted intervention by the Commission in Case No. 2003-00433 only; and LFUCG, NAS and CAC have been granted intervention by the Commission in Case No. 2003-00434 only;

WHEREAS, on March 31, 2004, the Commission granted consolidation of Case No. 2003-00433 with the case captioned _In Re the Matter of An Investigation Pursuant to KRS 278.260 of the Earnings Sharing Mechanism Tariff of Louisville Gas and Electric Company_, Case No. 2003-00335;

WHEREAS, on March 31, 2004, the Commission granted consolidation of Case No. 2003-00434 with the case entitled _In Re the Matter of: An Investigation Pursuant to KRS 278.260 of the Earnings Sharing Mechanism Tariff of Kentucky Utilities Company_, Case No. 2003-00334;

WHEREAS, the AG and KIUC have been granted intervention by the Commission in both Case Nos. 2003-00334 and 2003-00335; and LFUCG has been granted intervention by the Commission in Case No. 2003-00334 only;

WHEREAS, LG&E's current Earnings Sharing Mechanism tariff was effective on January 2, 2003 pursuant to the Commission's Orders of December 20, 2002 and January 14, 2003 in Case No 2002-00473 (LG&E); and KU's current ESM tariff was effective on January 2, 2003 pursuant to the Commission's Orders of December 20,2002 and January 14,2003 in Case No. 2002-00472 (collectively the "ESM tariffs");

WHEREAS, on March 1, 2004 LG&E filed its Annual Earnings Sharing Mechanism Filing for Calendar Year 2003 in Case No. 2004-00069;

WHEREAS, on March 1,2004 KU filed its Annual Earnings Sharing Mechanism Filing for Calendar Year 2003 in Case No. 2004-00070;

WHEREAS, a prehearing conference, attended in person or by teleconference by representatives of the AG, KIUC, KDOE, DOD, Kroger, KACA, CAC, MHNA, POWER, LFUCG, NAS, the Commission Staff and the Utilities, took place on April 28, 2004 at the offices of the Commission during which a number of procedural and substantive issues were discussed, including potential settlement of certain issues pending before the Commission in Case Nos. 2003-00433 and 2003-00434, Case Nos. 2003-00334 and 2003-00335 (the "ESM renewal proceedings"), and Case Nos. 2004-00069 and 2004-00070 (the "2003 ESM proceedings"); and

WHEREAS, the signatories hereto desire to settle certain issues pending before the Commission in the rate proceedings, the ESM renewal proceedings and the 2003 ESM proceedings.

NOW, THEREFORE, for and in consideration of the premises and conditions set forth herein, the parties hereby agree as follows:

ARTICLE I. **<u>Earnings Sharing Mechanism ("ESM") Recoverv and Discontinuation</u>**

SECTION 1.1 Effective July 1,2004, the Earnings Sharing Mechanism, except as set forth in Sections 1.2 through 1.4 below, shall be discontinued,

SECTION 1.2 LG&E has filed with the Commission, in Case No. 2004-0069, the results for the 2003 ESM Reporting Period and the corresponding ESM billing factor pursuant to its ESM tariff. Beginning April 1, 2004, LG&E began billing its 2003 ESM factor in customer bills. The parties recommend the Commission issue an order in Case No.

2004-0069 approving the 2003 ESM factor as filed and authorizing LG&E to continue billing its ESM factor through March 31, 2005 and collect and retain all the revenues derived from the billing of 2003 ESM factor. Specifically, for the period of April 1, 2004 through April 30, 2004, LG&E should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.282%. And, specifically, for the period of May 1, 2004 through March 31, 2005, LG&E should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.360%.

SECTION 1.3 KU has filed with the Commission, in Case No. 2004-0070, the results for the 2003 ESM Reporting Period and the corresponding ESM billing factor pursuant to its ESM tariff. Beginning April 1, 2004, KU began billing its 2003 ESM factor in customer bills. The parties recommend the Commission issue an order in Case No. 2004-0070 approving the 2003 ESM factor as filed and authorizing KU to continue billing its ESM factor through March 31, 2005 and collect and retain all the revenues derived from the billing of 2003 ESM factor. Specifically, for the period of April 1, 2004 through April 30, 2004, KU should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.367%. And, specifically, for the period of May 1, 2004 through March 31, 2005, KU should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.330%.

SECTION I.4 No later than May 2005, the Utilities shall perform a final balancing adjustment to reconcile any over- or under-collection of the ESM revenues for the current ESM billing period, April 2004 through March 2005.

SECTION 1.5 The Utilities agree to waive their rights to make any billing or seek any collection under their respective ESM tariffs for the six-month period ending June 30, 2004, excluding the operation of the ESM mechanism as provided in Sections 1.2 through 1.4 above.

ARTICLE II. Approval of Settlement Agreement

SECTION 2.1 Following the execution of this Settlement Agreement, the signatories shall cause the Settlement Agreement to be filed with the Commission with a request to the Commission for consideration and approval of this Settlement Agreement by May ____, 2004.

SECTION 2.2 The signatories to this Settlement Agreement shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be accepted and approved.

SECTION 2.3 If the Commission issues a final order which accepts and approves this Settlement Agreement in its entirety, then the parties hereto hereby waive any and all claims or demands, asserted or unasserted, directly arising out of or in connection with the application or operation of the Utilities' respective ESMs in Case Nos. 2004-0069, 2004-070, 2003-00334 and 2003-00335, and all such claims or demands shall be deemed settled under or compromised, released and discharged by this Settlement Agreement.

SECTION 2.4 If the Commission does not accept and approve this Settlement Agreement in its entirety, then: (a) this Settlement Agreement shall be void and withdrawn by the parties hereto from further consideration by the Commission and none of the parties shall be bound by any of the provisions herein; and (b) neither the teims of this Settlement Agreement nor any matters raised during the settlement negotiations shall be binding on any of the signatories to this Settlement Agreement or be construed against any of the signatories.

SECTION 2.5 Should the Settlement Agreement be voided or vacated for any reason after the Commission has approved the Settlement. Agreement and thereafter any implementation of the terms of the Settlement Agreement has been made, then the parties shall be returned to the *status quo* existing at the time immediately prior to the execution of this agreement.

ARTICLE III. Additional Provisions

SECTION 3.1 This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

SECTION 3.2 This Settlement Agreement shall inure to the benefit of and be binding upon the parties hereto, their heirs, successors and assigns.

SECTION 3.3 This Settlement Agreement constitutes the complete agreement and understanding among the parties hereto, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

SECTION 3.4 For the purpose of this Settlement Agreement only, the terms are based upon the independent analysis of the parties to reflect a just and reasonable resolution of the issues herein and are the product of compromise and negotiation. Notwithstanding anything contained in the Settlement Agreement, the parties recognize and agree that the effects, if any, of any future events upon the operating income of LG&E or KU are unknown and this Settlement Agreement shall be implemented as written.

SECTION 3.5 Neither the Settlement Agreement nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Settlement Agreement. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

SECTION 3.6 The provisions of this Settlement Agreement shall not bar a party from seeking, or the Commission from reinstating, an ESM at some future time, in order to accomplish reasonable and valid regulatory objectives.

SECTION 3.7 Making this Settlement Agreement shall not be deemed in any respect to constitute an admission by any party hereto that any computation, formula, allegation, assertion or contention made by any other **party** in these proceedings is true or valid.

SECTION 3.8 The signatories hereto warrant that they have informed, advised, and consulted with the respective parties hereto in regard to the contents and significance of this agreement and based upon the foregoing are authorized to execute this Settlement Agreement on behalf of the parties hereto.

SECTION 3.9 This Settlement Agreement is subject to the acceptance of and approval by the Public Service Commission.

SECTION 3.10 This Settlement Agreement is a product of negotiation among all parties hereto, and no provision of this Settlement Agreement shall be strictly construed in favor of or against any party.

SECTION 3.11 This Settlement Agreement may be executed in multiple counterparts.

IN WITNESS WHEREOF, *the* parties hereto have hereunto affixed their signatures.

Louisville Gas and Electric Company
and Kentucky Utilities Company

HAVE **READ AND** AGREED:

By: ______________________
Kendrick R. Riggs, Counsel

-and-

By: ______________________
Dorothy E. O'Brien, Counsel

Commonwealth of Kentucky, **ex.** rel. Gregory Stumbo, Attorney General, by and through the Office of Rate Intervention

HAVE READ AND AGREED:

By:________________________________
Elizabeth E. Blackford, Counsel

Kentucky Industrial Utility Customers, Inc.

HAVE READ AND AGREED:

By: ______________________________
David F. Boehm, Counsel
Michael L. Kurtz, Counsel

Commonwealth of Kentucky,
Environmental **and** Public Protection Cabinet,
Division of Energy

HAVE READ AND AGREED:

By: ______________________________
Iris Skidmore, Counsel

United States Department of Defense

HAVE SEEN AND AGREED:

By: Peter A. Nyers,
for: David A. McCormick, Counsel

The Kroger Company

HAVE READ AND AGREED:

By: ______________________________
David C. Brown, Counsel

Kentucky Association for Community Action, Inc.

HAVE READ **AND** AGREED:

By: ______________________
Joe F. Childers, Counsel

Community Action Council for
Lexington-Fayette, Bourbon, Harrison
and Nicholas Counties, Inc.

HAVE READ AND AGREED:

By: ______________________
Joe F. Childers, Counsel

Metro Human Needs Alliance

HAVE READ AND AGREED:

By: Lisa Kilkelly

Lisa Kilkelly, Counsel

People Organized and Working for Energy Reform

HAVE READ AND AGREED:

Ey: Lisa Kilkelly

Lisa Kilkelly, Counsel

Lexington-Fayette Urban County Government

HAVE READ AND AGREED:

By: ______________________
David J. Barberie, Counsel

North American Stainless, L.P.

HAVE READ AND AGREED:

By: ____________________
Richard S. Taylor, Counsel

By: ____________________
Nathaniel K. Adams, General Counsel

By: ____________________
Kimberly McCann, Counsel

303071.4

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

PARTIAL SETTLEMENT AND STIPULATION
Dated May 12, 2004

PARTIAL SETTLEMENT AGREEMENT, STIPULATION AND RECOMMENDATION

This Partial Settlement Agreement, Stipulation and Recommendation ("Settlement Agreement") is entered into this 12th day of May 2004, by and between Louisville Gas and Electric Company ("LG&E"); Kentucky Utilities Company ("KU") (LG&E and KU are hereafter collectively referenced as "the Utilities"); Commonwealth of Kentucky, ex. rel. Gregory Stumbo, Attorney General, by and through the Office of Rate Intervention ("AG); Kentucky Industrial Utility Customers, Inc. ("KIUC") and the interests of its participating members as represented by and through the KIUC; Commonwealth of Kentucky, Environmental and Public Protection Cabinet, Division of Energy ("KDOE"); the United States Department of Defense ("DOD"); The Kroger Co.("Kroger"); Kentucky Association for Community Action, Inc. ("KACA"); 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 ("LFUCG"); and North American Stainless, L.P. ("NAS") in the proceedings involving LG&E and KU which are the subject of this Settlement Agreement, as set forth below.

W I T N E S S E T H:

WHEREAS, LG&E **filed** on December 29, 2003 with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Rates, ***In Re the Matter of An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*,** and the Commission has established Case No. 2003-00433 to review LG&E's base rate application;

WHEREAS, KU filed on December **29,** 2003 with the Commission its Application for Authority to Adjust Rates, ***In Re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*,** and the Commission has established Case No. 2003-

00434 to review KU's base rate application (Case Nos. 2003-00433 and 2003-00434 are hereafter collectively referenced as the "rate proceedings");

WHEREAS, the AG, KIUC, KDOE, KACA and Kroger have been granted intervention by the Commission in both of the rate proceedings; MHNA, POWER and DOD have been granted intervention by the Commission in Case No. 2003-00433 only; and LFUCG, NAS and CAC have been granted intervention by the Commission in Case No. 2003-00434 only;

WHEREAS, on March 31, 2004, the Commission granted consolidation of Case Nos. 2003-00433 and 2003-00434 with the case captioned *In the Matter of: Tariff Filing of Kentucky Utilities Company and Louisville Gas and Electric Company for Non-Conforming Load Customers*, Case No. 2003-00396 (which case had previously been consolidated with *In the Matter oft North American Stainless v. Kentucky Utilities Company*, Case No. 2003-00376).

WHEREAS, a prehearing conference, attended in person or by teleconference by representatives of the AG, KIUC, KDOE, DOD, Kroger, KACA, CAC, MHNA, POWER, LFUCG, NAS, the Commission Staff and the Utilities, took place on April 28, 2004 at the offices of the Commission during which a number of procedural and substantive issues were discussed, including potential settlement of certain issues pending before the Commission in the rate proceedings;

WHEREAS, on May 4, 2004, the hearing in the rate proceedings began and was adjourned for the purpose of exploring the possibility of settlement of the rate proceedings or stipulation of issues therein, which discussions were attended in person by representatives of the AG, KIUC, KDOE, DOD, Kroger, KACA, CAC, MHNA, POWER, LFIJCG, NAS, the Commission Staff and the Utilities;

WHEREAS, all of the signatories hereto desire to settle all the issues pending before the Commission in the rate proceedings, except for the AG, who is unwilling to settle the issue of the revenue requirements of LG&E's electric operations and KU's operations;

WHEREAS, it is understood by all signatories hereto that this Settlement Agreement is subject to the approval of the Commission, insofar as it constitutes an agreement by all parties to the rate proceedings for settlement, and does not represent agreement on any specific theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms and conditions;

WHEREAS, it is understood by all signatories hereto that, insofar as this Settlement Agreement does not recite the agreement of the **AG** to settle the issue of the revenue requirements of the LG&E electric operations and the KU operations, it is a stipulation among the signatories hereto other than the AG as to the foregoing revenue requirement issues, pursuant to 807 KAR 5:001, Section 4(6);

WHEREAS, the signatories have spent many hours, over several days, in order to reach the stipulations and agreements which form the basis of this Settlement Agreement;

WHEREAS, all of the signatories, who represent diverse interests and divergent viewpoints, agree that this Settlement Agreement, viewed in its entirety, is a fair, just and reasonable resolution of all the issues in the rate proceedings;

WHEREAS, the adoption of this Settlement Agreement will reduce the length of the hearing, simplify the briefing, and eliminate the possibility of, and any need for, rehearing on the issues stipulated and agreed to; and

WHEREAS, it is the position of the parties hereto that this Settlement Agreement is supported by sufficient and adequate data and information, and should be approved by the Commission.

NOW, THEREFORE, for and in consideration of the premises and conditions set forth herein, the parties hereby stipulate and agree as follows:

ARTICLE I. Revenue Requirement.

Section 1.1. The signatories hereto, except the AG, stipulate that the following annual increases in revenues for LG&E electric operations and for KU operations, for purposes of determining the rates of LG&E and KU in the rate proceedings, are fair, just and reasonable for the signatories and for all customers of LG&E (electric) and KU:

Section 1.1.1. LG&E Electric Operations: $43,400,000;

Section 1.1.2. KU Operations: $46,100,000.

The signatories hereto, including the AG, agree that any annual increase in revenues for LG&E electric operations and for KU operations will be effective July 1, 2004.

Section 1.2. The signatories hereto, including the AG, agree that, effective July 1, 2004, the annual increases in revenues for LG&E gas operations of $11,900,000, for purposes of determining the rates of LG&E gas operations in the rate proceedings, are fair, just and reasonable for the signatories and for all gas customers of LG&E.

ARTICLE II. Allocation of Revenue.

Section 2.1. The signatories hereto, including the AG, agree that the allocation of the annual revenue increase for LG&E electric operations, LG&E gas operations and for KU operations, as set forth on the allocation schedule designated Exhibit 1 hereto, in the rate proceedings is fair, just and reasonable for the signatories and for all customers of LG&E and KU. Notwithstanding the foregoing sentence, it is understood that the AG has only agreed that the percentages of the rate classes applicable to each LG&E electric operations rate class and each KU operations rate class on Exhibit 1 hereto are fair, just and reasonable and the AG has made no agreement of any other information relating to such LG&E electric operations or KU operations. All signatories hereto, including the AG, agree that the revenue increase to electric special contract customers set forth on Exhibi! **1** hereto shall be allocated such that each special contract customer shall have the same percentage increase in rates.

Section 2.2. The signatories hereto, except the AG, agree that, effective July 1. 2004, the Utilities shall implement the electric rates set forth on Exhibit 1, attached hereto, which rates the signatories hereto, except the AG, stipulate are fair, just and reasonable and should be approved by the Commission. All signatories hereto, including the AG, agree that. effective July 1, **2004,** the Utilities shall implement the **gas** rates set forth on Exhibit 1, attached hereto, which rates the signatories hereto agree are fair, just and reasonable and should be approved by the Commission.

Section2.3. The signatories hereto, including the AG, agree that the Utilities shall establish **a** pilot time-of-day program for commercial customers with a monthly demand between 250 kW and 2,000 kW. The rates, terms and conditions of said program shall be as set forth in the Stipulation, dated May **4,** 2004, between the Utilities and Kroger and filed in the rate proceedings. A copy of said Stipulation is attached hereto as Exhibit 2 and is incorporated by reference as though fully set forth herein. The forms of tariff designed to implement the Stipulation and the Settlement Agreement are attached hereto as Exhibit 2-A (LG&E) and Exhibit 2-B (KU).

ARTICLE III. Treatment of Certain Specific Issues.

Section 3.1. The signatories hereto, including the AG, agree that, after the date hereof, orders approving cost recovery of LG&E's and KU's environmental projects pursuant to KRS 278.183 shall be based upon an 11.0% return on common equity until directed by order of the Commission that a different rate of return shall be utilized.

Section 3.2. The signatories hereto, including the AG, agree that all of LG&E's gas purification and gas storage loss expenses shall be recovered as part of its Gas Supply Clause mechanism.

Section 3.3. The signatories hereto, except the AG, agree that the depreciation rates of the Utilities shall remain the same as approved in the orders of December 3, 2001, in Case Nos. 2001-140 and 2001-141, until the approval by the Commission of new depreciation rates for the Utilities, for which the

Utilities shall seek approval by filings made in their next general rate cases or June 30, 2007, whichever occurs earlier. The Utilities' depreciation filings shall be based on plant in service as of a date no earlier than one (1) year prior to such filing. From and after the effective date hereof, the Utilities shall maintain their books and records so that net salvage amounts may be identified.

Section 3.4. The signatories hereto, including the AG, agree that all costs associated with KU's 1994 environmental compliance plan (the "1994 Plan") approved in Case No. 93-465 and LG&E's 1995 environmental compliance plan (the "1995 Plan") approved in Case No. 94-332 shall be recovered in the Utilities' base rates, taking into account the Utilities' overall rate of return, and will be removed from the Utilities' monthly environmental surcharge filings, all in accordance with the details of such recovery set forth on Exhibit 3 hereto.

Section 3.5. The signatories hereto, including the AG, agree that, unless the Commission has already modified or terminated the Value Delivery Team ("VDT") surcredits in a subsequent rate case, six (6) months prior to the expiration of the sixty (60) month period in which the VDT surcredits are in operation, the Utilities shall file with the Commission a plan for the future ratemaking treatment of the VDT surcredits, the shareholder savings, the amortization of VDT costs and all other VDT-related issues. The VDT surcredit tariffs shall remain in effect following the expiration of the sixtieth (60th) month until the Commission enters an order on the future ratemaking treatment of all VDT-related issues.

Section *3.6.* The signatories hereto, including the **AG,** agree that LG&E shall establish a real time pricing ("RTP") pilot program for LG&E's electric customers. The tam of the program shall be three **(3)** years. In each year, up to fifty (50) customers under Rate R and up to fifty (50) customers under Rate GS shall qualify for the program. During the second year of the program, LG&E shall propose to the Commission detailed plans, terms and conditions for the inclusion of customers under Rate LP in the program, such inclusion to take place during the second year of the program. Rate LP customers shall be eligible for participation in the program during the second and third years of the program in accordance with the Commission's approval of LG&E's proposal for inclusion of Rate LP customers. The customer-specific costs shall be recovered through a facilities charge incorporated into the applicable customer charges during the first six *(6)* months of the RTP pilot program. **After** six (6) months, the Utilities shall evaluate the level of participation in the pilot program and consider modifymg the treatment of such customer-specific charges to encourage participation in the RTP pilot program. The non customer-specific costs of modifying LG&E's customer billing system to bill customers under the RTP pilot program will be recovered pursuant to the RTP pilot program through a charge per kWh billed to customers taking service under Rates R, GS and LP in the same manner as the Demand-Side

Management ("DSM) Cost Recovery Component of LG&E's DSM Cost Recovery Mechanism. After the end of the three year term, LG&E will evaluate the performance of the RTP pilot program for the following purposes, including, but not limited to: (i) to determine the impact of the pilot program on its affected customers; (ii) to determine the amount of revenue loss from the pilot program, if any; (iii) to evaluate customer acceptance of the real time pricing program and (iv) to evaluate the potential for implementing the RTP program as either a permanent demand-side management program or as a standard rate schedule. LG&E shall file a report with the Commission describing its findings within six months after the first three years of implementation of the RTP pilot program. The RTP pilot program shall remain in effect until the program is modified or terminated by order of the Commission.

Section 3.7. The signatories hereto, including the AG, agree that the notice period for an Operational Flow Order pursuant to LG&E's Rate FT shall be twenty-four **(24)** hours.

Section 3.8. The signatories hereto, including the **AG,** agree that the miscellaneous charges of the Utilities shall be approved as proposed by the Utilities in the rate proceedings, except as follows: (i) the Disconnect-Reconnect Charge for LG&E electric customers, LG&E gas customers and KU electric customers shall be $20.00; and (ii) the KU After-Hours Reconnect Charge shall be withdrawn.

Section 3.9. The signatories hereto, including the AG, agree that the following monthly customer charges shall be implemented: (i) LG&E electric residential customers, $5.00 per month; (ii) LG&E gas residential customers, $8.50 per month; (iii) KU residential customers, $5.00 per month; (iv) LG&E GS electric single phase, $10.00 per month; (v) LG&E GS electric three phase, $15.00 per month; (vi) KU GS primary, $10.00 per month; and (vii) KU GS secondary, $10.00 per month. All other customer charges shall be implemented as proposed by the Utilities in their Applications filed on December 29,2003 in the rate proceedings.

Section 3.10. The signatories hereto, including the **AG,** agree that, for both LG&E and KU, Rate GS shall be available to electric customers with connected loads up to 500 kW.

Section 3.11. The signatories hereto, including the AG, agree that LG&E shall withdraw its Standard Riders for Summer **Air** Conditioning Service for its gas operations, and that customers served thereunder shall take service under otherwise applicable rate schedules.

Section 3.12. The signatories hereto, including the AG, agree that LG&E shall not bill an additional customer charge to Rate GS customers formerly taking service under the Rider for Electric Space Heating Service under Rate GS.

Section 3.13. The signatories hereto, including the AG, agree that LG&E shall eliminate the seasonal rate structure for Rate RS and shall implement a non-seasonally differentiated rate structure for Rate RS. Nothing contained in this Section shall preclude the Utilities from making a future proposal for a seasonal rate structure.

Section 3.14. The signatories hereto, including the AG, agree that, in conjunction with the AG, KACA, CAC, MHNA, and POWER, the Utilities will file plans for program administration with the Commission for year-round Home Energy Assistance ("HEA") programs in both of their respective service territories based solely upon a ten-cent per residential meter **per** month charge (the "HEA charge") for a period of three years. The HEA charge will be collected in the same manner as the DSM Cost Recovery Component of the Utilities' DSM Cost Recovery mechanism. The HEA programs shall be operated by existing social service providers ("Providers") with experience operating low-income energy assistance programs, who shall be entitled to recover actual operating expenses not to exceed ten percent (10%) of total HEA funds collected.

The signatories hereto, including the AG, agree that each HEA program will be subject to an outside independent annual audit conducted by an independent certified public accountant, in accordance with the Providers' existing audit requirements. Each audit shall include a detailed accounting of all expenses associated with administration of the program, which shall be **filed** annually with the Commission.

The signatories hereto, including the AG, further agree that KU shall be permitted recovery of its one-time information technology implementation costs through its DSM mechanism.

Section 3.15. The signatories hereto, including the AG, agree that the HEA programs to be filed shall have a commencement date of October 1,2004. Approval of this Settlement Agreement by the Commission shall constitute approval of the HEA parameters as proposed herein, subject to further review by the Commission of additional programmatic details. No money shall be distributed to the Providers pursuant to the HEA programs, or allocated pursuant to such programs, until such time as the Commission has issued final approval of the programmatic details.

Section 3.16. Within ninety days of the conclusion of the second year of the program, the Providers shall file with the Commission comprehensive program assessments to insure that the programs are meeting their respective established goals. Based upon those filings, and public hearings, if any, relating thereto, the Commission will then determine whether the HEA programs shall continue beyond three years and, if so, whether any modifications should be made to those programs.

Section 3.17. The signatories hereto, including the AG, who are parties to the respective Franklin Circuit Court actions hereby agree that upon approval of this Settlement Agreement by the Commission, they will jointly move the Franklin Circuit Court for the entry of an order dismissing the pending HEA and Pay As You Go ("PAYG") appeals, Civil Action Nos. 02-CI-00991 and 03-CI-00634, respectively.

Section 3.18. The signatories hereto, including the AG, agree that LG&E will phase out its PAYG program by limiting the program to existing customers and by removing those meters from existing customers as requested. as meters fail, or as customers move off the system. However, LG&E reserves the right to completely terminate the program upon sixty days advance notice to the Commission. LG&E and KU further agree that they will not seek approval of new prepaid metering programs for a period of at least five years from the date hereof, and that, after five years, approval by the Commission will be a necessary prerequisite to operating any new prepaid metering program.

Section 3.19. The signatories hereto, including the AG, agree that OMU NOx expenditures of $1 million per year incurred by KU pursuant to its contract with Owensboro Municipal Utility shall be recovered in KU's Environmental Cost Recovery filings pursuant to KRS 278.183. Recovery of the foregoing costs shall begin in April 2005 based upon the February 2005 expense month for KU.

Section 3.20. The signatories hereto, including the AG, agree that LG&E and KU shall offer a Curtailable Service Rider ("CSR1") to current customers who meet the eligibility requirements set forth in the proposed CSR1 tariff on such terms and conditions as specified in the proposed tariff subject to the following terms and conditions: (1) the customers shall be subject to curtailment for 250 hours annually; (2) the amount of the credit shall be $3.20 per kW for primary voltage customers and $3.10 per kW for transmission voltage customers; (3) the customers shall be entitled to 20 minutes notice of curtailment; (4) current customers shall have the option of buying through the curtailment at the market rate as determined by LG&E/KU; *(5)* in the event a customer elects to buy through a curtailment, the customer shall be required to purchase all of the demand to be curtailed on an hourly basis: and *(6)* this curtailable service rider is available only to those customers who are covered by an existing curtailable service rider as of the execution of this Settlement Agreement.

Section 3.21. The signatories hereto, including the AG, agree that new customers not currently served by an existing CSR will be eligible to take curtailable service under a new CSR tariff (CSR2) as originally filed by the Companies in the rate proceedings, except such customers will be able to buy through a request for curtailment only after having been on the CSR2 service for three years with no failure to curtail when requested.

Section 3.22. The signatories hereto, including the **AG,** agree that NAS's electric arc furnace operations shall receive electric service pursuant to the LI-TOD tariff, effective April 1, 2004, except as otherwise noted and which shall provide that the LI-TOD tariff shall be the same as the Non-Conforming Load Service Tariff ("NCLS") as proposed in Case No. 2003-00396 with the following changes:

(1) non-conforming load service shall be changed throughout to read large industrial-time of day (LI-TOD);

(2) the rates to be applied shall be the same rates applicable to customers on the LCI-TOD tariff;

(3) the demand charge shall he calculated by multiplying the rate established above by demand measured as Peak Demand **(KVA)** measured in 15 minute intervals plus the difference between Peak Demand measured in 5 minute intervals less Peak Demand measured in 15 minute intervals (if a positive number) multiplied by 0.5 times the rate, expressed as DC = [D15 +(D5-D15)0.5]R.

(4) Under the section of the tariff entitled System Contingencies and Industry System Performance Criteria the following additions are agreed:

a. The third sentence thereof shall be amended to limit the number of interruptions **per** month to no more than twenty with no carry-over from month to month. Within sixty days of the end of the applicable hilling period, upon request, information and documentation necessary for customer to verify that interruptions were caused by system contingencies as defined herein will be made available to customer;

b. Customers under the LI-TOD tariff may contract to curtail service upon notification by Company on the same terms and conditions as exist under the Curtailable Service Rider for LCI-TOD customers except requests for curtailment by the Companies shall not exceed 200 hours in the first year the Customer contracts for service, effective April 1, 2004, and 100 hours in each continuously succeeding year. Requests for curtailment shall he limited to on-peak periods specified in the LCI-TOD tariff.

c. All other provisions of the curtailable service rider as proposed in this Settlement Agreement for customers on the LCI-TOD tariff shall apply except that Customer may not buy through a request for curtailment by virtue of the unusual nature of the load of the Large Industrial class of customers.

d. System contingencies shall be defined in the tariff as:

In order to facilitate Company compliance with system contingencies and with NERC/ECAR System Performance Criteria, Customer will permit the Company to install electronic equipment and associated real time metering to permit Company interruption up to 95% of the Customer's load under this tariff when the LG&E Energy LLC System ("LEC System") experiences an unplanned outage or de-rate of LEC System-owned or purchased generation, or when Automatic Reserve Sharing is invoked within the ECAR or an ISO/RTO. LEC System as used herein shall consist of Company and Louisville Gas and Electric Company. Such equipment will electronically notify customer five (5) minutes before the electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes. The interruptions will not be accumulated and credited against the annual curtailment hours under this contract.

(5) Customers covered by the LI-TOD tariff as of **April 1**, 2004 shall have the option to contract for additional service for a period of not less

than five (5) years under the terms of the tariff by signing a contrzct for additional service by March 1, 2005 which commits service to begin, or to pay, demand charges as agreed in such contract no later than July 1, 2006 before the tariff is extended to other customers. If the option given to current customers herein is not exercised by the dates specified the option expires.

(6) The difference. if any, between the invoiced charges for electric service for the NAS electric arc furnace operations for the months of April, May, and June, 2004 actually paid by NAS and those charges ultimately billed as approved by the Commission shall be refunded to NAS as a billing credit going forward.

Section 3.23. The signatories hereto, including the AG, agree that, except as modified in this Settlement Agreement, the proposals of the Utilities in the rate proceedings shall be approved as filed.

ARTICLE IV. Miscellaneous Provisions.

Section 4.1. The signatories hereto, including the AG, agree that making this Settlement Agreement shall not be deemed in any respect to constitute an admission by any party hereto that any computation, formula, allegation, assertion or contention made by any other party in these proceedings is true or valid.

Section 4.2. The signatories hereto, including the AG, agree that the foregoing stipulations and agreements represent a fair, just and reasonable resolution of the issues addressed herein and request the Commission to approve the Settlement Agreement.

Section4.3. The signatories hereto, including the AG, agree that, following the execution of this Settlement Agreement, the signatories shall cause the Settlement Agreement to be filed with the Commission by May 11, 2004, together with a request to the Commission for consideration and approval of this Settlement Agreement.

Section 4.4. The signatories hereto, other than the Utilities and the AG, stipulate that they will withdraw the direct testimony of their witnesses in the rate proceedings. The signatories hereto, other than the AG, stipulate that they will not otherwise contest the Utilities' proposals in the rate proceedings regarding the subject matter of the Stipulation, and that they will refrain from cross-examination of the Utilities' witnesses during ihe rate proceedings, except insofar as such cross-examination is in support of the Stipulation.

Section 4.5. The signatories hereto, including the AG, agree that this Settlement Agreement is subject to the acceptance of and approval by the Public Service Commission. The signatones hereto, including the AG, further agree to act in good faith and to use their best efforts to recommend to the Commission that this Settlement Agreement be accepted and approved.

Section 4.6. The signatories hereto, including the **AG,** agree that, if the Commission does not accept and approve this Settlement Agreement in its entirety, then: (a) this Settlement Agreement shall be void and withdrawn by the parties hereto from further consideration by the Commission and none of the parties shall be bound by any of the provisions herein. provided that no party is precluded from advocating any position contained in this Settlement Agreement; and (b) neither the terms of this Settlement Agreement nor any matters raised during the settlement negotiations shall be binding on any of the signatones to this Settlement Agreement or be construed against any of the signatories.

Section 4.7. The signatories hereto, including the AG, agree that, should the Settlement Agreement be voided or vacated for any reason after the Commission has approved the Settlement Agreement, then the parties shall be returned to the ***status*** *quo* existing at the time immediately prior to the execution of this agreement.

Section **4.8.** The signatories hereto, including the AG, agree that this Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

Section4.9. The signatories hereto, including the AG, agree that this Settlement Agreement shall inure to the benefit of and be binding upon the parties hereto, their successors and assigns.

Section 4.10. The signatories hereto, including the AG, agree that this Settlement Agreement constitutes the complete agreement and understanding among the parties hereto, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

Section 4.11. The signatories hereto, including the AG, agree that, for the purpose of this Settlement Agreement only, the terms are based upon the independent analysis of the parties to reflect a fair, just and reasonable resolution of the issues herein and are the product of compromise and negotiation.

Section 4.12. The signatories hereto, including the AG, agree that neither the Settlement Agreement nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Settlement Agreement. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

Section 4.13. The signatories hereto, including the AG, warrant that they have informed, advised, and consulted with the respective parties hereto in regard to the contents and significance of this Settlement Agreement and based upon the foregoing are authorized to execute this Settlement Agreement on behalf of the parties hereto.

Section 4.14. The signatories hereto, including the AG, agree that this Settlement Agreement is a product of negotiation among all parties hereto, and no provision of this Settlement Agreement shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Settlement Agreement, the parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Settlement Agreement shall be implemented as written.

Section **4.15.** The signatories hereto, including the AG, agree that this Settlement Agreement may be executed in multiple counterparts.

IN WITNESS WHEREOF, the parties hereto have hereunto affixed their signatures.

Louisville Gas and Electric Company
and Kentucky Utilities Company

HAVE SEEN AND AGREED:

By: ______________________
Kendrick R. Riggs, Counsel

-and-

By: ______________________
Dorothy E. O'Brien. Counsel

Commonwealth of Kentucky, **ex.** rel. Gregory Stumbo, Attorney General, by and through the **Office** of Rate Intervention

HAVE SEEN **AND** AGREED:

By: ______________________________
Elizabeth E. Blackford, Counsel

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: ______________________

David F. Roehm, Counsel
Michael L. Kurtz, Counsel

Commonwealth of Kentucky,
Environmental and Public Protection Cabinet,
Division of Energy

HAVE SEEN AND AGREED:

By:______________________

Iris Skidmore, Counsel

United States Department of Defense

HAVE SEEN AND AGREED:

By: Peter E. Nyerges
for David A. McCormick, Counsel

The Kroger Co.

HAVE SEEN AND AGREED:

By: ______________________________
David C. Brown, Counsel

Kentucky Association for Community
Action, Inc.

HAVE SEEN AND AGREED:

By:______________________________
Joe F. Childers, Counsel

Community Action Council for
Lexington-Fayettc, Bourbon, Harrison
and Nicholas Counties. Inc.

HAVE SEEN AND AGREED:

By: ______________________________
Joe F. Childers, Counsel

Metro Human Needs Alliance

HAVE SEEN AND AGREED:

By: ______________________

Lisa Kilkelly, Counsel

People Organized and Working for Energy Reform

HAVE SEEN AND AGREED:

By: ______________________

Lisa Kilkelly, Counsel

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By. ______________________
David J. Barberie, Counsel

North American Stainless. L.P.

HAVE SEEN AND AGREED:

By: ______________________

Richard S. Taylor, Counsel

By: ______________________

Nathaniel K. Adams, Counsel

By: ______________________

Kimberly S. McCann, Counsel

Kentucky Utilities Company
Summary of Proposed Electric Rate Increase by Rate Class
For the 12 months Ended September 30,2002

	Adjusted Billings at Current Rates	Proposed Increase In Revenue Aa Filed	Percentage Increase	Settlement Increase	Percentage Increase	Increase as Percentage of Total
Residential	$ 252,910,745	$ 24,185,323	9.56%	$ 20,193,976	7.98%	43.763%
General Service	66,269,093	5,792,730	8.74%	$ 4,933,172	7.44%	10.691%
All Electric School Service Rate AES	3,955,546		0.00%	294,587	7.45%	0.638%
Combined LIghlIng & Power Service	226,957,349	18,885,564	8.32%	16,908,062	7.45%	36.642%
Comm./Industrial Time-of-Day	84,135,770	6,725,688	7.99%	2,048,936	2.44%	4.440%
Coal Mining Power Service	8,542,207	725.107	8.49%	638,188	7.47%	1.383%
Large Mine Power Time-of-Day	6,043,407	513.353	8.49%	453,462	7.50%	0.983%
Special Contract	14,551,478	(202,024)	-1.19%	(261.052)	-1.79%	-0.566%
Private Outdoor LIghlIng	13,396,416	1,179,334	8.80%	934,463	6.98%	2.025%
TOTAL ULTIMATE CONSUMERS	676,762,012	57,805,075	8.54%	46,143,794	6.82%	100.00%
Miscellaneous Service Revenue	999,716	1,003,763		408.443		
Rent from Electric Property	1,957,235	(556.373)		(556,373)		
TOTAL JURISDICTIONAL	679,718,963	58,252,465	8.57%	45,995,864	6.77%	

Kentucky Utilities Company
Summary of Proposed Increase
Based on Sales for the 12 Months Ended September 30.2003

	Adjusted Billings at Current Rates	Increase	Percentage Increase
Residential Rate RS	$ 121,233,915	$ 6,943,465	
Full Electric Residential Service Rate FERS	131,265,061	13.122.981	
Comb. Off-Peak Water Heating Rate CWH - RS	226.880	66.404	
Comb. Off-Peak Water Heating Rate CWH - FERS	184,889	61.127	
Total Residential	252.910,745	20.193.976	7.98%
General Service Rate GS - Secondary	63,054,553	4,464,741	
General Service Rate GS - Primary	2,543,978	233.163	
Comb. Off-Peak Water Heating Rate CWH - GS	2.434	798	
Electric Space Healing Rider - Rate 33	668.126	234,469	
Total General Service	66,269,093	4,933,172	7.44%
All Electric School Service Rate AES	3,955,546	294,587	7.45%
Combined Lighting 8 Power Service Rate LP - Secondary	155,582,998	12,488,035	
Combined Lighting 8 Power Service Rate LP - Primary	35,121,687	1.919.971	
Combined Lighting 8 Power Service Rate LP - Transmission	805.361	44,566	
Water Pumping Service Rate M	723,351	45,644	
High Load Factor Rate HLF Primary	22,475,293	1,496,550	
High Load Factor Rate HLF Secondary	12,248,660	913.296	
Total Combined Lighting & Power Service	226,957,349	16,908,062	7.45%
Large Comm./Industrial Time-of-Day Rate LCI-TOD Primary	65,546,566	1,621,297	
Large Comm./Industrial Time-of-Day Rate LCI-TOD Transmission	18,589,204	427.638	
Total Comm/Industrial Time-of-Day	84,135,770	2,048,936	2.44%
Coal Mining Power Service Rate MP Transmission	3,748,239	285.069	
Coal Mining Power Service Rate MP Primary	4,793,968	353.120	
Total Coal Mining Power Service	8,542,207	638.188	7.47%
Large Mine Power Time-of-Day Rate LMP-TOD Primary	1,944,714	148.303	
Large Mine Power Time-of-Day Rate LMP-TOD Transmission	4 098.693	305,159	
Total Large Mine Power Time-of-Day	6,043 407	453,462	7.50%
Special Contract	14,551,478	(261,052)	-1.79%
Street Lighting Service Rate St. Lt.	5,402,425	376,225	
Decorative Street Lighting Service Rate Dec. St. Lt.	807,559	56,815	
Private Outdoor Lighting Service Rate P.O. Lt.	6,293,269	438.616	
Customer Outdoor Lighting Service Rate C. O. Lt.	693,164	60.807	
Total Private Outdoor Lighting	13,396,416	934.463	6.98%
TOTAL ULTIMATE CONSUMERS	$ 676,762,012	$ 46,143,794	6.82%
Miscellaneous Service Revenue	999.716	408.443	
Rent from Electric Property	1,957,235	(556.373)	
TOTAL JURISDICTIONAL	679,718,963	45,995,864	6.77%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
RS - Rate Codes 010,050						
Customer Charges '(a)	2,708,953		$ 2.82	$ 7,639,247	$ 5.00	$ 13,544,765
First 100 KWH		260,463,182	$ 0.05017	13,067,438	$ 0.04404	11,470,799
Next 300 KWH		718,054,152	$ 0.04572	32,829,436	$ 0.04404	31,623,105
Next 600 KWH		913,350,525	$ 0.04172	38,104,984	$ 0.04404	40,223,957
Excess KWH		752,270,308	$ 0.04172	31,384,717	$ 0.04404	33,129,984
Sub-Total		2,644,138,167		$ 115,386,575		$ 116,447,845
Total Calculated at Base Rates				$ 123,025,822		$ 129.992.610
Correction Factor				0.999957		0.999957
Total After Application of Correction Factor				$ 123,031,152		$ 129,998,242
Fuel Clause Billings - proforma for rollin				1,946,159		1,946,159
Merger Surcredit				(2,974,607)		(2,974,607)
Value Delivery Surcredit				(367,155)		(367,155)
VDT Amortization & Surcredit Adjustment				15,547		15,547
Adjustment to Reflect Year-End Customers				(417,181)		(440.805)
Total Rate RS				$ 121,233,915		$ 128,177,380
Proposed Increase						6,943,465
Percentage Increase						5.73%

KU Exhibit 1

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
CWH - Rate Code 120, RS						
Customer Charges '(a)	51,243		$ 1.03	$ 52,780		$
First 100 KWH		4,042,164	$ 0.02665	107,724	$ 0.04404	178,017
Next 300 KWH		2,852,289	$ 0.02665	76,013	$ 0.04404	125,615
Next 600 KWH		193,230	$ 0.02665	5,150	$ 0.04404	8,510
Excess KWH		0	$ 0.02665		$ 0.04404	
Subtotal		7,087,683		$ 188,887		$ 312,142
Total Calculated at Base Rates				$ 241,667		$ 312,142
Correction Factor				0.999750		0.999750
Total After Application of Correction Factor				$ 241,727		$ 312,220
Fuel Clause Billings - proforma for rollin				5,535		5,535
Merger Surcredit				(5,712)		(5,712)
Value Delivery Surcredit				(679)		(679)
VDT Amortization & Surcredit Adjustment				29		29'
Adjustment to Reflect Year-End Customers				(14,020)		(18,108)
Total Rate CWH / RS				$ 226,880		$ 293,284
Proposed Increase						66,404
Percentage Increase						29.27%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
FERS - Rate Codes 020,060,080						
Customer Charges "(a)	1,983,477		$ 3.85	$ 7,636,386	$ 5.00	$ 9,917,385
First 1,000 KWH		1,686,402,755	$ 0.04229	71,317,973	$ 0.04404	74,269,177
Excess KWH		1,358,217,822	$ 0.03836	52,101,236	$ 0.04404	59,815,913
Sub-Total		3,044,620,577		$ 123,419,208		$ 134,085,090
Total Calculated at Base Rates				$ 131,055,595		$ 144,002,475
Correction Factor				0.999917		0.999917
Total After Application of Correction Factor				$ 131,066,473		$ 144,014,428
Fuel Clause Billings - proforma for rollin				1,905,058		1,905,058
Merger Surcredit				(3,110,470)		(3,110,470)
Value Delivery Surcredit				(383,963)		(383,963)
VDT Amortization & Surcredit Adjustment				16,258		16,258'
Adjustment to Reflect Year-End Customers				1,771,704		1,946,729
Total Rate FERS				$ 131,285,061		$ 144,386,041
Proposed Increase						13.1 22,981
Percentage Increase						10.00%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
CWH - Rate Codes **122** FERS						
Customer Charges "(a)	36,730		$ 1.03	$ 37.832	$ -	$ -
First 1,000 KWH		5,846,032	$ 0.02665	155,797	$ 0.04404	257,459
Excess KWH		0	$ 0.02665		$ 0.04404	
Sub-Total		5,846,032		$ 155,797		$ 257,459
Total Calculated at Base Rates				$ 193.629		$ 257,459
Correction Factor				0.999892		0.999892
Total After Application of Correction Factor				$ 193,650		$ 257,487
Fuel Clause Billings - proforma for rollin				4,573		4,573
Merger Surcredit				(4,584)		(4,584)
Value Delivery Surcredit				(550)		(550)
VDT Amortization & Surcredit Adjustment				23		23
Adjustment to Reflect Year-End Customers				(8,223)		(10,934)
Total Rate CWH / FERS				**$ 104,009**		**$ 246,016**
Proposed increase						**61,127**
Percentage Increase						33.06%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
GSS - Rate Codes 110, 113, 150, 153, 710						
Customer Charges '(a)	822,782		$ 4.11	$ 3,381,634	$ 10.00	$ 8,227,820
First 500 KWH		250,675,964	$ 0.06443	16,151,052	$ 0.05327	13,353,509
Next 1,500 KWH		340,305,160	$ 0.05332	18,145,071	$ 0.05327	18,128,056
Excess KWH		514,894,841	$ 0.04870	25,075,379	$ 0.05327	27,428,448
Sub-Total		1,105,875,966		$ 59,371,502		$ 58,910,013
Total Calculated at Bare Rates				$ 62,753,136		$ 67,137,833
Correction Factor				0.994771		0.994771
Total After Application of Correction Factor				$ 63,083,006		$ 67,490,751
Fuel Clause Billings - proforma for rollin				831,532		831,532
Merger Surcredit				(1,498,838)		(1,498,838)
Value Delivery Surcredit				(184,691)		(184,691)
VDT Amortization & Surcredit Adjustment				7,821		7,821
Adjustment to Reflect Year-End Customers				815,724		872,720
Total Rate GS Secondary				$ 63,054,553		$ 67,519,294
Proposed Increase						4,464,741
Percentage Increase						7.08%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
GSP - Rate Codes 111, 151						
Customer Charges "(a)	1,127		$ 4.11	$ 4,632	$ 10.00	$ 11,270
First 500 KWH		461,154	$ 0.06443	29,712	$ 0.05327	24,566
Next 1,500 KWH		1,168,955	$ 0.05332	62,329	$ 0.05327	62,270
Excess KWH		50,497,087	$ 0.04870	2,459,208	$ 0.05327	2,689,980
Sub-Total		52,127,196		$ 2,551,249		$ 2,776,816
Primary Service Discounts				(142,440)		(155,381)
Minimum Billings				156,810		171,057
Total Calculated at Base Rates				$ 2,570,251		$ 2,803,762
Correction Factor				1.001490		1.001490
Total After Application of Correction Factor				$ 2,566,427		$ 2,799,590
Fuel Clause Billings - proforma for rollin				45,451		45,451
Merger Surcredit				(61,024)		(61,024)
Value Delivery Surcredit				(7,181)		(7,181)
VDT Amortization & Surcredit Adjustment				304		304
Adjustment to Reflect Year-End Customers				-		
Total Rate GS Primary				$ 2,543,978		$ 2,777,141
Proposed Increase						233,163
Percentage Increase						9.17%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
CWH - Rate Codes 126 GS						
Customer Charges '(a)	901		$ 1.03	$ 928		$
First 500 KWH		68,163	$ 0.02665	1,817	$ 0.05327	3,631
Next 1,500 KWH		342	$ 0.02665	9	$ 0.05327	18
Excess KWH		0	$ 0.02665		$ 0.05327	
Sub-Total		66,505		$ 1,826		$ 3,649
Total Calculated at Base Rates				$ 2,754		$ 3,649
Correction Factor				1.000019		1.000019
Total After Application of Correction Factor				$ 2,754		$ 3,649
Fuel Clause Billings - proforma for rollin				51		51
Merger Surcredit				(64)		(64)
Value Delivery Surcredit				(7)		(7)
VDT Amortization & Surcredit Adjustment				0		0
Adjustment to Reflect Year-End Customers				(299)		(396)
Total Rate CWH / GS				$ 2,434		$ 3,233
Proposed Increase						798
Percentage Increase						32.79%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
33 - Rate Code 330 GS						
Customer Charges *(a)	11,530		$ -	$	$ -	$
First 500 KWH		3,040,894	$ 0.03926	119,385	$ 0.05327	161,988
Next 1,500 KWH		4,522,308	$ 0.03926	177,546	$ 0.05327	240,903
Excess KWH		9,709,702	$ 0.03926	381,203	$ 0.05327	517,236
Sub-Total		17,272,904		$ 678,134		$ 920,128
Minimum Billings				23,562		23,562
Total Calculated at Base Rates				$ 701,696		$ 943,690
Correction Factor				1.002812		1.002812
Total After Application of Correction Factor				$ 699,728		$ 941,043
Fuel Clause Billings - proforma for rollin				6,006		6,006
Merger Surcredit				(15,915)		(15,915)
Value Delivery Surcredit				(1,924)		(1,924)
VDT Amortization & Surcredit Adjustment				81		81
Adjustment to Reflect Year-End Customers				(19,849)		(26,694)
Total Rate 33				$ 668,128		$ 902,598
Proposed Increase						234,469
Percentage Increase						35.09%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPS/AES - Rate Coda 220						
Number of Customers	3.474					
Demand	367,906		$ -	$	$ -	$
First 500,000 KWH		100,707,601	$ 0.03936	3,963,851	$ 0.04227	4,256,910
Next 1,500,000 KWH		0	$ 0.03936		$ 0.04227	
Excess KWH		0	$ 0.03936		$ 0.04227	
Sub-Total		100,707,601		$ 3,963,851		$ 4,256,910
Minimum Billings				6,022		6,022
Total Calculated at Base Rates				$ 3.969.873		5 4,262,932
Correction Factor				0.994813		0.994813
Total After Application of Correction Factor				$ 3,990,570		$ 4,285,158
Fuel Clause Billings - proforma for rollin				70,235		70,235
Merger Surcredit				(94,157)		(94,157)
Value Delivery Surcredit				(11,594)		(11,594)
VDT Amortization & Surcredit Adjustment				491		491
Adjustment to Reflect Year-End Customers						
Total Rate AES				$ 3,955,546		$ 4,250,133
Proposed Increase						294,587
Percentage Increase						7.45%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPS - Rate Codes **562,568**						
Number of Customers	154,715				$ 75.00	$ 11,603,625
Demand	10,678,854		$ 4.11	$ 43,890,092	$ 6.65	71,014,382
Minimum Annual Charges				136,444		220,767
First 500,000 KWH		3,874,329,937	$ 0.02872	111,270,756	$ 0.02200	85,235,259
Next 1,500,000 KWH		61,080,231	$ 0.02633	1,608,242	$ 0.02200	1,343,765
Excess KWH		0	$ 0.02504		$ 0.02200	
Sub-Total		3,935,410,168		$ 112,878,998		$ 86,579,024
Total Calculated at Base Rates				$ 156,905,534		$ 169,417,797
Correction Factor				0.998130		0.998130
Total After Application of Correction Factor				$ 157,199,484		$ 169,735,188
Fuel Clause Billings - proforma for rollin				3,170,805		3,170,805
Merger Surcredit				(3,748,979)		(3,748,979)
Value Delivery Surcredit				(460,016)		(460,016)
VDT Amortization & Surcredit Adjustment				19,479		19,479
Adjustment to Reflect Year-End Customers				(597,774)		(645,443)
Total Rate LP Secondary				$ **155,582,998**		**$ 168,071,034**
Proposed Increase						**12,488,035**
Percentage Increase						8.03%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPP - Rate Codes **561,566**						
Number of Customers	3,656				$ 75.00	$ 274,200
Demand	2,381,439		$ 3.13	$ 7,453,905	$ 6.26	14,907,810
CSR Credits	43,289		$ (3.20)	(138,526)	$ (3.20)	(138,526)
CSR Penalties				2,411		2,411
First 500,000 KWH		639,927,383	$ 0.02872	18,378,714	$ 0.02200	14,078,402
Next 1,500,000 KWH		331,775,188	$ 0.02633	8,735,641	$ 0.02200	7,299,054
Excess KWH		26,286,146	$ 0.02504	658,205	$ 0.02200	578,295
Sub-Total		997,988,716		$ 27,772,560		$ 21,955,752
Total Calculated at Base Rates				$ 35,090,351		$ 37,001,647
Correction Factor				0.998820		0.998820
Total After Application of Correction Factor				$ 35,131,814		$ 37,045,369
Fuel Clause Billings - proforma for rollin				814,739		814,739
Merger Surcredit				(843,553)		(843,553)
Value Delivery Surcredit				(103,491)		(103,491)
VDT Amortization & Surcredit Adjustment				4,382		4,382
Adjustment to Reflect Year-End Customers				117,795		124,211
Total Rate LP Primary				**$ 35,121,687**		**$ 37,041,656**
Proposed Increase						**1,919,971**
Percentage Increase						5.47%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPT - Rate Codes 560,567						
Number of Customers	27				$ 75.00	$ 2,025
Demand	36.408		$ 2.97	$ 108.133	$ 5.92	215,538
Minimum Annual Charges				1,522		3,034
First 500,000 KWH		6,109,950	$ 0.02872	175,478	$ 0.02200	134,419
Next 1.500.000 KWH		9,366,902	$ 0.02633	246,631	$ 0.02200	206,072
Excess KWH		0	$ 0.02504		$ 0.02200	
Sub-Total		15,476,852		$ 422,108		$ 340,491
Total Calculated at Base Rates				$ 531,763		$ 561.087
Correction Factor				0.993946		0.993946
Total Afler Application of Correction Factor				$ 535,002		$ 564,505
Fuel Clause Billings - proforma for rollin				11,436		11,436
Merger Surcredit				(12,742)'		(12,742)
Value Delivery Surcredit				(1,567)		(1,567)
VDT Amortization & Surcredit Adjustment				66'		66
Adjustment to Reflect Year-End Customers				273,166		288,230
Total Rate LP Transmission				$ **805,361**		$ **849,927**
Proposed Increase						**44,566**
Percentage Increase						5.53%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LCIP - Rate Code 563						
Number of Customers	315				$ 120.00	$ 37.800
On-Peak Demand	4,068,204		$ 4.14	$ 16,842,364	$ 4.58	18,632,374
Off-Peak Demand	3,969,563		$ 0.73	$ 2,897,781	$ 0.73	2,897,781
CSR Credits	64.834		$ (3.20)	$ (207,469)	$ (3.20)	(207,469)
Penalties				21,553		21,553
Energy		2,080374,735	$ 0.02210	45,987,332	$ 0.02200	45,779,244
Total Calculated at Base Rates				$ 65,541,561		$ 67,161,283
Correction Factor				0.999029		0.999029
Total After Application of Correction Factor				$ 65,605,294		$ 67,226,592
Fuel Clause Billings - proforma for rollin				1,698,726		1,698,726
Merger Surcredit				(1,573,353)		(1,573,353)
Value Delivery Surcredit				(192,241)		(192,241)
VDT Amortization & Surcredit Adjustment				8,140		8,140
Adjustment to Reflect Year-End Customers						
Total Rate LCI Primary				$ 65,546,566		$ 67,167,863
Proposed Increase						1,621,297
Percentage increase						2.47%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
EASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)		(5)	(6)		(7)
	Bills / KW	Total KWH	Present Rates		Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates		Calculated Revenue @ Proposed Rates
LCIT - Rate Code 564								
Number of Customers	48					$ 120.00	$	5,760
On-Peak Demand	1,099,952		$ 3.95	$	4,344,810	$ 4.39		4,828,789
Off-Peak Demand	1,092,494		$ 0.73		797.521	$ 0.73		797,521
CSR Credits	122.014		$ (3.10)		(378,243)	$ (3.10)		(378,243)
Penalties					76,807			76,807
Energy		621,047,926	$ 0.02210		13,725,159	$ 0.02200		13,663,054
Total Calculated at Base Rates				$	18,566,054		$	18,993,688
Correction Factor					0.999990			0.999990
Total After Application of Correction Factor				$	18,566,238		$	18,993,876
Fuel Clause Billings - proforma for rollin					526,690			526,690
Merger Surcredit					(450,942)			(450,942)
Value Delivery Surcredlt					(55,1 17)			(55,117)
VDT Amortization & Surcredit Adjustment					2,334			2,334
Adjustment to Reflect Year-End Customers								
Total Rate LCI Transmission				$	18,589,204		$	19,016,842
Proposed Increase								427,630
Percentage Increase								2.30%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
HLFP - Rate Code **571**						
Number of Customers	529				$ 75.00	$ 39,675
Demand	1,345,913		$ 4.79	$ 6,446,922	$ 6.26	**8,425,414**
Energy		723,323,088	$ 0.02270	16,419,434	$ 0.02200	15,913.108
Minimum Billings				38,375		50,151
Total Calculated at Base Rates				$ 22.904.731		$ 24.428.349
Correction Factor				0.994328		0.994328
Total After Application of Correction Factor				$ 23,035,385		$ 24,567,694
Fuel Clause Billings - proforma for rollin				591,757		591,757
Merger Surcredit				(550,321)		(550,321)
Value Delivery Surcredit				(66,795)		(66,795)
VDT Amortization & Surcredit Adjustment				2,828		2,828
Adjustment to Reflect Year-End Customers				(537,561)		(573,319)
Total Rate HLF Primary				$ **22,475,293**		**$ 23,971,843**
Proposed Increase						**1,496,550**
Percentage Increase						6.66%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
HLFS - Rate Code 572						
Number of Customers	494				$ 75.00	$ 37,050
Demand	705,460		$ 5.13	$ 3,619,007	$ 6.65	4,691,306
Energy		370,430,550	$ 0.02270	8,408,773	$ 0.02200	8,149,472
Minimum Billings				203,871		264,277
Total Calculated at Base Rates				$ 12,231,651		5 13,142,105
Correction Factor				0.996888		0.996888
Total After Application of Correctlon Factor				$ 12,269,841		$ 13,183,137
Fuel Clause Billings - proforma for rollin				305,857		305,857
Merger Surcredit				(292,805)		(292,805)
Value Delivery Surcredit				(35,747)		(35,747)
VDT Amortization & Surcredit Adjustment				1,514,		1,514
Adjustment to Reflect Year-End Customers						-
Total Rate HLF Secondary				5 12,248,660		$ 13,161,955
Proposed Increase						913.296
Percentage Increase						7.46%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Rate M - Rate Code 650						
Customer Charges '(a)	1,151		$ 10.27	$ 11,821	$ 75.00	$ 86,325
Demand Charges	46,351.6		$ -	$	$ 6.65	$ 308,238
First 10,000 KWH		6.1 36,374	$ 0.04631	284.175	$ 0.02200	135,000
Excess KWH		10,959,266	$ 0.03917	429,274	$ 0.02200	241,104
Sub-Total		17,095,640		$ 713,450		$ 376,104
Total Calculated at Base Rates				$ 725,271		$ 770,667
Correction Factor				0.994581		0.994581
Total After Application of correction Factor				$ 729,223		$ 774,866
Fuel Clause Billings - proforma for rollin				13,459		13,459
Merger Surcredit				(17,302)		(17,302)
Value Delivery Surcredit				(2,118)		(2,118)
VDT Amortization & Surcredit Adjustment				90'		90
Adjustment to Reflect Year-End Customers						
Total Rate M Water Pumping				$ 723,351		$ 768,995
Proposed Increase						45,644
Percentage Increase						6.31%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
EASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
MPT - Rate Codes 680,687						
Number of Customers	183				$ 75.00	$ 13,725
Demand	335,459		$ 2.67	$ 895.675	$ 4.57	1,533,046
First 500,000 KWH		55,158,510	$ 0.02881	1,589.117	$ 0.02400	1,323,804
Excess KWH		59,532,090	$ 0.02540	1,512,115	$ 0.02400	1,428,770
Sub-Total		114,690,600		$ 3,101,232		$ 2,752.574
Total Calculated at Base Rates				$ 3,996,906		$ 4,299,346
Correction Factor				0.988697		0.988697
Total After Application of Correction Factor				$ 4,042,601		$ 4,348,498
Fuel Clause Billings - proforma for rollin				87.711		87,711
Merger Surcredit				(95,856)		(95,656)
Value Delivery Surcredit				(11,653)		(11,653)
VDT Amortization & Surcredit Adjustment				493		493
Adjustment to Reflect Year-End Customers				(275,257)		(296,085)
Total Rate MP Transmission				**$ 3,746,239**		**$ 4,033,308**
Proposed Increase						**285,069**
Percentage Increase						7.61%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
MPP - Rate Codes 681,686						
Number of Customers	261				$ 75.00	$ 19,575
Demand	473.781		$ 3.01	$ 1,428,082	$ 4.69	2,222,034
First 500,000 KWH		89,036,933	$ 0.02881	2,565,154	$ 0.02400	2,136,886
Excess KWH		38,740,167	$ 0.02540	984,000	$ 0.02400	929,764
Sub-Total		127,777,100		$ 3,549,154		$ 3,086,650
Minimum Annual Charges				64,223		100,068
Total Calculated at Base Rates				$ 5,039,459		$ 5,408,328
Correction Factor				0.996149		0.996149
Total After Application of Correction Factor				$ 5,058,939		$ 5,429,234
Fuel Clause Billings - proforma for rollin				103.480		103,480
Merger Surcredit				(119,812)		(119.812)
Value Delivery Surcredit				(14,613)		(14,813)
VDT Amortization & Surcredit Adjustment				619'		619
Adjustment to Reflect Year-End Customers				(234,645)		(251,820)
Total Rate MP Primary				$ 4,793,968		$ 5,147,088
Proposed Increase						353,120
Percentage Increase						7.37%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement 'Rates	Calculated Revenue @ Proposed Rates
LMPP - Rate Code 683						
Number of Customers	25				$ 120.00	$ 3,000
On-Peak Demand	160,687		$ 4.14	$ 665,243	$ 5.39	866,102
Off-Peak Demand	160,665		$ 0.73	117,266	$ 0.73	117,286
Energy		56,287,872	$ 0.02094	1,178,668	$ 0.02000	1,125,757
Minimum Annual Billings				(8,760)		(11,405)
Total Calculated at Base Rates				$ 1,952,437		$ 2,100,740
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 1,952,437		$ 2,100,740
Fuel Clause Billings - proforma for rollin				43.817		43,817
Merger Surcredit				(46,196)		(46,196)
Value Delivery Surcredit				(5,581)		(5,581)
VDT Amortization & Surcredit Adjustment				236		236
Adjustment to Reflect Year-End Customers						
Total Rate LMP Primary				**$ 1,944,714**		**$ 2,093,017**
Proposed Increase						**148,303**
Percentage Increase						7.63%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LMPT - Rate Code 664						
Number of Customers	82				$ 120.00	$ 9,840
On-Peak Demand	400,744		$ 3.80	$ 1,522,827	$ 4.85	1,943,608
Off-Peak Demand	381,990		$ 0.73	278,853	$ 0.73	278,853
Energy		135,342,000	$ 0.02094	2,834,061	$ 0.02000	2,706,840
Minimum Annual Billings				197,968		252,670
Total Calculated at Base Rates				$ 4,833,710		$ 5,191,811
Correction Factor				1.002250		1.002250
Total Afler Application of Correction Factor				$ 4,822,860		$ 5,180,158
Fuel Clause Billings - proforma for rollin				106,921		106,921
Merger Surcredit				(114,208)		(114,208)
Value Delivery Surcredit				(13,680)		(13,680)
VDT Amortization & Surcredit Adjustment				579'		579
Adjustment to Reflect Year-End Customers				(703,778)		(755,917)
Total Rate LMP Transmission				$ 4,098,693		$ 4,403,852
Proposed Increase						305,159
Percentage Increase						7.45%
Total LMP				$ 6,043,407		$ 6,496,869
Proposed Increase						453.462
Percentage Increase						7.50%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Special Contract - Rate Code **720**						
Non-Interruptible Demand	408,840		$ 3.89	$ 1,590,387	$ 3.98	$ 1,627,182
Interruptible Demand			$ 1.86		$ 1.95	
Energy		256,027,222	$ 0.02148	5,499,465	$ 0.02200	5,632,599
Total Calculated at Base Rates				$ 7,089,852		$ 7,259,781
Correction Factor				1.000241		1.000241
Total After Application of Correction Factor				$ 7,088,146		$ 7,258,034
Fuel Clause Billings - proforma for rollin				206.387		206.387
Merger Surcredit				(170,246)		(170,246)
Value Delivery Surcredit				(20,695)		(20,695)
VDT Amortization & Surcredit Adjustment				876		876
Adjustment to Reflect Year-End Customers						
Total **WestVaCo** Special Contract				**$ 7,104,468**		**$ 7,274,357**
Proposed Increase						**169,889**
Percentage increase						2.39%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KVA *KW*	Total KWH	Present Rates	Calculated Revenue @ Present NCL Rate (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Special Contract Billing Code 723,724,725,726						
Non-Interruptible/On-Peak Deme	962,182		$ 5.58	$ 5,368,976	$ 4.39	$ 4,223,979
Interruptible/Off-Peak Demand	987,308		$ 1.03	$ 1,016,927	$ 0.73	$ 720,735
CSR Credit	887,629		$ (3.10)	$ (2,751,649)	$ (3.10)	$ (2,751,649)
Energy		224,499,600	$ 0.01750	3,928,743	5 0.02200	4,938,991
Total Calculated at Base Rates				$ 7,562,997		$ 7,132,056
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 7,562,997		$ 7,132,057
Fuel Clause Billings - proforma for rollin				200,577		200,577
Merger Surcredit				(283,568)		(283,568)
Value Delivery Surcredit				(34,456)		(34,456)
VDT Amortization & Surcredit Adjustment				1,459		1,459
Adjustment to Reflect Year-End Customers						
Total NAS Special Contract				$ 7,447,010		$ 7,016,069
Proposed increase						(430,941)
Percentage Increase						-5.79%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
FWP - Rate Code 740 *(c)						
Energy		0	$ 0.03598		$ 0.03598	
Total Calculated at Base Rates						
Correction Factor						
Total After Application of Correction Factor						
INCREASE IN BASE RATES REVENUE						

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Street Lighting	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates	Settlement Rates	Calculated Revenue @ Proposed Rates
Incandescent Street Lighting (1)				(see Exhibit 9)		
I-1000-std	42,730	1,203	$ 2.11	$ 2,538	$ 2.26	$ 2,719
I-2500-std	1,293,398	18,532	$ 2.57	47,627	$ 2.75	50,963
I-4000-std	768.860	7,034	$ 3.68	25,885	$ 3.94	27,714
I-6000-std	12,762	84	$ 4.89	411	$ 5.24	440
I-10000-std	0	0	$ 6.57		$ 7.03	
I-1000-orn	0	0	$ 2.72		$ 2.91	
I-2500-orn	6,432	96	$ 3.32	319	$ 3.55	341
I-4000-orn	58,859	540	$ 4.56	2,462	$ 4.88	2,635
I-6000-orn	7,152	48	$ 5.07	282	$ 6.29	302
I-10000-orn	0	0	$ 8.07		$ 8.64	
Mercury Vapor Street Lighting						
MV-3500-std	0	0	$ 5.36		$ 6.60	
MV-7000-std	1,199,867	17,126	$ 6.19	106,010	$ 6.63	113,545
MV-10000-std	1,220,047	12,442	$ 7.14	88.836	$ 7.64	95,057
MV-20000-std	3,216,852	20,879	$ 8.39	175,175	$ 8.98	187,493
MV-3500-orn	0	0	$ 7.60		$ 8.14	
MV-7000-orn	102,988	1,492	$ 8.30	12,384	$ 8.89	13,264
MV-10000-orn	674,672	6,882	$ 9.01	62,007	$ 9.65	66,411
MV-20000-orn	2,851,854	18,790	$ 9.89	185,833	$ 10.59	198,986

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Street Lighting -continued	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates	Settlement Rates	Calculated Revenue @ Proposed Rates
High Pressure Sodium Street Lighting				(see Exhibit 9)		
HPS-4000-std	1,706,461	84.016	$ 4.68	393,195	$ 5.00	420.080
HPS-5800-std	2,821,602	97,770	$ 5.08	496.672	$ 5.43	530.891
HPS-9500-std	8,471,266	211,989	$ 5.72	1,212,577	$ 6.11	1,295,253
HPS-22000-std	4,975,937	60,024	$ 8.44	506,603	$ 9.02	541,416
HPS-50000-std	1,435,313	8,864	$ 13.62	120,728	$ 14.55	128,971
HPS-4000-orn	953,042	47,651	$ 7.13	339,752	$ 7.62	363,101
HPS-5800-orn	2,927,333	105,857	$ 7.53	797,103	$ 8.04	851,090
HPS-9500-orn	1,092,981	27,793	$ 8.35	232,072	$ 8.92	247,914
HPS-22000-orn	3,822,835	47,250	$ 11.06	522,585	$ 11.81	558,023
HPS-50000-orn	827,689	5,095	$ 16.23	82,692	$ 17.34	88.347
Sub-Total	40,490,932	801,457		$ 5,413,746		$ 5,784,957
Partial Month billings				86,450		92,378
Total Calculated at Base Rates				$ 5,500,195		$ 5,877,334
Correction Factor				1.000190		1.000190
Total After Application of Correction Factor				$ 5,499,149		$ 5,876,216
Fuel Clause Billings - proforma for rollin				30,519		30,519
Merger Surcredit				(129,056)		(129,056)
Value Delivery Surcredit				(15,744)		(15,744)
Adjustment to Reflect Year-End Customers				16.889		18.047
VDT Amortization & Surcredit Adjustment				667		667
Total Rate St. Lt.				$ 5,402,425		$ 5,780,650
Proposed increase						378,225

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Street Lighting -- Decorative						
HPS-A-4000-Dec	0	0	$ 9.74	$	$ 10.40	$
HPS-A-5800-Dec	1,992	72	$ 10.24	737	$ 10.94	788
HPS-A-9500-Dec	48,347	1,231	$ 10.87	13,381	$ 11.61	14,292
HPS-A-4000-His	29,279	1,464	$ 15.28	22,370	$ 16.32	23,892
HPS-A-5800-His	11,621	420	$ 15.77	6.623	$ 16.85	7,077
HPS-A-9500-His	144,939	3,677	$ 16.41	60,340	$ 17.53	64,458
HPS-4000 col	130,976	6,556	$ 6.42	42,090	$ 6.86	44,974
HPS-5800 col	174,991	6,208	$ 6.83	42.401	$ 7.30	45,318
HPS-9500 col	371,159	9,455	$ 7.40	69,967	$ 7.90	74,695
HPS-5800 coa	0	0				
HPS-9500 coa	0	0				
HPS-5800 con	634,990	22,944	$ 11.80	270,739	$ 12.60	289.094
HPS-9500 con	173,631	4,452	$ 14.05	62,551	$ 15.01	66.825
HPS-22000 con	268,604	3,329	$ 16.29	54,229	$ 17.40	57,925
HPS-50000 can	157,439	939	$ 21.09	19,804	$ 22.53	21,156
HPS-16000 Granville	3,611	63	$ 44.60	2,810	$ 47.64	3,001
HPS-16000 Granville A	83.872	1,666	$ 35.84	59,709'	$ 38.28	63,774
HPS-16000 Granville B	12,666	256	$ 58.78	15,048	$ 62.79	16,074
HPS-16000 Granville C	19,859	399	$ 39.50	15,761	$ 42.19	16,834
HPS-16000 Granville D	2,103	45	$ 41.12	1,850	$ 44.92	2,021
HPS-16000 Granville E	649	13	$ 42.24	549	$ 46.14	600
HPS-16000 Granville F	3,500	70	$ 56.94	3,986	$ 62.21	4,355
HPS-16000 Granville G	6,093	122	$ 55.32	6,749	$ 59.09	7,209
HPS-16000 Granville H	0	0	$ 40.70		$ 44.48	
HPS-16000 Granville I	1,296	26	$ 36.96	961	$ 40.38	1,050
HPS-16000 Granville A1	8,946	179	$ 51.66	9,247	$ 55.18	9,877
HPS-16000 Granville B1	0	0	$ 74.60		$ 79.69	
HPS-16000 Granville E l	649	13	$ 58.06	755	$ 63.43	825

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER), 2003

(1)	)	(:		(4)		(5)		(6)		(7)
	KWH	Total Lights		Present Rates		Calculated Revenue @ Present Rates (see Exhibit 9)		Settlement Rates		Calculated Revenue @ Proposed Rates
Street Lighting -- Decorative - continued										
HPS-16000 Granville A2	7,930	160	$	51.66		8,266	$	55.18		8.829
HPS-16000 Granville 83	2,101	42	$	52.78		2,217	$	56.38		2.368
HPS-16000 Granville G I	1,190	24	$	55.32		1,328	$	59.09		1,418
HPS-16000 Granville 82	11,773	236	$	53.92		12,725	$	58.91		13,903
Sub-Total	2,314,206	64,061			$	807,191			$	862.631
Partial Month billings						6,975				7,454
Total Calculated at Base Rates					$	814,165			$	870.085
Correction Factor						0.999016				0.999016
Total After Application of Correction Factor				141,960	$	814,967			$	870,942
Fuel Clause Billings - proforma for rollin						1,736				1,736
Merger Surcredit						(19,076)				(19,076)
Value Delivery Surcredit						(2,409)				(2.409)
Adjustment to Reflect Year-End Customers						12,240'				13.081
VDT Amortization & Surcredit Adjustment						102				102
Total Rate Dec St. Lt.					$	807,559			$	864,374
Proposed Increase										**56,815**

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Private Outdoor Lighting						
Standard (Served Overhead)						
MV-7000-OB	2,542,058	36,524	$ 7.12	$ 260,051	$ 7.61	$ 277,948
MV-20000-Cobr	1,214,151	8,012	$ 8.41	67,381	$ 8.98	11,948
HPS-5800-OB	70,769	2,534	$ 4.05	10,263	$ 4.33	10,972
HPS-9500-OB	13,810,099	350.344	$ 4.62	1,618,589	$ 4.94	1,730,699
HPS-22000-Cobr	1,268,099	15,631	$ 8.44	131,926	$ 9.02	140,992
HPS-50000-Cobr	4,403,511	27,021	$ 13.62	368,026	$ 14.55	393,156
Directional (Served Overhead)						
HPS-9500	4,431,410	112,584	$ 5.60	630,470	$ 5.98	673,252
HPS-22000	5,191,668	64,058	$ 7.93	507,980	$ 8.47	542,571
HPS-50000	13,251,698	81,371	$ 12.08	982,962	$ 12.90	1,049,686
)ecorative (Served Underground)						
HPS-4000 coa decr	'478	24	$ 9.74	234	$ 10.40	250
HPS-5800 coa decr	3,464	120	$ 10.24	1,229	$ 10.94	1,313
HPS-9500 coa decr	76,594	1,961	$ 10.88	21,336	$ 11.62	22,787
HPS-4000 coa hist	19,923	996	$ 15.28	15.219	$ 16.32	16,255
HPS-5800 coa hist	11,318	410	$ 15.77	6,466	$ 16.85	6,909
HPS-9500 coa hist	222,699	5,706	$ 16.42	93,693	$ 17.54	100,083
HPS-5800 coa	0	0	$ 23.47		$ 25.07	
HPS-9500 coa	64,116	1,644	$ 24.09	39,604	$ 25.73	42,300
HPS-4000 col	12,719	636	$ 6.42	4,083	$ 6.86	4,363
HPS-5800 col	35,199	1,272	$ 6.83	8,688	$ 7.30	9,286
HPS-9500 col	509,423	13,046	$ 7.40	96,540	$ 7.90	103,063
HPS-5800 con	16,935	612	$ 11.80	7,222	$ 12.60	7.711
HPS-9500 con	90,992	2,341	$ 14.05	32,891	$ 15.01	35,138
HPS-22000 con	546,476	6,756	$ 16.29	110,055	$ 17.40	117,554
HPS-50000 con	1,624,326	10,033	$ 21.09	211,596	$ 22.53	226,043

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBEI 30,2003

(1)	(2) KWH	(3) Total Lights	(4) Present Rates	(5) Calculated Revenue @ Present Rates (see Exhibit 9)	(6) Settlement Rates	(7) Calculated Revenue @ Proposed Rates
Private Outdoor Lighting - continued						
Metal Halide Directional						
MH-12000	209,687	3,026	$ 8.27	25,025	$ 8.83	26,720
MH-12000-WP	47,049	679	$ 10.10	6,858	$ 10.79	7.326
MH-12000-MP	3,328	48	$ 16.10	773	$ 17.20	826
MH-32000	3,174,956	21,013	$ 11.46	240,809	$ 12.24	257,199
MH-32000-WP	759,074	5,025	$ 13.30	66,833	$ 14.21	71,405
MH-32000-MP	162,468	1,085	$ 19.29	20,930	$ 20.81	22,362
MH-107800	5,180,248	14,272	$ 23.67	337,818	$ 25.28	360,796
MH-107800-WP	1,426,641	3,899	$ 26.22	102,232	$ 28.01	109,211
MH-107800-MP	290,486	806	$ 31.50	25,389	$ 33.65	27,122
Metal Halide Contemporary						
MH-12000-con	36,536	528	$ 9.29	4,905	$ 9.92	5,238
MH-12000-con-MP	121,818	1,764	$ 17.13	30,217	$ 18.30	32,281
MH-32000-con	306,662	2,035	$ 12.90	26,252	$ 13.78	28,042
MH-32000-con-MP	665,690	4,424	$ 20.73	91,710	$ 22.14	97,947
MH-107800-con	314,967	869	$ 26.04	22,629	$ 27.82	24,176
MH-107800-con-MP	694,079	1,925	$ 33.88	65,219	$ 36.19	69,666
Sub-Total	62,811,814	805,034		$ 6,294,099		$ 6,724,596
Partial Month billings				49,671		53,069
Total Calculated at Base Rates				$ 6,343,770		$ 6,777,664
Correction Factor				1.000377		1.000377
Total Afler Application of Correction Factor				$ 6,341,376		$ 6,775,107
Fuel Clause Billings - proforma for rollin				48,198		48,198
Merger Surcredit				(149,592)		(149,592)
Value Delivery Surcredit				(18,946)		(18,946)
VDT Amortization & Surcredit Adjustment				802		802
Adjustment to Reflect Year-End Customers				71,430		76,316
Total Rate P.O. Lt.				$ 6,293,269		$ 6,731,885
Proposed Increase						438,616

KENTUCKY UTILITIES COMPANY
ATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED)N SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates	Settlement Rates	Calculated Revenue @ Proposed Rates
Customer Outdoor Lighting				(see Exhibit 9)		
Inc-2500 (move to St. Lt) (1)	9,660	144	$ 5.12	$ 737	$ 7.61	$ 1,096
MV-3500 (move to St. Lt) (1)	20,097	478	$ 6.25	2,988	$ 7.61	3,638
MV-7000 (move to St. Lt.) (1)	8,411,057	120.910	$ 7.14	863,297	$ 7.61	920,125
Special Lighting	950,602	6,274	$ 6.16	38.648	$ 6.58	41,283
Speclai Lighting	359,447	2,218	$ 8.21	18,210	$ 8.77	19,452
Subtotal	9,750,863	130,024		$ 923.880		$ 985,593
Partial month billings				5,701		6,082
Total Calculated at Base Rates				$ 929,581		$ 991,675
Correction Factor				1.000087		1.000087
Total After Application of Correction Factor				$ 929,500		$ 991,589
Fuel Clause Billings - proforma for rollin				7,246		7,246
Merger Surcredit				(21,779)		(21,779)
Value Delivery Surcredit				(2,723)		(2,723)
VDT Amortization & Surcredit Adjustment				115		115
Adjustment to Reflect Year-End Customers				(19,194)		(20,476)
Total Rate C.O. Lt.				5 893,164		5 953,970
Proposed Increase						60.807

Louisville Gas and Electric Company
Summary of Settlement Electric Rate Increase by Rate Class
For the 12 months Ended September 30,2002

	Adjusted Billings at Current Rates	Proposed Increase In Revenue As Filed	Percentage Increase	Increase Per Settlement	Percentage increase	Percentage of Total
Residential	$ 220,310,529	$ 26,430,885	12.00%	$ 18,708,395	8.49%	43.148%
General Service	83,504,883	8,978,115	10.75%	6,483,208	7.76%	14.952%
Large Commercial Rate LC	132,177,625	13,708,637	10.37%	10,242,386	7.75%	23.622%
Industrial Power Rate LP	100,837,138	10,100,134	10.02%	5,625,092	5.58%	12.973%
Special Contracts	28,070,944	3,028,038	10.79%	1,422,016	5.07%	3.280%
Street Lighting	11,678,144	1,386,185	11.87%	877,787	7.52%	2.024%
TOTAL ULTIMATE CONSUMERS	$ 576,579,264	$ 63,631,994	11.04%	$ 43,358,883	7.52%	100.00%
Increase in Miscellaneous Charges	848,569	133,331		45,302		
TOTAL INCREASE IN REVENUE	$ 577,427,833	$ 63	11.04%	$ 43,404,185	7.52%	

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF SETTLEMENT ELECTRIC RATE INCREASE BY RATE CLASS
BASED ON ADJUSTED SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
REVISED TO INCLUDE JANUARY 2004 ECR BASE RATES ROLLIN

Rate Class	Calculated Test Period Billings as Modified to Reflect Janaury 2004 ECR Rollin Rates	Settlement Increase in Revenue	Percentage Increase
Residential Rate R	$ 219,577,320		
Residential Water Heating	733,209.04		
Total Residential	220,310,529	$ 18,708,395	8.49%
General Service Rate GS	83,495,405		
Commercial Water Heating	9,479		
Total General Service	83,504,883	6,483,208	7.76%
Large Commercial Rate LC			
Primary	6,577,911		
Secondary	100,311,410		
Primary	10,683,797		
Secondary	14,604,508		
Total Rate LCTOD	132,177,625	10,242,386	7.75%
Industrial Power Rate LP			
Primary	4,567,163		
Secondary	25,929,168		
Transmission	11,530,567		
Primary	56,811,559		
Secondary	1,998,682		
Total Rate LPTOD	100,837,138	5,625,092	5.58%
Special Contracts			
Special Contracts	6,890,944		
Special Contracts			
Special Contracts	4,895,550		
Special Contracts	6,624,286		
Special Contracts	7,845,834		
Special Contracts	1,814,330		
Total Special Contracts	28,070,944	1,422,016	5.07%
Public Street Lighting Rate PSL	4,910,190		
Street Lighting Energy Rate SLE	142,487		
Outdoor Lighting Rate OL	6,066,969		
Traffic Lighting Rate TLE	558,499		
	11,678,144	877,787	7.52%
Total Ultimate Consumers	$ 576,579,264	$ 43,358,883	7.52%
Increase in Miscellaneous Charges	$ 715,238	$ 45,302	6.33%
Total Increase In Revenue	$ 577,294,502	$ 43,404,185	7.52%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
EASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
RESIDENTIAL RATE R						
Customer Charges	4,037,207		$ 3.40	$ 13,726,504	$ 5.00	$ 20,166,035
Energy Charges		kWh's				
First 600 kWh - Summer Season		704,635,241	$ 0.06149	43,328,021	$ 0.05867	41,481,877
Over 600 kWh - Summer Season		876,768,392	$ 0.06319	55,402,995	$ 0.05867	51,615,355
First 600 kWh - Winter Season		1,267,566,536	$ 0.05669	72,992,260	$ 0.05867	75,799,160
Over 600 kWh - Winter Season		973,572,745	$ 0.04370	42,545,129	$ 0.05687	57,314,227
Total Energy				214,268,405		226,210,619
Total Rate R @ base rates		3,842,544,916		$ 227,994,909		$ 246,396,654
RESIDENTIAL PREPAID METERING RPP						
Facilities Charges	5,462		$ 2.05	$ 11.197	$ 2.05	$ 11,197
Customer Charges	5,462		$ 3.40	16.571	$ 5.00	27.310
		kWh's				
Energy Charges		5,164,866	$ 0.05661	293,416	$ 0.05667	304,056
Total Prepaid Metering RPP @ base rates				$ 323.184		$ 342,563
Subtotal @ base rates before application of correction factor				$ 228,318,093		$ 246,739,217
Correction Factor -			1.002361		1.002361	
Subtotal @ base rates after application of Correction factor		3,847,709,782		$ 227,780,293		$ 246,158,026
Fuel Adjustment Clause. proforma for rollin				(1,499,234)		(1,499,234)
Merger Surcredit				(6,469,016)		(6,469,016)
Value Delivery Surcredit				(1,464,356)		(1,484,358)
VDT Amortization & Surcredit Adjustment				17,356		17,356
Adjustment to Reflect Year-End Customers		21,505,743		1,232,279		1,336,006
TOTAL RESIDENTIAL RATES R & RPP				I 219,577,320		I 238,058,781
PROPOSED INCREASE						$ 18,481,461
Percentage Increase						6.42%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
WATER HEATING RATE WH						
Residential Water Heating						
Customer Charges	73.228		$ 0.97	$ 71,031	$ -	$
Energy Charges		kWh's				
Summer Season		4,808,217	$ 0.04132	198.678	$ 0.05887	283.060
Winter Season		12,388,791	$ 0.04132	511.905	$ 0.05887	729.328
		17,197,008				
Total Residential Water Heating @ base rates		17,197,008		$ 781.612		$ 1,012,388
Commercial Water Heating						
Customer Charges	1.501		$ 0.97	$ 1,456	$ -	$
Energy Charges		kWh's				
Summer Season		67.741	$ 0.04132	2,799	$ 0.07086	4.800
Winter Season		141.564	$ 0.04132	5.849	$ 0.06313	8.937
		209,305				
Total Commercial Water Heating @ base rates		209,305		$ 10.104		$ 13,737
Subtotal @ base rates before application of correction factoi				I 791,716		$ 1,026,125
Correction Factor -			1.003426		1.003426	
Subtotal @ base rates after application of correction factor		17,408,313		I 789,012		I 1,022,621
Fuel Adjustment Clause - proforma for rollin				(10.373)		(10,373)
Merger Surcredit				(21.169)		(21.169)
Value Delivery Surcredit				(4,846)		(4,846)
VDT Amortization & Surcredit Adjustment				57		57
Adjustment to Reflect Year-End Customers		(229,190)		(9,993)		(13,095)
TOTAL WATER HEATING RATE WH				742.688		I 973,185
PROPOSED INCREASE						$ 230,507
Percentage Increase						31.04%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
GENERAL SERVICE RATE GS						
Customer Charges - Sungle Phase	329,431		$ 4.02	$ 1,324,313	$ 10.00	$ 3,294,310
Customer Charges - Three Phase	156,788		$ 8.05	1,262,143	$ 15.00	2,351,820
Energy Charges		*kWh's*				
Summer Season		505,580,412	$ 0.06865	34,708,095	$ 0.070 8	35,825,428
Winter Season		799,975,176	$ 0.06092	48,734,488	$ 0.063 3	50,502,433
Total Energy				83,442,583		86,327,861
Primary Service Discounts				(27,354)		(29,245)
Total Rate GS @ base rates		1,305,555,588		$ 86,001,685		$ 91,944,746
SPACE HEATING RIDER TO RATE GS						
Customer Charges	9,221		$ 2.33	$ 21,485	$	$ -
Energy Charges		*kWh's*				
Summer Season			$ -	-	$ 0.07086	-
Winter Season		29,731,262	$ 0.04372	1,299,851	$ 0.06313	1,876,935
Total Space Heating Rider @ base rates		29,731,262		$ 1,321,336		$ 1,876,935
Subtotal @ base rates before application of correction factor				**$ 87,323,020**		**$ 93,821,681**
Correction Factor -			0.999589		0.999589	
Subtotal @ base rates after application of correction factor		1,335,286,850		**$ 87,358,902**		**$ 93,860,233**
Fuel Adjustment Clause - proforma for rollin				(621,080)		(621,080)
Merger Surcredit				(2,417,927)		(2,417,927)
Value Delivery Surcredit				(551,407)		(551,407)
VDT Amortization & Surcredit Adjustment				6,447		6,447
Adjustment to Reflect Year-End Customers		(4,415,970)		(279,531)		(301,226)
TOTAL GENERAL SERVICE RATE GS & SH RIDER				**$ 83,495,405**		**$ 89,975,041**
PROPOSED INCREASE						**$ 6,479,636**
Percentage Increase						7.76%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
LARGE COMMERCIAL RATE LC - PRIMARY VOLTAGE									
Customer Charges	531	$	17.70	5	9,399	$	65.00	5	34,515
Demand Charges	*kW-Months*								
Summer Season	127,056	$	8.44		1,072,353	$	12.32		1,565,330
Winter Season	214.932	$	5.64		1,212,216	$	9.52		2,046,153
	341.968								
	kWh's								
Energy Charges	154,967,220	5	0.02959		4,565,480	$	0.02349		3,640,180
Subtotal @ base rates before application of correction factor				I	6,879,448			I	7286.178
Correction Factor -			0.999428				0.999426		
Subtotal @ base rates after application of correction factor				I	6,883,383			I	7290,346
Fuel Adjustment Clause - proforma for rollin					(72,627)				(72,627)
Merger Surcredit					(190,189)				(190,189)
Value Delivery Surcredit					(43.162)				(43.162)
VDT Amortization & Surcredit Adjustment					505				505
Adjustment to Reflect Year-End Customers	#REF!								
TOTAL LARGE COMMERCIAL RATE LC PRIMARY				$	6,577,911			I	6,984,873
PROPOSED INCREASE								$	406.962
Percentage Increase									6.19%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
LARGE COMMERCIAL RATE LC .SECONDARY VOLTAGE						
Customer Charges	30,959		$ 17.70	$ 547,974	5 65.00	5 2,012,335
Demand Charges		kW-Months				
Summer Season		1,823,049	$ 10.32	18,813,866	$ 14.20	25,887,296
Winter Season		3,242,275	$ 7.26	23,538,917	5 11.14	36.118,944
		5,065,324				
		kWh's				
Energy Charges		2,059,176,673	$ 0.02959	60,931,038	5 0.02349	48,370,060
Subtotal @ base rates before application of correction factoı				$ 103,831,794		$ 112,388,634
Correction Factor -			0.999428		0.999428	
Subtotal @ base rates after application of correction factor				$ 103,891,193		$ 112,452,929
Fuel Adjustment Clause. pmforma for rollin				(1,002,645)		(1,002,645)
Merger Surcredit				(2,866,140)		(2,866,140)
Value Delivery Surcredit				(651,470)		(651,470)
VDT Amortization 6 Surcredit Adjustment				7,617		7,617
Adjustment to Reflect Year-End Customers		19,155,120		932.854		1,013,228
TOTAL LARGE COMMERCIAL RATE LC SECONDARY				$ 100,311,410		$ 108,953,519
PROPOSED INCREASE						$ 8,642,109
Percentage Increase						8.62%
Total Large Commercial Rate LC				$ 106,889,321		$ 115,938,392
PROPOSED INCREASE						$ 9,049,072
Percentage Increase						8.47%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roil-In Rater		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rater
LARGE COMMERCIAL RATE LCTOD - PRIMARY VOLTAGE									
Customer Charges	123	$	19.76	$	2,433	$	90.00	$	11,070
	kW-Months								
Basic Demand Charges	520,367	$	1.98		1,030,327	$	2.17		1,129,196
Peak Demand Charges	*kW-Months*								
Summer Peak	194,877	$	6.63		1,292,035	$	10.15		1,978,002
Winter Peak	322.246	$	3.54		1,140,756	$	7.35		2,368,523
	517,125								
	kWh's								
Energy Charges	261,433,800	$	0.02963		7,746,263	$	0.02349		6,141,060
Subtotal @ base rates before application of correction factor				$	11,211,636			$	11,627,871
Correction Factor -			1.002249				1.002249		
Subtotal @ base rates after application of correction factor				I	11,166,675			$	11,601,776
Fuel Adjustment Clause - proforma for rollin					(125,669)				(125.669)
Merger Surcredit					(306,135)				(306.135)
Value Delivery Surcredit					(69,688)				(69,688)
VDT Amortization 8 Surcredit Adjustment					615				815
Adjustment to Reflect Year-End Customers									
TOTAL LARGE COMMERCIAL RATE LCTOD PRIMARY				$	10,663,797			I	11,098,899
PROPOSED INCREASE								$	415,102
Percentage Increase									3.89%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
LARGE COMMERCIAL RATE LCTOD .SECONDARY VOLTAGE						
Customer Charges	604		$ 19.76	$ 11,947	5 90.00	5 54,360
		kW-Months				
Basic Demand Charges		671.385	$ 3.68	2,470,697	$ 3.22	2,161,860
Peak Demand Charges		*kW-Months*				
Summer Peak		232,987	$ 6.63	1,544,704	$ 10.98	2,558,197
Winter Peak		433,763	$ 3.54	1,535,521	5 7.92	3,435,403
		666,750				
		kWh's				
Energy Charges		308,993,871	$ 0.02963	9,155,488	$ 0.02349	7,258,266
Subtotal @ base rates before application of correction **factor**				$ 14,718,357		I **15,468,086**
Correction Factor -			1.002249		1.002249	
Subtotal @ base rates after application of correction factor				I **14,685,327**		$ **15,433,373**
Fuel Adjustment Clause. proforma for rollin .				(153,023)		(153,023)
Merger Surcredit				(403,395)		(403,395)
Value Delivery Surcredit				(91.549)		(91,549)
VDT Amortization & Surcredit Adjustment				1.070		1,070
Adjustment to Reflect Year-End Customers		12,359,754		568.077		596,243
TOTAL LARGE COMMERCIAL RATE LCTOD SECONDARY				$ **14,604,508**		I 15,382,720
PROPOSED INCREASE						$ 778.212
Percentage Increase						5.33%
TOTAL LARGE COMMERCIAL RATE LCTOO				$ **25,288,305**		I **26,481,619**
PROPOSED INCREASE						$ 1,193,314
Percentage Increase						4.72%
TOTAL LARGE COMMERCIAL (LC and LC-TOD)				$ **132,177,625**		$ 142,420,011
PROPOSED INCREASE						$ 10,242,388
Percentage Increase						7.75%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LP - TRANSMISSION VOLTAGE					
Customer Charges		5 43.78	$	$ 90.00	5
Demand Charges	*kW-Months*				
Summer Season		$ 7.59		$ 11.35	
Winter Season		$ 5.00		$ 8.76	
	kWh's				
Energy Charger		$ 0.02542		$ 0.02000	
Power Factor Provision	*kW-Months*				
Summer Season		5 7.59		$ 11.35	
Winter Season		$ 5.00		$ 8.76	
Subtotal @ base rates before application of correction factor			$ -		$
Correction Factor.					
Subtotal @ base rates after application of correction factor			$		$
Fuel Adjustment Clause. proforma for rollin					
Merger Surcredit					
Value Delivery Surcredit					
VDT Amortization & Surcredit Adjustment					
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LP PRIMARY					$ -
PROPOSED INCREASE					$ -
Percentage Increase					

Note: Currently no customers are served under this rate

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LP - PRIMARY VOLTAGE					
Customer Charges	494	$ 43.78	$ 21,627	$ 90.00	$ 44,460
Demand Charger	kW-Months				
Summer Season	95,177	$ 8.78	835,654	$ 12.55	1,194,471
winter Season	181,277	$ 6.17	1,118,479	$ 9.96	1,805,519
	276,454				
	kWh's				
Energy Charges	111,622,714	$ 0.02542	2,837,449	$ 0.02000	2,232,454
Power Factor Provision	kW-Months				
Summer Season	(806)	$ 8.78	(7,077)	$ 12.55	(10,115)
Winter Season	(3,501)	$ 6.17	(21,601)	$ 9.96	(34.870)
	(4,307)				
Subtotal @ base rates before application of correction factor			$ 4,784,532		$ 5,231,919
Correction Factor -		0.999681		0.999681	
Subtotal @ base rates after application of correction factor			$ 4,706,080		$ 5,233,590
Fuel Adjustment Clause - proforma for rollin			(58.665)		(58.665)
Merger Surcredit			(130,757)		(130,757)
Value Delivery Surcredit			(29,824)		(29,824)
VDT Amortization & Surcredit Adjustment			349		349
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LP PRIMARY			$ 4,567,163		$ 5,014,693
PROPOSED INCREASE					$ 447,530
Percentage Increase					9.80%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LP -SECONDARY VOLTAGE								
Customer Charges	4,225		$ 43.76	$	184,971	5 90.00	$	380.250
Demand Charges		*kW-Months*						
Summer Season		485.652	$ 10.69		5,300,656	$ 14.35		7.115.476
Winter Season		927,407	$ 8.11		7,521,271	$ 11.76		10,906,306
		1,423,259						
		kWh's						
Energy Charges		553,636,275	$ 0.02542		14,078,518	$ 0.02000		11,076,726
Power Factor Provision		*kW-Months*						
Summer Season		(4,581)	$ 10.69		(48,971)	$ 14.35		(65,737)
Winter Season		(10,121)	$ 6.11		(82,061)	$ 11.76		(119,023)
		(14,702)						
Subtotal @ base rates before application of correction factor				$	26,954,365		I	29,293,998
Correction Factor -			0.999661			0.999681		
Subtotal @ base rates after application of correction factor				$	26,962,971		$	29,303,351
Fuel Adjustment Clause - proforma for rollin					1277.626)			(277.626)
Merger Surcredit					(738,856)			(736.656)
Value Delivery Surcredit					(167.175)			(167,175)
M T Amortization & Surcredit Adjustment					1,965			1,955
Adjustment to Reflect Year-End Customers		3,146,798			147.900			161,327
TOTAL INDUSTRIAL POWER RATE LP SECONDARY				$	25,929,168		$	28,282,975
PROPOSED INCREASE							I	2,353,807
Percentage increase								9.08%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON ES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT :S REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN API TO TEST PERIOD LING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LPTOD .TRANSMISSION VOLTAGE									
Customer Charges	73	$	45.81	$	3.344	$	120.00	$	8.760
	kW-Months								
Basic Demand Charges	696.768	$	2.10		1,463,255	$	2.33		1,623,516
Peak Demand Charges	*kW-Months*								
Summer Peak	234.813	$	5.50		1,291,472	$	9.02		2,116,013
Winter Peak	454,878	$	2.92		1,328,244	$	6.43		2,924,866
	689,691								
	kWh's								
Energy Charges	376,359,726	$	0.02542		9,567,064	$	0.02000		7,527,195
Power Factor Provision	*kW-Months*								
Basic Demand	(25.159)	$	2.10		(52,834)	$	2.33		(58.620)
Summer Peak	(7,762)	$	5.50		(42,691)	$	9.02		(70.013)
Winter Peak	([illegible]215)	$	2.92		(50.268)	$	6.43		(110,692)
	kW-Months								
Interruptible Service Rider	411,322	$	(3.30)		(1,357,363)	5	(3.10)		(1,275,098)
Subtotal @ base rates before application of correction factor				$	12,150,223			$	. 12,687,925
Correction Factor .			1.000343				1.000343		
Subtotal @ base rates after application of correction factor				I	12,146,053			$	12,083,570
Fuel Adjustment Clause - proforma for rollin					(213,291)				(213,291)
Merger Surcredit					(328.889)				(328.889)
Value Delivery Surcredit					(74,173)				(74.173)
VDT Amortization & Surcredit Adjustment					867				867
Adjustment lo Reflect Year-End Customers									
TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION				$	11,530,567			$	12,068,084
PROPOSED INCREASE								$	537,517
percentage Increase									4.66%
TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION (without Interruptible Credit)				I	12,887,929			$	13,343,182
PROPOSED INCREASE (without **Interruptible Credit)**								$	455.253
percentage increase									3.53%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LPTOD - PRIMARY VOLTAGE					
Customer Charges	540	$ 45.61	$ 24.737	$ 120.00	$ 64,800
	kW-Months				
Basic Demand Charges	2,963,564	$ 3.29	9,750,126	$ 3.52	10,431,745
Peak Demand Charges	*kW-Months*				
Summer Peak	996.472	$ 5.50	5,480,596	$ 9.03	8,998,142
Winter Peak	1,952,825	$ 2.92	5,702,249	$ 6.44	12,576,193
	2,949,297				
	kWh's				
Energy Charges	1,597,360,760	$ 0.02542	40,604,911	$ 0.02000	31,947,215
Power Factor Provision	*kW-Months*				
Basic Demand	(103,903)	$ 3.29	(341,840)	$ 3.52	(365,737)
Summer Peak	(41,348)	$ 5.50	(227.4121	$ 9.03	(373,369)
Winter Peak	(58,2311	$ 2.92	(170,035)	$ 6.44	(375.008)
	kW-Months				
Interruptible Service Rider	344.897	$ (3.30)	(1,138,160)	$ (3.20)	(1,103,670)
Subtotal @ bare rates before application of correction factoı			$ 59,685,172		$ 61,800,311
Correction Factor -		1.000342		1.000342	
Subtotal @ base rates after application of correction factor			$ 59,664,762		$ 61,779,178
Fuel Adjustment Clause - proforma for rollin			(864,770)		(864,770)
Merger Surcredit			(1,626,347)		(1,626,347)
Value Delivery Surcredit			(366.371)		(366,371)
VOT Amortization *8* Surcredit Adjustment			4.284		4.284
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY			$ 56.81 1,559		$ 58,925,974
PROPOSED INCREASE					$ 2,444,446
Percentage Increase					3.72%
TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY (without Interruptible Credit)			$ 57,949,719		$ 60,029,644
PROPOSED INCREASE (without Interruptible Credit)					$ 2,079,926
Percentage Increase					3.59%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LPTOD - SECONDARY VOLTAGE					
Customer Charges	151	$ 45.81	$ 6,917	$ 120.00	$ 18,120
	kW-Months				
Basic Demand Charges	114,966	$ 5.25	603.572	$ 4.62	531.143
Peak Demand Charges	*kW-Months*				
Summer Peak	31.727	$ 5.50	174,499	$ 9.73	308.704
Winter Peak	80,068	$ 2.92	233,799	$ 7.14	571.666
	111.795				
	kWh's				
Energy Charges	42,810,915	$ 0.02542	1,088253	$ 0.02000	856,218
Power Factor Provision	*kW-Months*				
Basic Demand	(1,951)	$ 5.25	(10.243)	$ 4.82	(9,014)
Summer Peak	(533)	$ 5.50	(2,932)	$ 9.73	(5,186)
Winter Peak	(1.404)	$ 2.92	(4.100)	$ 7.14	(10.025)
Subtotal @ base rates before application of correction factor			$ 2,089,765		I 2,281,846
Correction Factor -		1.000343		1.000343	
Subtotal @ base rates after application of correction factor			I 2,089,048		$ 2,260,870
Fuel Adjustment Clause - proforma lor rollin			(21,506)		(21,506)
Merger Surcredit			(56.520)		(56.520)
Value Delivery Surcredit			(12.486)		(12,486)
VOT Amortization & Surcredit Adjustment			146		146
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LPTOD SECONDARY			$ 1,998,882		$ 2,170,504
PROPOSED INCREASE					I 171,822
Percentage Increase					8.80%
TOTAL INDUSTRIAL POWER RATE LESS INTERRUPTIBLE CREDIT			$ 103,332,661		I 108,840,999
PROPOSED INCREASE					$ 5,508,337
Percentage Increase					5.33%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED *TO* TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
Demand Charger	*kW-Months*				
Summer Season	154.000	$ 6.43	1,298,220	$ 11.94	1,838,760
winter Season	216.450	$ 6.24	1,350,648	5 9.75	2,110,388
	370.450				
	kWh's				
Energy Charges	195,880,000	$ 0.02437	4,773,596	$ 0.02000	3,917,600
Power Factor Provision	*kW-Months*				
Summer Season	(11.539)	$ 8.43	(97.275)	$ 11.94	(137.778)
Winter Season	(16,4501	$ 6.24	(102.649)	$ 9.75	(160,389)
	(27.969)				
Subtotal @ base rates before application of correction factor			$ 7,222,539		$ 7,568,580
Correction Factor -		1.000000		1.000000	
Subtotal @ base rates after application of correction factor			$ 7,222,538		$ 7,568,580
Fuel Adjustment Clause. proforma for rollin			(66.299)		(86.299)
Merger Surcredit			(199.899)		(199,899)
Value Delivery Surcredit			(45,934)		(45.934)
VDT Amortization & Surcredit Adjustment			537		537
TOTAL SPECIAL CONTRACT			I 6,890,944		I 7,236,985
PROPOSED INCREASE					$ 346,041
Percentage Increase					5.02%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SAI ES FOR THE 12 MONTHS ENDED ! EPTEMBEF 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
	kW-Months				
Demand Charges	221.864	$ 11.01	2,442,723	$ 11.15	2,473,784
	kWh's				
Energy Charges	145,699,200	$ 0.01852	2,898,349	16 0.02000	2,913,984
Subtotal @ base rater before application of correction factor			I 5,141,072		$ 5,387,768
Correction Factor-		1.000000		1.000000	
Subtotal @ base rates after application of correction factor			I 5,141,072		$ 5,387,788
Fuel Adjustment Clause. proforma for rollin			(75.153)		(75.153)
Merger Surcredit			(139,387)		(139,387)
Value Delivery Surcredit			(31,349)		(31,349)
VDT Amortization 8 Surcredit Adjustment			367		367
TOTAL SPECIAL CONTRACT			$ 4,895,550		$ 5,142,246
PROPOSED INCREASE					$ 248.896
Percentage Increase					5.04%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
SPECIAL CONTRACT									
Customer Charger	12	$	74.29	$	891	5	120.00	$	1,440
	kW-Months								
Basic Demand Charges	402,555	$	5.93		2,387,151	$	6.30		2,536,097
Peak Demand Charges	*kW-Months*								
Summer Peak	137,065	$	8.19		1,122,562	$	7.65		1,048,547
Winter Peak	238,810	$	3.81		909.866	$	3.27		780.909
	375,875								
	kWh's								
Energy Charges	155,404,800	5	0.01751		2,721,138	$	0.02000		3,108,096
Power Factor Provision	*kW-Months*								
Basic Demand	(16.663)	$	5.93		(110.671)	5	6.30		(117,576)
Summer Peak	(6,720)	$	8.19		(55.036)	5	7.65		(51.407)
Winter Peak	(10,724)	5	3.61		(40.860)	5	3.27		(35,068)
	kW-Months								
interruptible Service Rider		$				$	(3.30)		
Subtotal @ base rates before application of correction factor				$	6,935,043			$	7271.037
Correction Factor-			1.000000				1.000000		
Subtotal @ base rates after application of correction factor				$	6,935,043			$	7,271,037
Fuel Adjustment Clause. proforma for rollin					(76.751)				(76.751)
Merger Surcredit					(191,055)				(191.055)
Value Delivery Surcredit					(43.460)				(43.460)
VDT Amortization & Surcredit Adjustment					508				508
TOTAL SPECIAL CONTRACT				$	6,624,286			$	6,960,280
PROPOSED INCREASE								$	335.994
Percentage Increase									5.07%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
Customer Charger	12	$ 74.29	$ 891	$ 74.29	$ 891
	kW-Months				
Basic Demand Charges	624,000	$ 4.36	2,720,640	$ 4.62	2,882,880
Peak Demand **Charges**	*kW-Months*				
Summer **Peak**	180,000	$ 8.19	1,474,200	$ 7.65	1,377,000
Winter Peak	360,000	$ 3.81	1,371,600	$ 3.27	1,177,200
	540,000				
	kWh's				
Energy Charges	199,644,549	$ 0.01751	3,495,776	$ 0.02000	3,992,891
P a e r Factor Provision	*kW-Months*				
Basic Demand	(49,504)	$ 4.36	(215,837)	$ 4.62	(228.708)
Summer **Peak**	(14,040)	$ 8.19	(114.988)	$ 7.65	(107.408)
Winter Peak	(28,800)	$ 3.81	(109,7281	5 3.27	(94,176)
	kW-Months				
Interruptible Service Rider	120.000	$ (3.30)	(396,000)	$ (3.10)	(372.000)
Station House Credit			(1,200)		(1,200)
Subtotal @ base rates before application of correction factor			$ 8,225,354		$ 8,627,312
Correction Factor.		1.000078		1.000078	
Subtotal @ base rates after application **of** correction factor			$ 8,224,717		$ 8,626,703
Fuel Adjustment Clause - **proforma** for rollin			(102,665)		(102,665)
Merger Surcredit			(225,529)		(225.529)
Value Delivery Surcredit			(51.289)		(51,289)
VDT **Amortization &** Surcredit **Adjustment**			600		600
TOTAL SPECIAL CONTRACT			$ 7,845,834		$ 8,247,820
PROPOSED INCREASE					$ 401,986
Percentage increase					5.12%
TOTAL SPECIAL CONTRACT (without Interruptible Credit)			8 241 034		$ 8,619,820
PROPOSED INCREASE					$ 377,986
Percentage increase					4.59%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
	kW-Months				
Demand Charges	104,943	5 7.53	790.221	$ 8.33	874,175
	kWh's				
Energy Charges	56.404.800	5 0.01975	1,115,772	$ 0.01088	1,123,117
Subtotal @ base rates before application of correction factor			$ 1,905,993		$ 1,997,292
Correction Factor -		1.000000		1.000000	
Subtotal @ base rates after application of correction factor			$ 1,905,993		$ 1,997,292
Fuel Adjustment Clause. proforma for rollin			(28.377)		(28,377)
Merger Surcredit			(51.718)		(51.718)
Value Delivery Surcredit			(11,705)		(11.705)
VDT Amortization 6 Surcredit Adjustment			137		137
TOTAL SPECIAL CONTRACT			$ 1,814,330		$ 1,905,829
PROPOSED INCREASE					$ 91,299
Percentage Increase					5.03%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
STREET LIGHTING ENERGY RATE SLE		*kWh's*				
Energy Charges		3,992,315	$ 0.03788	151,229	$ 0.04059	162,048
Subtotal @ base rates before application of correction factor				$ **151,229**		$ **162,048**
Correction Factor -			1.001986		1.001986	
Subtotal @ base rates after application of correction factor				$ **150,929**		$ **161,727**
Fuel Adjustment Clause - proforma for rollin				(2,325)		(2,325)
Merger Surcredit				(4,081)		(4,081)
Value Delivery Surcredit				(887)		(887)
VDT Amortization & Surcredit Adjustment				10		10
Adjustment to Reflect Year-End Customers		(31,939)		(1,159)		(1,247)
TOTAL STREET LIGHTING ENERGY RATE SLE				$ **142,487**		$ **153,197**
PROPOSED INCREASE						$ **10,711**
Percentage Increase						7.52%
TRAFFIC LIGHTING ENERGY RATE TLE						
Customer Charges	10,370		$2.54	$ 26,340	$ 2.80	$ 29,036
		kWh's				
Energy Charges		11,472,338	$ 0.04777	548,034	$ 0.05114	586,695
Subtotal @ base rates before application of correction factor				$ **574,373**		$ **615,731**
Correction Factor -			0.993299		0.993299	
Subtotal @ base rates after application of correction factor				$ **578,248**		$ **619,885**
Fuel Adjustment Clause - proforma for rollin				(6,274)		(6,274)
Merger Surcredit				(15,832)		(15,832)
Value Delivery Surcredit				(3,492)		(3,492)
VDT Amortization & Surcredit Adjustment				41		41
Adjustment to Reflect Year-End Customers		119,502		5,808		6,245
TOTAL TRAFFIC LIGHTING ENERGY RATE TLE				$ **558,499**		$ **600,573**
PROPOSED INCREASE						$ **42,075**
Percentage Increase						7.53%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roil-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
PUBLIC STREET LIGHTING RATE PSL					
	Lights				
OVERHEAD SERVICE					
Mercury Vapor - Installed prior to January 1, 1991					
100 Wall	564	$6.08	$ 3,429	$ 6.52	$ 3.677
175 Wall	35.831	$7.08	253,083	$ 7.59	271.957
250 Wall	58.512	$8.03	469,851	$ 8.81	503.788
400 **Wall**	85.032	$9.56	812.906	$ 10.25	871.578
400 Walt (metal pole)		$13.90		$ 14.90	
1000 Wan	168	$17.64	2.964	$ 18.92	3.179
Mercury Vapor- Installed after December 31. 1990					
100 wan					
175 Wall	24	$ 8.81	211	$ 9.45	227
250 Wall	631	$ 9.86	6.222	$ 10.57	8,670
400 Wall	204	$ 11.60	2,407	$ 12.85	2.581
400 Wall (metal pole)					
1000 Wan	96	$ 21.24	2.039	$ 22.78	2.187
Sodium Vapor - Installed prior to January 1.1991					
100 wan	216	$7.27	1,570	$ 7.80	1.885
150 Watt	23,400	$8.89	203,346	$ 9.32	218,088
250 **Walt**	26.448	$10.37	274,268	$ 11.12	294.102
400 Wall	54,105	$10.72	580,008	$ 11.49	621.666
1000wan					
Sodium Vapor - Installed after December 31,1990					
100 **Watt**	4,290	$ 7.27	31,188	$ 7.80	33,462
150 Wall	6.347	$ 6.69	55.155	$ 9.32	59,154
250 Wall	840	$ 10.37	8,711	$ 11.12	9,341
400 wan	22.793	$ 10.72	244.341	$ 11.49	261,892
1000 **Watt**	24	$ 24.37	585	$ 28.13	627

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rater	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
PUBLIC STREET LIGHTING RATE PSL (continued)					
	Lights				
UNDERGROUND SERVICE					
Mercury Vapor- Installed prior to January 1, 1991					
100 Watt **Top** Mounted	1,200	$ 9.98	11.952	$ 10.68	12,816
175 Watt **Top** Mounted	12.888	$ 10.86	139.984	$ 11.65	150.145
175 Watt	1,236	$ 14.77	18.256	$ 15.84	19,578
250 Wan	12,120	$ 15.78	191,011	$ 16.90	204.828
400 Wan	8.364	$ 18.49	154,650	$ 19.83	165.858
400 Wan **(metal pole)**	4.452	5 18.49	82.317	$ 19.83	88.283
Mercury Vapor - Installed after December 31. 1990					
100 Wan **Top** Mounted		$ 12.30		5 13.19	
175 Watt **Top** Mounted	444	$ 13.32	5.914	$ 14.28	6,340
175 Watt		5 21.04		$ 22.56	
250 **Watt**	300	$ 22.08	8.624	$ 23.68	7.104
400 Wall		$ 24.02		$ 25.76	
400 Watt **(metal pole)**		$ 24.02		$ 25.76	
Sodium Vapor - **Installed** prior to January 1, 1991					
70 Walt **Top** Mounted				$	
100 Watt **Top Mounted**	23.244	5 10.94	254.289	$ 11.73	272.652
150 **Watt Top** Mounted				$	
150 wan	2,340	5 18.96	44,366	$ 20.33	47.572
250 Wall	6,744	$ 20.06	135,285	$ 21.51	145,063
250 Wall (metal **pale)**	1.344	$ 20.06	26,981	5 21.51	28,909
400 Watt	7.404	$ 21.42	158.594	$ 22.97	170,070
400 Wan (metal **pole)**	2.160	5 21.42	46.267	$ 22.97	49.615
1000 Watt					
Sodium Vapor. installed **after December** 31, 1990					
70 Watt **Top** Mounted	2,316	$ 10.55	24.434	$ 11.31	26,194
100 Watt **Top** Mounted	58.564	$ 10.94	640,690	$ 11.73	688,956
150 Watt **Top** Mounted	4.124	$ 16.18	66.726	$ 17.35	71,551
150 watt	1.125	$ 18.96	21,330	$ 20.33	22,871
250 Watt	444	$ 20.06	8,907	$ 21.51	9,550
250 Watt (metal **pale)**		5 20.06		$ 21.51	
400 Watt	2,936	$ 21.42	62,889	$ 22.97	67.440
400 Wan **(metal** pole)	12	$ 21.42	257	5 22.97	276
1000 Watt	24	$ 49.85	1,196	$ 53.45	1,283

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Rail-in Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
PUBLIC STREET UGHTING RATE PSL (continued)									
DECORATIVE UGHTING FIXTURES									
installed after December 31, 1990	*Lights*								
Acorn w/decorative baskets									
70 Watt Sodium Vapor	132	$	14.57		1.923	5	15.62		2,062
100 Watt Sodium Vapor	1,044	$	15.15		15.817	$	16.25		16,965
8-Sided Coach									
70 Watt Sodium Vapor	432	I	14.76		6,316	$	15.83		6.839
100 Watt Sodium Vapor		5	15.33			I	16.44		
Poles	*Poles*								
10ft Smooth	569	5	8.73		4.970	$	9.36		5,328
10ft Fluted	702	$	10.42		7.312	$	11.17		7.838
Bases	*Bases*								
Old Town/Manchester	115	$	2.80		322	$	3.00		345
Cheaspeak/Franklin	233	5	3.00		700	$	3.22		751
Jefferson/Winchester	710	5	3.03		2.151	5	3.25		2.307
Norfolk/Essex	142	$	3.19		453	I	3.42		486
Subtotal @ base rates before application of Correction factoi				$	5,095,104			$	5,463,137
Correction Factor -			0.997825				0.997825		
Subtotal @ base rates after application of correction factor				$	5,106,893			$	5,415,640
Fuel Adjustment Clause - proforma for rollin					(28.056)				(28.056)
Merger Surcredit					(140.918)				(140.918)
Value Delivery Surcredit					(31.091)				(31,091)
VDT Amortization & Surcredit Adjustment					364				364
Adjustment to Reflect Year-End Customers	24				2,999				3,225
TOTAL PUBLIC STREET LIGHTING RATE PSL				$	4,910,190			$	5,279,170
PROPOSED INCREASE								$	368,901
Percentage increase									7.51%

LG&E Electric Exhibit 1
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LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC PATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
OUTDOOR LIGHTING SERVICE RATE OL									
	Lights								
OVERHEAD SERVICE									
Mercury Vapor - Installed prior to January 1, 1991									
100 Wall	728	$	6.78	$	4,936	$	7.27	$	5.293
175 Wan	39.923	$	7.63		304,612	$	8.18		326,570
250 Wall	19.562	$	8.63		168,820	$	9.25		180,949
400 Wall	21.141	$	10.44		220.712	$	11.19		236,568
1000 Watt	4,443	$	18.93		84.106	$	20.30		90,193
Sodium Vapor. Installed prior To January 1, 1991									
100 wan	2,836	$	7.53		21,355	$	8.07		22.887
150 wan	7,820	$	9.82		75,228	$	10.32		80,702
250 Watt	4.927	$	11.32		55,774	$	12.14		59,814
400 Wan	50.448	$	11.89		599,627	$	12.75		643.212
1000 Watt									
	Poles								
Pole Charges	56.430	$	1.66		93.674	$	1.78		100,445
	Lights								
UNDERGROUND SERVICE									
Mercury Vapor. Installed prior Io January 1, 1991									
100 Wall Top Mounted	516	$	11.84		6,109	$	12.70		6,553
175 Watt Top Mounted	6,781	$	12.57		85,237	$	13.48		91,408
Sodium Vapor. Installed prior to January 1, 1991									
70 Wall Top Mounted		$	10.55			$	11.31		
100 Watt Top Mounted	15.235	$	13.93		212.224	$	14.94		227,611
150 Watt Top Mounted									
150 Wan		$	18.98			$	20.35		
250 Watt	384	$	21.72		8,340	$	23.29		8.943
400 Watt	509	$	23.85		12,140	$	25.57		13.015
1000 Wall									

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
OUTDOOR LIGHTING SERVICE RATE OL (continued)							
OVERHEAD SERVICE							
Mercury Vapor- Installed after December 31. 1990							
100 watt							
175 Watt	1.127	5	8.99	10,132	$	9.64	10.664
250 Watt	733	$	10.04	7,359	5	10.77	7,894
400 Walt	2,232	$	11.98	28,739	5	12.85	28,681
1000 watt	4,756	$	21.50	102,254	$	23.05	109,626
Sodium Vapor - Installed **after December** 31. 1990							
100 watt	23,025	5	7.53	173.378	5	8.07	185,612
150 wan	19,460	$	9.62	187.205	5	10.32	200.827
250 Watt	4,986	$	11.32	55.442	$	12.14	60,530
400 Wall	107.923	$	11.89	1,283,204	$	12.75	1,376,018
1000 watt	154	5	28.16	4,337	$	30.20	4,651
	Poles						
Pole Charges	46.247	$	1.66	76,770	$	1.78	62,320
UNDERGROUND SERVICE							
Mercury Vapor. Installed after December 31.1990							
100 Wan Top **Mounted**		$	12.57		$	13.48	
175 Wall **Top Mounted**	2.600	$	13.51	35.126	5	14.49	37,874
Sodium Vapor. Installed after December 31. 1990							
70 Watt Top **Mounted**	14,991	5	10.55	158.155	$	11.31	189.546
100 Watt **Top Mounted**	95.063	$	13.93	1,324,228	$	14.94	1,420,241
150 Walt **Top Mounted**	9.267	$	18.89	156,520	$	18.11	167,825
150 Watt	5.145	$	18.98	97.652	$	20.35	104,701
250 wan	5.605	$	21.72	121,741	5	23.29	130,540
400 Watt	16,237	$	23.85	387.252	$	25.57	415.180
1000 watt	286	5	53.63	15.338	$	57.51	16,448

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT **RATES** REVISED TO INCLUDE JANUARY **2004** ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rater
OUTDOOR LIGHTING SERVICE RATE OL (continued)									
DECORATIVE LIGHTING FIXTURES									
Installed after December 31.1990	*Lights*								
Acorn w/decorative baskets									
70 Walt Sodium Vapor	243	$	14.95		3.633	I	16.03		3,895
100 Watt Sodium Vapor	1.668	$	15.64		26.088	$	16.77		27,972
8-Sided Coach									
70 Watt Sodium Vapor	869	$	15.12		13.442	I	16.21		14.411
100 Watt Sodium Vapor	336	$	15.61		5.312	$	16.95		5,695
Poles	*Poles*								
10ft Smooth	1.392	$	6.73		12.152	$	9.36		13,029
10ft Fluted	1.716	I	10.42		17.880	$	11.17		19,167
Bases	*Bases*								
Old Town/Manchester	297	I	2.80		832	S	3.00		892
Cheaspeak/Franklin	603	$	3.00		1,809	$	3.22		1,942
Jefferson/Winchester	1,836	I	3.03		5,562	$	3.25		5,968
Norfolk/Essex	367	I	3.19		1,171	$	3.42		1,256
Subtotal @ bass rates before application of correction factor				$	6,264,808			$	6,717,769
Correction Factor.			0.996100				0.996100		
Subtotal @ bass **rates** after application **of** correction factor				$	8,289,337			$	6,744,072
Fuel Adjustment Clause - proforma for rollin					(29,131)				(29,131)
Merger Surcredit					(172,037)				(172,037)
Value Delivery Surcredit					(38,768)				(38,766)
VDT Amortization & Surcredit Adjustment					453				453
Adjustment to Reflect Year-End **Customers**	115				17.114				18,401
TOTAL OUTDOOR LIGHTING RATE OL				$	6,066,969			$	6,522,990
PROPOSED INCREASE								$	456,021
Percentage Increase									7.52%

Louisville Gas and Electric Company
Summary of Settlement Gas Rate increase by Rate Class
Based on Adjusted Sales and Transportation
For the 12 months Ended September 30, 2003

	Adjusted Billings at Current Rates	Proposed increase In Revenue As Filed	Percentage Increase	increase Per Proposed Settlement	Percentage increase	Percentage of Total
Residential Gas Service Rate RGS	$ 226,193,722	$ 17,187,887	7.60%	$ 9,782,051	4.32%	83.01%
Firm Commercial Gas Service Rate CGS	103,596,812	1,593,870	1.54%	1,774,266	1.71%	15.06%
Firm Industrial Gas Service Rate IGS	11,973,655	198.751	1.66%	218,727	1.83%	1.86%
As Available Gas Service Rate AAGS	3,005,383	6	0.00%	8.553	0.28%	0.07%
Firm Transportation Service Rate FT	3,939,208		0.00%		0.00%	0.00%
Pooling Service Rate PS-FT	60,600		0.00%		0.00%	0.00%
Special Contracts	1,681,970		0.00%		0.00%	0.00%
Off-System Sales	-	-		.		
Total Sales and Transportation	350,451,351	18,980,514	5.42%	11,783,597	3.36%	100.00%
Forfeited Discounts	1,264,157					
Reconnection Charges	49,349	12,006		4,002		
Meter Test Charge		31,464		31,464		
Thlrd Trlp inspection Charges	3,105	80.730		80.730		
Other Miscellaneous Revenues	591,441					
Total Revenue	$ 352,359,402	$ 19,104,714	5.42%	$ 11,899,793	3.38%	

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF SETTLEMENT GAS RATE INCREASE BY RATE CLASS
BASED ON ADJUSTED SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

REVENUE	(1) Booked Revenue Adjusted to As Billed Basis	(2) Elimination of Gas Supply Cost Recovery (GSC) Revenues (See Exhibit 7)	(3) Elimination of Demand-Side Management (DSM) Revenues	(4) Temperature Normalization Adjustment (See Exhibit 8)	(5) Year-End Customers Adjustment (See Exhibit 9)	(6) Adjustment to Reflect Rate Switching and Plant Closings (See Exhibit 10)	(7) VDT Amortization & Surcredit Adjustment	(8) GSC @ Current Nov03-Jan04 Charges	(9) Adjusted Billings at Current Rates	(10) Proposed Increase in Revenue	(11) Percentage Increase
Residential Gas Service Rate RGS	$ 189,080,204	$ (133,698,514)	$ (1,034,237)	$ 19,079	$ 114,237	$	149,202	$ 171,563,752	$ 226,193,722	$ 9,782,051	4.32%
Firm Commercial Gas Service Rate CGS	86,731,073	(65,436,260)	(455,264)	66,427	(113,425)	8,662	68,362	82,727,197	103,596,812	1,774,266	1.71%
Firm Industrial Gas Service Rate IGS	9,878,763	(7,988,579)	-	(36,404)	18,710		7,518	10,093,647	11,973,655	218,727	1.83%
As Available Gas Service Rate AAGS	3,079,249	(2,757,374)	(4,883)	(3,938)	(986)	(63,851)	2,451	2,754,718	3,005,383	8,553	0.28%
Firm Transportation Service Rate FT	5,308,129	(1,499,335)	(21,375)	(30,424)	(75,115)	13,838	2,953	242,537	3,939,208	-	0.00%
Pooling Service Rate PS-FT	60,600								60,600	-	0.00%
Special Contracts	1,708,443			(27,762)	-		1,290		1,681,970	-	0.00%
Off-System Sales	10,242,833	(10,242,833)									
Total Sales and Transportation	$ 306,087,293	$ (221,622,896)	$ (1,515,759)	$ (13,022)	$ (56,581)	$ (41,331)	$ 231,796	$ 267,381,851	$ 350,451,351	$ 11,783,597	3.36%
Forfeited Discounts	1,264,157								1,264,157		
Reconnection Charges	49,349								49,349	4,002	
Meter Test Charge	-								-	31,464	
Third Trip Inspection Charges	3,105								3,105	80,730	
Other Miscellaneous Revenues	591,441								591,441		
Total Revenue	$ 307,995,344								$ 352,359,402	$ 11,899,793	3.38%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Residential Gas Service Rate RGS	*Customer Months*	*Per customer*		*Per Customer*	
Customer Charges:	3,332,464	$7.00	23,327,246	$8.50	28,325,944
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component:	24,301,485.5	$1,3457	32,702,509	$1.5470	37,594,390
			56,029,757		65,920,342
Residential Gas Service Rate RGS Summer A/C Rider					
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Coot Component:	94.0	$0.8457	79	$1.5470	145
Subtotal	24,301,579.5		$ 56,029,837		$ 65,920,487
Correction Factor		0.99938		0.99936	
Subtotal Rate RGS after Application of Correction Factor	24,301,579.5		$ 56,065,875		$ 65,962,888
Value Delivery Surcredit			(795,671)		(795,671)
VDT Amortization 8 Surcredit Adjustment			149,202		149,202
Temperature Normalization Adjustment	(671,526.1)	$1.3457	(903,673)	$1.5470	(1,038,851)
Adjustment to Reflect Year-End Customers	48,936.3		114,237		134,453
GSC at Current (Nov03-Jan04) Charges. GSCC	23,678,989.7	$ 7,2454	171,563,752	$ 7.2454	$ 171,563,752
Total Residential Gas Service Rate RGS	23,678,989.7		$ 226,193,723		$ 235,975,773
Proposed Increase in Revenue					$9,782,051
					4.32%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated RY at Proposed Rates
Firm Commercial Gas Service Rate CGS	Customer Months	Per Customer		Per Customer	
Customer Charges (Meters < 5000 cf/hr)	281,590	$16.50	4,646,235	$16.50	4,646,235
Customer Charges (Meters >= 5000 cf/hr)	11,489	$117.00	1,344,213	$117.00	1,344,213
	293,079				
	MCF	Per Mcf		Per Mcf	
Distribution Cost Component:					
On Peak Mcf	10,842,797.2	$1.3457	14,591,152	$1.4968	16,229,499
Off Peak Mcf	877,844.1	$0.8457	742,393	$0 9968	876.035
	11,720,641.3		21,323,993		23,094,962
Gas Transportation Service/Standby Rider to Rate CGS	Customer Months	Per customer		Per Customer	
Administrative Charges:	24	$90.00	2,160	$90.00	2,160
	MCF	Pet Mcf		Per Mcf	
Distribution Cost Component:					
On Peak M d	88,084.0	$1.3457	118.535	$1,4968	131,644
Off Peak Mcf	17,767.4	$0.8457	15,026	$0.9968	17,711
	105,851.I		135,721		151,715
Firm Commercial Gas Service Rate CGS Summer A/C Rider	MCF	Per Mcf		Per Mcf	
Distribution Cast Component:	40,2540	$0.8457	34,043	$1.4966	60.252
Subtotal	11,866,746.7	1	21,493,156	$	23,306,949
Correction Factor		0.99129		0.99129	
Subtotal Rate CGS after Application of Correction Factor	11,866,746.7		$21,682,647		123.511,114
Value Delivery Surcredit			(364,672)		(364.672)
VDT Amortization & Surcredit Adjustment			68.382		88.382
Temperature Normalization Adjustment	(306,160.2)	$1,3457	(412.0001	$1.4966	(456,261)
Adjustment to Reflect Year-End Customers	(81,647.3)		(113,4251		(122,932)
Adjustment for Rate Switching & Plant Closings: Customer Chgs.	12	$117.00	1,404	$117.00	1.404
Distribution Chgs. - On-Peak	4,407.5	$1.3457	5,931	$1.4968	8,597
Distribution Chgs. - Off-Peak	1,592.0	$0.6457	1,346	$0.9968	1,567
GSC at Current (Nov03-Jan04) Charges - GSCC	11,402,368.1	$ 7.2454	82,614,718		82,614,718
GSC at Current Charges - Pipeline Supplier Demand Component	102,570.6	1 1.0966	112,479		112,479
Total Commercial Gar Service Rate CGS	11,504,938.7		$103,596,811		$105,311,071
Proposed Increase in Revenue					$1,774,266
					1.71%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

	Billing Determinants		Present Rates	Calculated Revenue at Present Rates	Settlement Rates		Calculated Revenue at Proposed Rates
Firm Industrial Gas Service Rate IGS	*Customer Months*		*Per Customer*		Per *Customer*		
Customer Charges (Meters < 5000 cf/hr)	1,463		$16.50	24,140	$16.50		24,140
Customer Charges (Meters >= 5000 cf/hr)	1,245		$1 17.00	145,665	$117.00		145.665
	MCF		*Per Mcf*		*Per Mcf*		
Distribution Cost Component:							
On Peak Mcf	1,002,298.3		$1.3457	1,346,793	$1.4966		1,500,240
Off Peak M d	401,064.1		$0.6457	339,160	$0.9966		399,761
	1,403,362.4			1,657,777			2,069,825
GasTransportation Service/Standby Rider lo Rate IGS	*Customer Months*		*Per Customer*		*Per Customer*		
Administrative Charges:	25		$90.00	2,250	$90.00		2.250
	MCF		*Per Mcf*		*Per Mcf*		
Distribution *Cod* Componenl:							
On Peak Mcf	7,600.3		$1,3457	10,226	$1.4966		11.376
Off Peak Mcf	11,340.7		$0.8457	9,591	$0.9966		11,304
	16,9410			22.069			24.931
Subtotal	1,422,303.4			$ 1,879,846		$	2,094,756
Correction Factor			0.97367		0.97367		
Subtotal Rate IGS after Application of Correction Factor	1,422,303.4			$ 1,930,275		$	2,150,950
Value Delivery Surcredit				(40,091)			(40,091)
VDT Amortization & Surcredit Adjustment				7,516			7.516
Rate Switching / Plant Closings Adjustment							
Customer Chgs			$117.00		$117.00		
On Peak *Md*			$1.3457		$1.4968		
Off Peak M d			$0.8457		$0.9968		
Temperature Normalization Adjustment	(27,0520)		$1.3457	(36,404)	$1.4966		(40,491)
Adjustment lo Reflect Year-End Customers	13.764			16.710			20,650
GSC at Current (Nov03-Jan04) Charges - GSCC	1,390,271.1	$	7 2454	10,073,070			10,073,070
GSC at Current Charges - Pipeline Supplier Demand Component	18,764.3	$	1.0966	20,577			20.577
Total Industrial Gas Service Rate IGS	1,409,035.4			$ 11,973,655		$	12,192,382
Proposed Increase In Revenue							$218.727
							1.83%

LG&E Gas Exhibit 1
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LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

			Billing Determinants		Present Rates	Calculated Revenue at Present Rates		Settlement Rates	Calculated Revenue at Proposed Rates
As Available Gas Service Rate AAGS									
Customers Currently Taking									
Service Under Rate G-6 and G-6/TS			*Customer Months*		*Per Customer*			*Per Customer*	
Customer Charges:	G-6		181		$150.00	27,150		$150.00	27,150
Administrative Charges:	G-6/TS		36		$90.00	3,240		$90.00	3,240
			217			30,390			30,390
			MCF		*Per Mcf*			*Per Mcf*	
Distribution Cost Component:									
	G-6		212,614.6		$0.6855	145,747		$0.5252	111,665
	G-6/TS		58,991.2		$0.6855	40,438		$0.5252	30,982
Subtotal			271,605.8			216,576			173,037
Customers Currently Taking									
Service Under Rate G-7		*Minimum Bills*	*Customer Months*		*Per Minimum*			*Per Customer*	
Minimum Bills		13	144		$500.00	6,500		$150.00	21,600
			MCF		*Per Mcf*			*Per Mcf*	
Distribution Cost Component			249,255.8		$0.4300	107,180		$0.5252	130,909
Subtotal			249,255.8			113,680			152,509
Subtotal Rate AAGS			520,861 6	$		330,256	$		325,547
Correction Factor					1.000583			1.000583	
Total Rate AAGS after Application of Correction Factor			520,861.6	$		330,063	$		325,357
Value Delivery Surcredit - G6						(6,580)			(6,580)
VDT Amortization & Surcredit Adjustment - G6						1,234			1,234
Value Delivery Surcredit - G7						(6,492)			(6,492)
VDT Amortization & Surcredit Adjustment - G7						1,217			1,217
Temperature Normalization Adjustment - G6			(2,467.9)		$0.6855	(1,692)		$0.5252	(1,296)
Temperature Normalization Adjustment - G7			(5,226.3)		$0.4300	(2,247)		$0.5252	(2,745)
Adjustment to Reflect Year-End Customers - G6			(1,240.3)			(988)			(790)
Adjustment to Reflect Year-End Customers - G7			-						
Adjustment for G6 Rate Switching & Plant Closings:	Customer Chgs.		(36)		0150.00	(5,400)		$150.00	(5,400)
	Administrative Chgs.		(24)		$90.00	(2,160)		69000	(2,160)
	Distribution Chgs.		(82,116.8)		$0.6855	(56,291)		$0.5252	(43,128)
GSC at Current (Nov03-Jan04) Charges - GSCC			371,355.1	$	7.2454	2,690,616			2,690616
GSC at Current Charges - Pipeline Supplier Demand Component			58,455.2	$	1.0966	64,102			64,102
Total As Available Gas Service Rate AAGS			429,810.2	$		3,005,383	$		3,013,936
Proposed Increase in Revenue									$8,553
									0.28%

LG&E Gas Exhibit 1
Page 6 of 9

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Firm Transportation Service (Non-Standby) Rate FT					
	Customer Months	*Per Customer*		*Per Customer*	
Administrative Charges:	894	$90.00	80,460	$90.00	80,460
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component	8,392,666.4	$0.4300	3,608,847	$0.4300	3,608,847
Utilization Charge for Daily Imbalances (UCDI):					
Daily Storage Charge:	*930,330.8*	$0.1200	111,640		111,640
Subtotal Rate FT	8,392,666.4		$ **3,800,946**		$ **3,800,946**
Correction Factor		0.99994			
Total Rate FT after Application of Correction Factor	8,392,666.4		$ **3,801,164**	*	**3,801,164**
Value Delivery Surcredit			(15,746)		(15,746)
VDT Amortization & Surcredit Adjustment			2,953		2,953
Adjustment for G6 Rate Switching & Plant Closings: Administrative Chgs.	12	$90.00	1,080		1,080
Distribution Chgs.	29,670.5	$0.4300	12,758		12,758
Temperature Normalization Adjustment	(70,753.1)	$0.4300	(30,424)		(30,424)
Adjustment to Reflect Year-End Customers	(167,555.0)		(75,115)		(75,115)
UCDI Charge - Daily Demand Charge (current Nov03-Jan04)	930,330.8	$ 0.2607	242,537		242,537
Total Firm Transportation (Non-Standby) Rate FT	8,154,358.3		$ **3,939,208**		$ **3,939,208**
Proposed Increase in Revenue					$ **-**
					0.00%
Pooling Service Rate PS-FT	*Customer Months*	*Per Customer*			
Pooling Charges:	808	$75.00	$60,600		$60,600
Correction Factor		1.00000			
Total Pooling Service Rate PS-FT			**$60,600**		**$60,600**
Proposed Increase in Revenue					**$0**
					0.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
[illegible]ION OI SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

		Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Special Contract		*Customer Months*	*Per Customer*		*Per Customer*	
	Customer Charges:	12	$180.00	2,160	$180.00	2,160
	Administrative Charges:	12	$90.00	1,080	$90.00	1,080
		MCF	*Per Mcf*		*Per Mcf*	
	Distribution Cost Component	1,107,542.5	$0.1049	116,181	$0.1049	116,181
	Demand Charges	112,956.9	$2.7500	310,631	$2.7500	310,631
Subtotal				$ **430,053**		$ **430,053**
	Correction Factor		0.99994		0.99994	
Subtotal After Application of Correction Factor				**430,078**		**430,078**
VDT Amortization & Surcredit Adjustment				329		329
Value Delivery Surcredit				(1,754)		(1,754)
Temperature Normalization Adjustment		(36,490.3)	$0.1049	(3,828)	$0.1049	(3,828)
Total Special Contract		1,071,052.2		$ **424,825**		$ **424,825**
	Proposed Increase in Revenue					$ **-**
						0.00%

		Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Special Contract		*Customer Months*	*Per Customer*		*Per Customer*	
	Customer Charges:	12	$180.00	2,160	$180.00	2,160
	Administrative Charges:	12	$90.00	1,080	$90.00	1,080
		MCF	*Per Mcf*		*Per Mcf*	
	Distribution Cost Component	1,324,790.6	$0.1049	138,971	$0.1049	138,971
	Demand Charges	71,028.5	$2.7500	195,328	$2.7500	195,328
Subtotal				$ **337,539**		$ **337,539**
	Correction Factor		1.00000		1.00000	
Subtotal After Application of Correction Factor				$ **337,539**		$ **337,539**
VDT Amortization & Surcredit Adjustment				263		263
Value Delivery Surcredit				(1,402)		(1,402)
Temperature Adjustment		(10,561.7)	$0.1049	(1,108)	$0.1049	(1,108)
Total Special Contract		1,314,228.9		$ **335,292**		$ **335,292**
	Proposed Increase in Revenue					$ **-**
						0.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30

	Billing Determinants		Present Rates	Calculated Revenue at Present Rates		Settlement Rates	Calculated Revenue at Proposed Rates
Special Contract	*Customer Months*		*Per Customer*			*Per Customer*	
Customer Charges:	24		$180.00	4.320		$180.00	4.320
Administrative Charges:	24		$90.00	2.160		$90.00	2,160
	MCF		Per *M d*			*Per Mcf*	
Distribution Cost Component	2,941,326.6		$0 3200	941.225		$0.3200	041.225
Subtotal			I	947.705	$		947.705
Correction Factor			*1.00000*			1.00000	
Subtotal After Application of Correction Factor			$	947.704	I		947,704
VDT Amortization & Surcredit Adjustment				698			698
Value Delivery Surcredit				(3,723)			(3,723)
Temperature Adjustment	(71,333.1)		$0.3200	(22,827)		$0.3200	(22,627)
Total Special Contract	2,869,993.5		$	921,853	$		921.853
Proposed Increase in Revenue					I		
							0.00%

Reserved Balancing Service Rate RBS

	Billing Determinants		Present Rates	Calculated Revenue at Present Rates		Settlement Rates	Calculated Revenue at Proposed Rates
	MCF		*Per Mcf*			*Per Mcf*	
Monthly Balancing Charge:		$	3.65	$0	I	3.85	$0
Monthly Demand Charge:		I	7.93	$0	I	7.93	$0
				$0			$0
Correction Factor						0	
Total after Application of Correction Factor				$0			$0
Proposed Increase in Revenue							$0
							0.00%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAY 0 4 2004

PUBLIC SERVICE

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

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO: 2003-00434

STIPULATION

WHEREAS, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") filed applications to make general adjustments to the Companies' rates, terms and conditions on December 29, 2003 in Case Nos. 2003-00433 and 2003-00434;

WHEREAS, The Kroger Co. was granted full intervention by the Kentucky Public Service Commission ("Commission") on January 22, 2004;

WHEREAS, the Companies and The Kroger Co. (the "parties") wish to facilitate the disposition of these two proceedings through the submission of a joint stipulation on revenue requirement and rate design issues; and,

NOW THEREFORE, pursuant to 807 KAR 5:001 Section 4(6) the parties stipulate as follows:

The Companies will request authority from the Commission to offer experimental time-ofday rate schedules for commercial customers whose maximum monthly demands were greater than 250 KW and less than 2,000 KW during the calendar year 2003 on a revenue-neutral basis. The experimental time-ofday rate schedules will be available to 100 accounts currently served under Rate LC by LG&E, and to 100 accounts currently served under Rate LP by KU.

2 After three years, the Companies will evaluate the performance of the experimental time-of-day rate schedules for the following purposes: (i) to determine the amount of load shifted from the on-peak period to the off-peak period, (ii) to determine the amount of revenue loss from the experimental time-of-day rate schedules, (iii) to evaluate customer acceptance of the experimental time-ofday rate schedules, and (iv) to evaluate the potential for implementing the experimental time-of-day rate schedules as either a permanent demand-side management program or as a standard rate schedule. The Companies shall file a report with the Commission describing their findings within six months after the first three years of implementation of the experimental time-of-day rate schedules. The experimental time-ofday rate schedules shall remain in effect until the rate schedules are terminated by order of the commission.

3. Any customer-specific costs of offering the experimental time-ofday rate schedules, including but not limited to the additional cost of the metering equipment, meter reading, and customer-specific billing costs, shall be recovered through a monthly facilities charge billed to the participants of the experimental time-of-day rate schedules. The monthly facilities charge shall be $15.00 per customer per month.

4. The experimental time-ofday rate schedule for customers served under LG&E's Rate LC shall include energy charges corresponding to $0.0300 per kWh during the designated

on-peak period and $0.0140 per kWh during the designated off-peak period. These charges are based on an energy charge filed by LG&E of $0.0240/kWh. Should the Commission approve an energy charge in this proceeding for Rate LC that differs from the one filed by LG&E, the on-peak and off-peak energy charges shall be adjusted pro-rata to reflect the energy charge established by the Commission. During the summer billing months of June through September, the designated on-peak period shall be: weekdays, from 10 AM. to 9 P.M. Eastern Standard Time (EST) during the four monthly billing periods of June through September. During the winter billing months of October through May, the designated on-peak period shall be: weekdays, from 8 A.M. to 10 P.M Eastern Standard Time (EST) during the eight monthly billing periods of October through May. The designated off-peak period shall be all hours not included during the summer and winter peak periods. The demand and customer charges shall be the Same as approved by the Commission for Rate. LC.

5. The experimental time-of-day rate schedule for customers served under KU's Schedule LP shall include energy charges corresponding to $0.0280 per kWh during the designated on-peak period and $0.0150 per kWh during the designated off-peak period. These charges are based on an energy charge filed by KU of $0.0220/kWh. Should the Commission approve an energy charge for Schedule LP in this proceeding that differs from the one filed by KU, the on-peak and off-peak energy charges shall be adjusted pro-rata to reflect the energy charge established by the Commission. During the summer billing months of June through September, the designated on-peak period shall be: weekdays, from 10 A.M. to 9 P.M. Eastern Standard Time (EST) during the four monthly billing periods of June through September. During the winter billing months of October through May, the designated on-peak period shall be: weekdays, from 8 A.M. to 10 P M Eastern Standard Time (EST) during the eight monthly

billing periods of October through May. The designated off-peak period shall be all hours not included during the summer and winter peak periods. The demand and customer charges shall be the same as approved by the Commission for Schedule LP.

6. The non-customer specific costs of modifying LG&E's customer billing system to bill customers under the experimental time-of-day rate schedule will be recovered through a charge per kWh billed to customers taking service under Rate LC determined in the same manner as the DSM Cost Recovery Component of LG&E's Demand-Side Management Cost Recovery Mechanism. The cost of modifying LG&E's customer billing system is estimated to be a total of $87,150, or $29,050 annually for three years. The charge would be $0.00001/kWh.

7. The non-customer specific costs of modifying KU's customer billing system to bill customers under the experimental time-of-day rate schedule will be recovered through a charge per kWh billed to customers taking service under Rate LP determined in the same manner as the DSM Cost Recovery Component of KU's Demand-Side Management Cost Recovery Mechanism. The cost of modifying KU's customer billing system is estimated to be a total of $87,150, or $29,050 annually for three years. The charge would be $0.00001/kWh.

8. LG&E will collect any revenue from lost sales from the experimental time-of-day rate schedule through a charge billed to customers taking service under Rate LC determined in the same manner as the DSM Revenue From Lost Sales Component of LG&E's Demand-Side Management Cost Recovery Mechanism. The Revenue From Lost Sales will be determined annually by comparing billings of customers taking service under the experimental time-of-day rate schedule to billings computed under Rate LC for twelve-month periods.

9. KU will collect any revenue from lost sales from the experimental time-of-day rate schedule through a charge billed to customers taking service under Rate LP determined in

the same manner as the DSM Revenue From Lost Sales Component of KU's Demand-Side Management Cost Recovery Mechanism. The Revenue From Lost Sales will be determined annually by comparing billings of customers taking service under the experimental time-of-day rate schedule to billings computed under Rate LP for twelve-month periods.

10. The experimental time-of-day rate schedules will become effective fourteen weeks after the dates of the Commission's Orders in the above-captioned proceedings.

11. The Kroger Co. shall withdraw the direct testimony submitted by Kevin C. Higgins on behalf of The Kroger Co. in Case Nos. 2003-00433 and 2003-00434 and shall not otherwise contest the Companies' proposals in Case Nos. 2003-00433 and 2003-00434 regarding the application of the Merger Surcredits, the shareholder components of the Merger Surcredits, the VDT Surcredits, the shareholder components of the VDT Surcredits, the Companies' proposed revenue increase, or the Companies' proposed allocation of the rate increase.

The parties submit the foregoing stipulation is a fair, just and reasonable resolution of the issues identified herein and request the Commission to determine the resolution of the issues herein based upon the stipulation.

Dated: May 4,2004

Respectfully submitted,

Kendrick R. Riggs
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COUNSEL FOR LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

- and -

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COUNSEL. FOR THE KROGER COMPANY

STANDARD RATE SCHEDULE STOD

Small Time of Day Rate

N

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to commercial customers whose average maximum monthly demands are greater than 250 KW and less than 2,000KW.

a) STOD shall be available as an optional pilot program for three years effective 14 weeks following the Final Order in PSC Case No 2003-00433 for existing customers on Rate LC, Original Sheet No 15, PSC of Kentucky Electric No 6.
b) As an optional pilot program, STOD is restricted to 100 customers. The Company will notify all eligible customers of STOD and accept applications on a first-come-first-served basis with the beginning of business 6 weeks following the Final Order in PSC Case No 2003-00433.
c) For each year or partial year of the pilot program, programming costs plus lost revenues will be recovered from customers served under Rate LC by a program cost recovery mechanism.
d) No customers will be accepted for STOD following the end of the second year of the pilot program.
e) The Company will file a report on STOD with the Commission within six months of the end of the third year of the pilot program. Such report will detail findings and recommendations.
f) STOD shall remain in effect until terminated by order of the Commission.

RATE

Customer Charge: $80.00 per month

Plus a Demand Charge:
Winter Rate applies to the eight consecutive billing months October through May
Secondary Service - $11.14 per KW per month
Primary Service - $ 9.52 per KW per month
Summer Rate applies to the four consecutive billing months June through September
Secondary Service - $14.20 per KW per month
Primary Service - $12.32 per KW per month

Plus an Energy Charge of:
On-Peak Energy - $0.02936 per KWH
Off-Peak Energy - $0.01370 per KWH

Where the On-Peak Energy is defined for bills rendered during a billing period as the metered consumption from:

a) 10 A.M. to 9 P.M., Eastern Standard Time, on weekdays for the four consecutive billing months of June through September or
b) 8 A.M. to 10 P.M., Eastern Standard Time, on weekdays for the eight consecutive billing months from October through May.

All other metered consumption shall be defined as Off-Peak Energy.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period: but not less than 50% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 25 kilowatts (10 kilowatts to any customer served under this rate schedule on March 1, 1964).

STANDARD RATE SCHEDULE **STOD**

Small Time of Day Rate

N

PROGRAM COST RECOVERY MECHANISM

The monthly billing amount computed under Rate LC shall be adjusted by the Program Cost Recovery Factor which shall be calculated per KWH in accordance with the following formula:

Program Cost Recovery Factor = (PC + LR) / LPKWH

Where:

a) PC is the cost of programming the billing system and will be no more than $29,050 for each of the three years of the pilot program.
b) LR is the lost revenues of the pilot program calculated by subtracting the revenues that would have been billed under Rate LC from the revenues realized by actual billings under STOD. LR will be calculated for the first program year and applied in the second program or recovery year. That procedure will repeat for each year or partial year the pilot is in effect.
c) LPKWH is the expected KWH energy sales for the LC rate in the recovery year.
d) The Company will file any change in the Program Cost Recovery Factor with supporting calculations ten days prior to application.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 70
Demand Side Management Cost Recovery Mechanism	Sheet No. 71
Environmental Cost Recovery Surcharge	Sheet No. 72
Merger Surcredit Rider	Sheet No. 73
Earnings Sharing Mechanism	Sheet No. 74
Value Delivery Surcredit Rider	Sheet No. 75
Franchise Fee Rider	Sheet No. 76
School Tax	Sheet No. 77

MINIMUM CHARGE

The bill shall in no event be less than the Customer Charge plus the Demand Charge computed upon the billing demand for the month.

LATE PAYMENT CHARGE

The bill will be rendered at the above net charges (including net minimum bills when applicable) plus an amount equivalent to 1% thereof, which amount will be deducted provided bill *is* paid within 15 days from date

EXIT AND EMERGENCY LIGHTING

Where governmental code or regulation requires a separate circuit for exit or emergency lighting, the demand and consumption of such separate circuit may be combined for billing with those of the principal light and power circuit or circuits

TERM OF CONTRACT

For a fixed term of not less than one year and for such time thereafter until terminated by either party giving 30 days written notice to the other of the desire to terminate. A customer exiting the pilot program will not be allowed to return to it until the Commission has issued a decision on the STOD program report.

STANDARD RATE SCHEDULE STOD

Small Time of Day Rate

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto

N

ELECTRIC RATE SCHEDULE STOD

Small Time-of-Day Service

APPLICABLE

In all territory sewed by the Company.

AVAILABILITY OF SERVICE

Available to commercial customers whose average maximum monthly demands are greater than 250 KW and less than 2,000KW.

a) STOD shall be available as an optional pilot program for three years effective 14 weeks following the Final Order in PSC Case No 2003-00434 for existing customers on Rate LP, Original Sheet No 20, PSC No 13.
b) As an optional pilot program, STOD is restricted to 100 customers. The Company will notify all eligible customers of STOD and accept applications on a first-come-first-served basis with the beginning of business *6* weeks following the Final Order in PSC Case No 2003-00434.
c) For each year or partial year of the pilot program, programming costs plus lost revenues will be recovered from customers served under Rate LP by a program cost recovery mechanism.
d) No customers will be accepted for STOD following the end of the second year of the pilot program.
e) The Company will file a report on STOD with the Commission within six months of the end of the third year of the pilot program. Such report will detail findings and recommendations
f) STOD shall remain in effect until terminated by order of the Commission.

RATE

Customer Charge: $90.00 per month

Plus a Demand Charge:

Secondary Service -	$6.65 per KW per month
Primary Service -	$6.26 per KW per month
Transmission Service -	$5.92 per KW per month

Plus an Energy Charge of:

On-Peak Energy -	$0.02800 per KWH
Off-Peak Energy -	$0.01500 per KWH

Where the On-Peak Energy is defined for bills rendered during a billing period as the metered consumption from:

a) 10 A.M. to 9 P.M., Eastern Standard Time, on weekdays for the four consecutive billing months of June through September or
b) 8 A.M. to 10 P.M., Eastern Standard Time, on weekdays for the eight consecutive billing months from October through May.

All other metered consumption shall be defined as Off-Peak Energy.

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average KW demand delivered to the customer during the 15-minute period of maximum use during the month.

The company reserves the right to place a KVA meter and base the billing demand on the measured KVA. The charge will be computed based on the measured KVA times 90 percent of the applicable KW charge.

ELECTRIC RATE SCHEDULE STOD

Small Time-of-Day Service

In lieu of placing a KVA meter, the Company may adjust the measured maximum load for billing purposes when power factor is less than 90 percent in accordance with the following formula:
(BASED ON POWER FACTOR MEASURED AT TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum KW Load for Billing Purposes} = \frac{\text{Maximum Load Measured} \times 90\%}{\text{Power Factor (in Percent)}}$$

PROGRAM COST RECOVERY MECHANISM

The monthly billing amount computed under Rate LP shall be adjusted by the Program Cost Recovery Factor which shall be calculated per KWH in accordance with the following formula:

$$\text{Program Cost Recovery factor} = (PC + LR) / LPKWH$$

Where:

a) PC is the cost of programming the billing system and will be no more than $29,050 for each of the three years of the pilot program.
b) LR is the lost revenues of the pilot program calculated by subtracting the revenues that would have been billed under Rate LP from the revenues realized by actual billings under STOD. LR will be calculated for the first program year and applied in the second program or recovery year. That procedure will repeat for each year or partial year the pilot is in effect.
c) LPKWH is the expected KWH energy sales for the LP rate in the recovery year.
d) The Company will file any changes to the Program Cost Recovery Factor with supporting calculations ten days prior to application.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 70
Demand Side Management Cost Recovery Mechanism	Sheet No. 71
Environmental Cost Recovery Surcharge	Sheet No. 72
Merger Surcredit Rider	Sheet No. 73
Earnings Sharing Mechanism	Sheet No. 74
Value Delivery Surcredit Rider	Sheet No. 75
Franchise Fee Rider	Sheet No. 76
School Tax	Sheet No. 77

MINIMUM CHARGE

Service under this schedule is subject to an annual minimum of $81.24 per kilowatt for secondary delivery, $77.16 per kilowatt for primary delivery and $73.08 per kilowatt for transmission delivery for each yearly period based on the greater of (a), (b), (c), (d), or (e) as follows:

(a) The highest monthly maximum load during such yearly period.
(b) The contract capacity, based on the expected maximum KW demand upon the system.
(c) 60 percent of the KW capacity of facilities specified by the customer.
(d) Secondary delivery, $812.40 per year; Primary delivery, $1,929.00 per year; Transmission delivery, $3,654.00 per year.
(e) Minimum may be adjusted where customer's service requires an abnormal investment in special facilities.

ELECTRIC RATE SCHEDULE STOD

Small Time-of-Day Service

Payments to be made monthly of not less than **1/12** of the Annual Minimum until the aggregate payments during the contract year equal the Annual Minimum. However, payments made in excess of the amount based on above rate schedule will be applied as a credit on billings for energy used during contract year. A **new** customer or an existing customer having made a permanent change in the operation of electrical equipment that materially affects the use in kilowatt-hours and/or use in kilowatts of maximum load will be given an opportunity to determine new service requirements in order to select the most favorable contract year period and rate applicable. N

DUE DATE OF BILL

Customer's payment will be due within 10 days from date of bill

TERM OF CONTRACT

For a fixed term of not less than one year and for such time thereafter until terminated by either party giving 30 days written notice to the other of the desire to terminate. A customer exiting the pilot program will not be allowed to return to it until the Commission has issued a decision on the STOD program report.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto

Case Nos. 2003-00433 and 2003-00434 – LG&E and KU
Modification of Environmental Surcharge (ECR)

<u>KU</u>

- The rate base, operating expenses, and gross proceeds from by-product and allowance sales included in KU's environmental surcharge associated with its 1994 Compliance Plan ("1994 Plan") will be included and recovered through KU's base rates.

- KU's 1994 Plan will be removed from its environmental surcharge.

- The Base Period Jurisdictional Environmental Surcharge Factor ("BESF) in KU's surcharge will be recalculated to remove the effects of KU's 1994 Plan. The calculation of the revised BESF will be included as part of the first monthly surcharge filing submitted after the removal of the 1994 Plan from the environmental surcharge.

- The costs and allowance expense associated with the sulfur dioxide ("SO_2") emission allowances received from the Owensboro Municipal Utilities will be included as a component of the environmental surcharge costs recovered as part of KU's Post-I994 Plan.

- For KU, any environmental surcharge reporting format that exclusively reports information associated with the 1994 Plan will be deleted from the monthly surcharge filing. For reporting formats presenting information associated with both the 1994 Plan and Post-I994 Plan, the 1994 Plan information will be shown as "0". Reporting formats will be renumbered to reflect the deleted reporting formats during the next surcharge review.

- KU's ES Form 2.31, of Emission Allowances – Current Vintage Year," will no r ce d with th no environmental surcharge s KU will continue t include ; Form 2.30, "Inventory of Emission All "

<u>LG&E</u>

- The rate base, rating expenses, and s proce d from allo sales uded i LG&E's l g associated with its 1995 Compliance Plan (' Plan") will be included and recovered th LG&E's base ates.

- I 995 Plan will be removed f m its environmental urcharge.

- The BESF in LG&E's surcharge will be recalculated t remove the effects of I 1995 Plan. The calculation f the revised BESF will be included as t f the first monthly surcharge filing submitted after the removal of the 1995 Plan from the environmental surcharge.

- For LG&E, any environmental surcharge reporting format that exclusively reports information associated with the 1995 Plan will be deleted from the monthly surcharge filing. For reporting formats presenting information associated with both the 1995 Plan and Post-1995 Plan, the 1995 Plan information will be shown as "0". Reporting formats will be renumbered to reflect the deleted reporting formats during the next surcharge review.

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

Determination of LG&E's Rate Base Allocation Ratio
And the Pro Forma Adjustments to LG&E's Electric Rate Base

Rate Base Allocation Ratio

The determination of LG&E's electric capitalization reflects the allocation of the total company capitalization using an allocation factor based on LG&E's actual test-year electric rate base compared to the total company rate base.

	Electric Rate Base As of 09/30/03	Total Company Rate Base As of 09/30/03
Total Utility Plant in Service	$3,232,386,289	$3,752,179,495
Add:		
Materials & Supplies	55,832,046	55,936,971
Gas Stored Underground	0	38,757,261
Prepayments	2,882,693	3,207,802
Cash Working Capital Allowance	52,800,999	58,441,691
Subtotal	$ 111,515,738	$ 156,343,725
Deduct:		
Accumulated Depreciation	1,339,452,661	1,522,825,598
Customer Advances	507,146	9,700,500
ADIT	326,087,270	384,571,974
SFAS 109 ADIT	(34,633,001)	(39,190,651)
Investment Tax Credit (prior law)	3,943	3,943
Subtotal	$1,631,418,019	$1,877,911,364
Net Original Cost Rate Base	$1,712,484,008	$2,030,611,856
Percentage of Electric Rate Base to Total Company Rate Base		84.33%

The electric and total company rate base calculations match those submitted by LG&E in Rives Direct Testimony, Rives Exhibit 3, page 1 of 2, except for the treatment of Accumulated Deferred Income Taxes ("ADIT"), which are described in the Order.

APPENDIX D (continued)

Pro Forma Adjustments to LG&E's Electric Rate Base

	Post-1995 Environmental Surcharge	E. W. Brown Improvement Reimburse.	SFAS No. 143 Adjustment	Carbide Lime Inventory	Commission Expense Adjustments	Total All Pro Forma Adjustments
Total Utility Plant in Service	(203,504,422)	(3,351,980)	(4,585,010)	0	0	(211,441,412)
Add:						
Materials & Supplies	0	0	0	(332,637)	0	(332,637)
Prepayments	0	0	0	0	0	0
Cash Working Capital	0	0	0	0	2,227,690	2,227,690
Subtotal	0	0	0	(332,637)	2,227,690	1,895,053
Deduct:						
Accumulated Depreciation	(1,973,149)	0	0	0	(580,797)	(2,553,946)
Customer Advances	0	0	0	0	0	0
ADIT	(596,849)	0	0	0	0	(596,849)
SFAS 109 ADIT	0	0	0	0	0	0
Investment Tax Credit	0	0	0	0	0	0
Subtotal	(2,569,998)	0	0	0	(580,797)	(3,150,795)
Net Adjustments	(200,934,424)	(3,351,980)	(4,585,010)	(332,637)	2,808,487	(206,395,564)

The adjustments for the Post-1995 Environmental Surcharge, E.W. Brown Improvement Reimbursement, and the SFAS No. 143 were provided by LG&E in its response to the Commission Staff's Third Data Request dated March 1, 2004, Item 39.

The Post-1995 Environmental Surcharge adjustment reflects the removal of all rate base-related components. The amounts shown about have been revised to include the ADIT associated with the Post-1995 Environmental Surcharge. When the corresponding adjustment is made to capitalization, the ADIT amount will not be included since ADIT is not funded by capitalization. This treatment is consistent with the Commission's decision in Case No. 1998-00426.

The Carbide Lime Inventory adjustment reflects the removal from Materials & Supplies of 2 months of this inventory from the 13-month average balance calculation. This is an adjustment proposed by the AG that the Commission agrees with.

The Commission Expense Adjustments reflect the calculation of the cash working capital allowance using the $1/8^{th}$ formula and the change in Operation and Maintenance Expenses and the adjustment to depreciation expense as described in the Order.

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

Determination of LG&E's Electric Capitalization

LG&E's Electric Capitalization Prior to Adjustments

	Test Year Actual Balances	Updated Capital Structure	Revised TY Actual Balances	Rate Base Allocation Percentage	Capitalization Allocated to Electric
Long-Term Debt	797,769,753	43.32%	833,718,930	84.33%	703,075,174
Short-Term Debt	75,132,051	5.26%	101,231,800	84.33%	85,368,777
Accounts Receivable Securitization	74,800,000	0.00%	0	84.33%	0
Preferred Stock	70,424,594	3.71%	71,401,136	84.33%	60,212,578
Common Equity	906,432,535	47.71%	918,207,067	84.33%	774,324,021
Totals	1,924,558,933	100.00%	1,924,558,933		1,622,980,550

LG&E's Electric Capitalization After Adjustments

	Capitalization Allocated to Electric	Net Adjustments to Electric Capitalization	Adjusted Electric Capitalization	Adjusted Capital Structure
Long-Term Debt	703,075,174	(70,810,194)	632,264,980	42.58%
Short-Term Debt	85,368,777	(8,597,914)	76,770,863	5.17%
Preferred Stock	60,212,578	(6,064,307)	54,148,271	3.65%
Common Equity	774,324,021	(52,542,669)	721,781,352	48.60%
Totals	1,622,980,550	(138,015,084)	1,484,965,466	100.00%

APPENDIX E (continued)

Adjustments to Electric Capitalization

	Long-Term Debt	Short-Term Debt	Preferred Stock	Common Equity	Total Adjustments
Trimble County Inventories	(1,282,600)	(155,736)	(109,844)	(1,412,578)	(2,960,758)
Other Investments	(212,268)	(25,774)	(18,179)	(233,779)	(490,000)
JDIC	21,426,325	2,601,627	1,834,988	23,597,643	49,460,583
E. W. Brown Improvement	(1,452,078)	(176,314)	(124,358)	(1,599,230)	(3,351,980)
Minimum Pension Liability	0	0	0	25,443,354	25,443,354
SFAS No. 143 – ARO	(1,986,226)	(241,172)	(170,104)	(2,187,508)	(4,585,010)
Post-1995 Environmental Surcharge	(87,303,347)	(10,600,545)	(7,476,810)	(96,150,571)	(201,531,273)
Totals	(70,810,194)	(8,597,914)	(6,064,307)	(52,542,669)	(138,015,084)

The Updated Capital Structure percentages were used for adjustments allocated to all components of capitalization on a pro rata basis.
The Minimum Pension Liability impacts only the Common Equity, so a pro rata allocation to all components of capitalization is not appropriate.
As noted in Appendix C, the adjustment for the Post-1995 Environmental Surcharge does not include the balance for ADIT, since ADIT is not funded by capitalization.

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

Schedule of Adjustments

The following adjustments were proposed by LG&E in its application, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
1.	Adjust mismatch in fuel recovery.	Sch. 1.01	-$4,406,145	-$2,005,300
2.	Adjust base rates and Fuel Adjustment Clause ("FAC") reflect a full year of FAC roll-in.	Sch. 1.02	+$547,244	0
3.	Adjustment to eliminate environmental surcharge revenues and expenses.	Sch. 1.03	-$11,228,429	-$1,766,344
4.	Eliminate electric brokered sales revenues and expenses.	Sch. 1.06	-$5,389,000	-$7,811,321
5.	Eliminate electric ESM revenues collected.	Sch. 1.07	-$6,974,780	0
6.	Eliminate ESM, environmental surcharge, and FAC in Rate Refund Account 449.	Sch. 1.08	-$7,150,231	0
7.	Eliminate demand-side management revenues and expenses.	Sch. 1.09	-$3,277,501	-$3,280,013
8.	Eliminate advertising expenses pursuant to 807 KAR 5:016.	Sch. 1.15	0	-$62,499
9.	Adjustment to remove One-Utility costs.	Sch. 1.18	0	-$1,061,924
10.	Adjustment for VDT net savings to shareholders.	Sch. 1.20	0	+$5,640,000
11.	Adjust VDT-related revenues and expenses to settlement agreement.	Sch. 1.21	+$44,485	-$224,718
12.	Adjustment for merger savings.	Sch. 1.22	-$2,758,795	+$19,427,401

APPENDIX F (continued)

	Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
13.	Adjustment to eliminate LG&E/KU merger amortization expense.	Sch. 1.23	0	-$2,722,005
14.	Adjustment for MISO Schedule 10 credits.	Sch. 1.24	0	+$709,577
15.	Adjust for cumulative effect of accounting change. [AG withdrew objection to adjust- ment; AG Post-Hearing Brief at 12]	Sch. 1.25	0	+$5,280,909
16.	Adjustment to remove E. W. Brown legal expenses.	Sch. 1.27	0	-$2,157,640
17.	Adjust for customer rate switching and customer plant closing.	Sch. 1.28	+$6,445	0
18.	Adjustment for corporate office lease expense.	Sch. 1.29	0	+$1,798,420
19.	Adjust for Cane Run repair refund.	Sch. 1.30	0	+$3,588,000
20.	Adjust for prior income tax true-ups and adjustments.	Sch. 1.38	0	-$58,593

The following adjustments were proposed in the application and later revised by LG&E, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Revision Reference	Change to Revenues	Change to Expenses
1.	Adjust base rate revenues to reflect a full year of the environmental surcharge roll-in. [Rives Ex. 1, Sch. 1.04]	PSC 3-35	+$717,788	0
2.	Adjust off-system sales revenues for the environmental surcharge calculations. [Rives Ex. 1, Sch. 1.05]	Seelye Rebuttal Ex. 2	-$2,925,817	0
3.	Adjustment to reflect amortization of ESM audit expenses. [Rives Ex. 1, Sch. 1.17]	Scott Rebuttal Ex. 5	0	+$63,933

EXHIBIT__(LK-PSC-13-5)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2003-00434

I N D E X

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2003-00434

O R D E R

Kentucky Utilities Company ("KU"), a wholly owned subsidiary of LG&E Energy LLC ("LG&E Energy"),[1] is an electric utility that generates, transmits, distributes, and sells electricity to approximately 478,000 consumers in all or portions of 77 counties in Kentucky.[2]

BACKGROUND

On November 24, 2003, KU filed a letter giving notice of its intent to file an application for approval of an increase in its electric rates to produce additional annual revenues of $58,254,344, an increase of 8.54 percent. On December 29, 2003, KU filed its application which included new rates to be effective January 31, 2004 and proposals to revise, add, and delete several tariffs applicable to its electric service. To determine the reasonableness of the request, the Commission suspended the proposed

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[1] LG&E Energy is a Kentucky limited liability company and is an indirect subsidiary of E.ON AG, a German multi-national energy corporation.

[2] Operating under the name of Old Dominion Power Company, KU generates, transmits, distributes, and sells electricity to approximately 29,600 consumers in 5 counties in southwestern Virginia. KU also sells wholesale electric energy to 12 municipalities.

rates for 5 months from their effective date, pursuant to KRS 278.190(2), up to and including June 30, 2004.

KU's last increase in rates was authorized in March 1983 in Case No. 8624.[3] KU was required to reduce its rates as part of a rate complaint, Case No. 1998-00474,[4] in January 2000.

The following parties requested and were granted full intervention: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); the Division of Energy ("KDOE") of the Environmental and Public Protection Cabinet; the Lexington-Fayette Urban County Government ("LFUCG"); the Kentucky Industrial Utility Customers, Inc. ("KIUC"); North American Stainless, L. P. ("NAS"); The Kroger Company ("Kroger"); the Kentucky Association for Community Action, Inc. ("KACA"); and the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC").

On January 14, 2004, the Commission issued a procedural schedule to investigate KU's rate application. The schedule provided for discovery, intervenor testimony, rebuttal testimony by KU, a public hearing, and an opportunity for the parties to file post-hearing briefs. On March 23, 2004, the AG, KDOE, KIUC, NAS, Kroger, KACA, and CAC filed their testimony. Also on March 23, 2004, the Commission granted KU's motion to consolidate into this case that portion of Case No. 2003-00396,

[3] Case No. 8624, General Adjustment of Electric Rates of Kentucky Utilities Company.

[4] Case No. 1998-00474, The Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Service.

relating to a new KU tariff for Non-Conforming Load ("NCL") customers.[5] On March 31, 2004, the Commission granted a joint motion by KU, the AG, the LFUCG, and KIUC to consolidate Case No. 2003-00335, an investigation of the Earnings Sharing Mechanism ("ESM") for KU, into this proceeding.[6] KU filed its rebuttal testimony on April 26, 2004.

On April 28, 2004, an informal conference was held with all parties to discuss procedural matters and the possible resolution of pending issues. Additional conferences were held on April 29, 2004 and May 3, 2004. The public hearing was convened on May 4, 2004,[7] at which time the parties indicated that significant progress had been made toward resolving many of the issues and they requested the hearing be delayed to allow additional discussions.[8] This request was granted and, on May 5, 2004, the parties announced a tentative agreement on two documents that resolved many of the issues. One document, titled "Settlement Agreement" ("ESM Settlement"), provided for the orderly discontinuance of the ESM. The other document, titled "Partial Settlement Agreement, Stipulation and Recommendation" ("Partial Settlement and Stipulation"), addressed all the remaining issues, including the NCL tariff, and resolved many but not all of the issues raised in KU's rate case.

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[5] Case No. 2003-00396, Tariff Filing of Kentucky Utilities Company and Louisville Gas and Electric Company for Non-Conforming Load Customers.

[6] Case No. 2003-00334, An Investigation Pursuant to KRS 278.260 of the Earnings Sharing Mechanism Tariff of Kentucky Utilities Company.

[7] For administrative efficiency, the public hearing for this case was held simultaneously with the hearing for the rate case filed by the Louisville Gas and Electric Company ("LG&E"). <u>See</u> Case No. 2003-00433, An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company.

[8] Transcript of Evidence ("T.E."), Volume I, May 4, 2004, at 36-39 and 57-60.

Because the Partial Settlement and Stipulation did not resolve the issue of the appropriate revenue increase and depreciation rates for KU's electric operations, the hearing proceeded in the afternoon of May 5, 2004 with testimony being presented by KU and the AG. The hearing on those issues concluded on May 6, 2004. The parties subsequently finalized the ESM Settlement and the Partial Settlement and Stipulation and, on May 12, 2004, they filed the final versions of both documents.[9] During that hearing, the KDOE, KIUC, NAS, Kroger, KACA, and CAC withdrew their respective prefiled testimonies and responses to data requests on those testimonies. A hearing was then held on that date to receive testimony on the reasonableness of both documents.

On June 4, 2004, KU and the AG timely filed briefs in accordance with the procedural schedule. All information requested at the public hearing has been filed and the case now stands submitted for a decision.

ESM SETTLEMENT

KU previously submitted its calendar year 2003 ESM filing pursuant to its ESM tariff and it was docketed as Case No. 2004-00070.[10] In that filing, KU calculated its

[9] The ESM Settlement is attached hereto as Appendix A and the Partial Settlement and Stipulation is attached hereto as Appendix B. Both documents are incorporated into this Order as if fully set forth herein.

[10] Case No. 2004-00070, Kentucky Utilities Company's Annual Earnings Sharing Mechanism Filing for Calendar Year 2003.

2003 ESM billing factor to be 2.367 percent for April 1, 2004 through April 30, 2004, and 2.330 percent for May 1, 2004 through March 31, 2005.[11]

Under the terms of the ESM Settlement, the parties recommend that an Order be issued in Case No. 2004-00070 approving KU's 2003 ESM billing factors as filed and authorizing KU to bill them through March 31, 2005. KU would then collect and retain all this revenue. No later than May 2005, KU is to perform a final balancing adjustment to reconcile any over- or under-collection of the 2003 ESM revenues as billed from April 2004 through March 2005. Effective July 1, 2004, the ESM will be discontinued and KU will waive its rights to make any billings or seek any collections under its ESM tariff for its operations during the first 6 months of 2004.

The Commission has reviewed the ESM Settlement and finds that it constitutes a reasonable resolution of the issues related to the continuation of KU's ESM. When the Commission offered the ESM to KU in 2000, the intent was that this alternative form of regulation would provide sufficient incentives to KU to improve its performance while reducing the business risks inherent in over- and under-earnings. The management

[11] Under the provisions of its ESM tariff, KU is required to file a determination of a balancing adjustment to the current ESM billing factor, reflecting a true-up for any over- or under-collections experienced with the previous ESM billing factor. The revision in the 2003 ESM billing factor reflects the balancing adjustment for the 2002 ESM billing factor.

audit performed for the Commission concluded,[12] and KU confirmed in its own testimony, that the ESM has not incented KU to operate any differently than it would have without an ESM. In light of these results, the termination of the ESM as currently configured is reasonable. Therefore, the Commission will approve the ESM Settlement in its entirety. An Order confirming this will be issued in Case No. 2004-00070 in the near future.

The Commission notes that the ESM Settlement provides that nothing therein will bar a party from seeking, or the Commission from reinstating, an ESM which is designed to accomplish reasonable and valid regulatory objectives. While the Commission is now approving the termination of the current ESM because it did not achieve its intended purpose, we will take this opportunity to reaffirm our support for alternative rate-making mechanisms. KU is encouraged to continue considering alternative regulation, and, if it decides to propose one in the future, it should do so after seeking input from its customer representatives.

[12] The Barrington-Wellesley Group, Inc. ("BWG") performed the ESM management audit and issued its final report on August 31, 2003. BWG determined that the ESM was an effective alternative to traditional cost of service regulation, although it did recommend some modifications to the current structure. The BWG report stated "However, it is the LG&E/KU management's position that the ESM program did not change management behavior. Management contends that LG&E and KU already had a strong continuous improvement program and that the ESM reinforced this behavior and added a regulatory mechanism for dealing with the ebb and flow of earnings over time." BWG Report at IV-1.

PARTIAL SETTLEMENT AND STIPULATION

Unanimous Provisions

The Partial Settlement and Stipulation reflects a unanimous resolution of a substantial number of the issues raised, including the revenue allocations, the rate design, and KU's proposed changes in its terms and conditions of service. The major provisions of the Partial Settlement and Stipulation for KU that have been unanimously agreed to are as follows:

- KU will establish a pilot time-of-day program for no more than 100 commercial customers with a monthly demand between 250 kW and 2,000 kW.[13]

- Future Commission Orders approving cost recovery of KU's environmental projects pursuant to KRS 278.183 will be based upon an 11.00 percent return on common equity until that return is modified by the Commission.

- All costs associated with KU's 1994 environmental compliance plan will be removed from KU's monthly environmental surcharge filings and will be recovered in KU's base rates.

- All miscellaneous charges applicable to electric operations should be approved as proposed by KU except that the Disconnect-Reconnect Charge should be $20.00 and KU's After-Hours Reconnect Charge will be withdrawn.

- The monthly KU residential customer charge should be $5.00 per month; KU's Rate GS primary should be $10.00 per month; KU's Rate GS secondary should be $10.00 per month; and all other customer charges should be implemented as proposed by KU.

- KU Rate GS will be available to electric customers with connected loads up to 500 kW.

- KU's expenditure of $1 million per year for nitrogen oxide incurred pursuant to its contract with Owensboro Municipal Utilities will be recovered through KU's environmental cost recovery filings pursuant to

[13] This reflects a stipulation agreement between KU and Kroger dated May 4, 2004 and attached to the Partial Settlement and Stipulation as Exhibit 2.

KRS 278.183. The recovery of these costs will begin in April 2005 based upon the February 2005 expense month for KU.

- KU will offer a Curtailable Service Rider ("CSR1") to current customers who meet the eligibility requirements set forth in KU's proposed CSR1, subject to specific terms and conditions.

- New customers not currently served under an existing curtailable service rider will be eligible to take curtailable service under a new curtailable service rider tariff ("CSR2") as proposed by KU, except such customers will be able to buy through a request for curtailment only after having been on the CSR2 service for 3 years with no failure to curtail when requested.

- The NCL service tariff should be renamed "large industrial-time of day" ("LI-TOD"), and the LI-TOD should be the same as the NCL tariff proposed in Case No. 2003-00396, subject to changes outlined in the Partial Settlement and Stipulation.

- Unless the Commission has already modified or terminated the Value Delivery Team ("VDT") surcredit in a subsequent rate case, 6 months prior to the expiration of the 60-month period in which the VDT surcredits are in operation, KU will file with the Commission a plan for the future rate-making treatment of the VDT surcredits, shareholder savings, amortization of VDT costs, and all other VDT-related issues. The VDT surcredit tariff will remain in effect following the 60th month until the Commission enters an Order on the future rate-making treatment.

- In conjunction with the AG, KACA, and CAC, KU will file with the Commission plans for program administration of a year-round Home Energy Assistance ("HEA") program based solely upon a 10-cent per residential meter per month charge for a period of 3 years. The HEA programs will be operated by existing social service providers with experience in operating low-income energy assistance programs, and the providers will be entitled to recover actual operating expenses up to 10 percent of total HEA funds collected. KU will be entitled to recover its one-time information technology implementation costs through its Demand-Side Management mechanism. The HEA programs to be filed will commence on October 1, 2004. The Commission's approval of the Partial Settlement and Stipulation will constitute approval of the HEA parameters as proposed, subject to further review by the Commission of additional programmatic details.

- KU will not seek approval of a prepaid metering program within the next 5 years, and any such program proposed thereafter will be subject to prior Commission approval.

Non-unanimous Provisions

The Partial Settlement and Stipulation contains additional provisions that relate to issues in the rate case that were agreed to by all parties except the AG. Consequently, the Commission cannot accept these non-unanimous provisions as resolutions of the issues covered. The non-unanimous provisions which were agreed to by KU and all intervenors except the AG are as follows:

- Effective July 1, 2004, KU's revenues should be increased by $46,100,000.

- The electric rates as set forth in Exhibit 1 to the Partial Settlement and Stipulation are the fair, just, and reasonable rates for KU and those rates should be approved by the Commission for service rendered on and after July 1, 2004.

- KU's depreciation rates should remain the same as approved in the Order of December 3, 2001 in Case No. 2001-00140,[14] until the approval by the Commission of new depreciation rates for KU. KU must seek approval by filings made in its next general rate case or June 30, 2007, whichever occurs earlier. The new depreciation filings are to be based on plant in service as of a date no earlier than 1 year prior to such filing. From and after the effective date hereof, KU will maintain its books and records so that net salvage amounts may be identified.

ANALYSIS OF THE PARTIAL SETTLEMENT AND STIPULATION

In its application, KU proposed an annual increase in its electric revenues of $58,254,344. The AG proposed an annual increase in KU's electric revenues of $2,635,000. In the Partial Settlement and Stipulation, KU and all the intervenors except

[14] Case No. 2001-00140, Application of Kentucky Utilities Company for an Order Approving Revised Depreciation Rates.

the AG agree that an annual increase in electric revenues of $46,100,000 is reasonable. Since all parties have not reached a unanimous settlement on KU's electric revenues, the Commission must consider all the record evidence on this issue, including the issue of depreciation rates, and render a decision. This decision will be based on a determination, for KU's electric operations, of its capital, rate base, operating revenues, and operating expenses as would normally be done in a rate case.

The provisions of the Partial Settlement and Stipulation that have been agreed to by all parties cover issues other than the level of KU's rates and its depreciation rates. With respect to these unanimous provisions, the Commission may accept them only after conducting an independent analysis to determine whether they are reasonable and in the public interest. The Commission will make its determination of the reasonableness of these unanimous provisions after it addresses the appropriate rate level for KU.

TEST PERIOD

KU proposes the 12-month period ending September 30, 2003 as the test period for determining the reasonableness of its proposed electric rates. The AG also utilized this 12-month period. The Commission finds it is reasonable to utilize the 12-month period ending September 30, 2003 as the test period in this proceeding. In utilizing a historic test period, the Commission has given full consideration to appropriate known and measurable changes.

RATE BASE

Jurisdictional Rate Base Ratio

KU's application proposed a test-year-end Kentucky jurisdictional rate base of $1,549,420,616.[15] The AG did not calculate a test-year-end Kentucky jurisdictional rate base. The test-year-end Kentucky jurisdictional rate base is divided by KU's test-year-end total company rate base to derive a Kentucky jurisdictional rate base ratio ("jurisdictional ratio"). This jurisdictional ratio is then applied to KU's total company capitalization to determine KU's Kentucky jurisdictional capitalization. The jurisdictional ratio uses the test-year-end rate base before recognizing rate-making adjustments applicable to the either Kentucky jurisdictional or other jurisdictional operations.[16] KU and the AG used an allocation ratio of 87.97 percent.[17]

The Commission has reviewed the calculation of the test-year-end jurisdictional rate base and agrees with the calculation, except for the treatment of accumulated deferred income taxes ("ADIT") associated with Statement of Financial Accounting Standards ("SFAS 109") No. 109. The balance for ADIT used in the determination of rate base reflects the account balances for four accounts in the Uniform System of

[15] Rives Direct Testimony, Rives Exhibit 3.

[16] KU's other jurisdictional operations reflect the Old Dominion Power Company operations in Virginia and the wholesale municipal energy sales subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

[17] Rives Direct Testimony, Rives Exhibit 3.

Accounts ("USoA"): Account Nos. 190, 281, 282, and 283.[18] Account No. 190 normally is a debit balance, while the remaining three accounts normally are credit balances. The balances in these accounts are netted together to determine the amount to be included in the rate base calculations. If the net ADIT amount is a net credit balance, it is shown in the rate base calculations as a positive deduction, while a net debit balance is shown as a negative deduction.

When KU calculated its test-year-end rate base, it reported the total net credit balance resulting from Account Nos. 190, 282, and 283 as ADIT.[19] The subaccounts making up the balances for these three accounts included SFAS 109 ADIT subaccounts.[20]

KU then reported the net balance of Account Nos. 182.3 and 254[21] as its SFAS 109 ADIT. The SFAS 109 ADIT amounts from Account Nos. 190, 282, and 283 have a

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[18] Account No. 190, Accumulated Deferred Income Taxes; Account No. 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account No. 282, Accumulated Deferred Income Taxes – Other Property; and Account No. 283, Accumulated Deferred Income Taxes – Other. The Commission notes that KU's financial statements do not show a balance for Account No. 281.

[19] Consistent with previous Commission decisions, KU also excluded ADIT associated with "below the line" items from the ADIT balance included in the rate base calculation. See Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 15(f)(1) through 15(f)(5).

[20] Response to the Commission Staff's First Data Request dated December 19, 2003, Item 13(a)(b), pages 3 and 4 of 9.

[21] Account No. 182.3, Other Regulatory Assets and Account No. 254, Other Regulatory Liabilities. The subaccount balances used in the calculation are identified as SFAS 109 taxes. For Account No. 182.3, KU used the subaccount balances for 182301 through 182304. For Account No. 254, KU used the subaccount balances for 254001 through 254004. See Response to the Commission Staff's First Data Request dated December 19, 2003, Item 13(a)(b), pages 2 and 4 of 9.

net debit balance, while the SFAS 109 amounts from Account Nos. 182.3 and 254 have a net credit balance. The erroneous inclusion of the balances from Account Nos. 182.3 and 254 has the effect of partially offsetting the SFAS 109 ADIT recorded in Account Nos. 190, 282, and 283. This results in the deductions section of the rate base being overstated and the total rate base being understated. The correct presentation of the ADIT balances is the separation of the SFAS 109 ADIT from the regular ADIT.

The Commission believes the ADIT and SFAS 109 ADIT included in the rate base calculations should reflect only the balances as recorded in Account Nos. 190, 282, and 283. The calculation of KU's test-year-end Kentucky jurisdictional and total company rate bases and the jurisdictional ratio are shown in Appendix D. Therefore, the Commission has determined that KU's jurisdictional ratio is 87.14 percent.

Pro Forma Jurisdictional Rate Base

KU calculated a pro forma Kentucky jurisdictional rate base of $1,396,102,637.[22] The AG did not calculate a pro forma rate base, but proposed that KU's total company rate base be reduced by $7,089,556.[23] KU's calculations reflected the approach utilized by the Commission in previous rate cases to determine the pro forma rate base, but did not recognize certain adjustments normally included therein.

While KU removed the utility plant, construction work in progress, and accumulated depreciation associated with its Post-1994 environmental compliance plan ("Post-1994 Plan"), it should have removed the ADIT associated with the Post-1994

[22] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 38.

[23] Majoros Direct Testimony at 6-7.

Plan. Excluding the Post-1994 Plan ADIT is consistent with the Commission's treatment of this item in Case No. 1998-00474.[24] KU should have included in its balance for accumulated depreciation its proposed increase in depreciation expense, an adjustment the Commission has consistently recognized.[25] Finally, KU should have determined its cash working capital allowance for total company purposes utilizing the 1/8th formula approach.[26]

The Commission has determined KU's pro forma Kentucky jurisdictional rate base for rate-making purposes by beginning with the test-year-end Kentucky jurisdictional rate base utilized to determine the jurisdictional ratio, and then incorporating the adjustments discussed previously in this Order. The adjustment to accumulated depreciation reflects the increase in test-year depreciation expense discussed later in this Order. The cash working capital allowance has been adjusted to reflect the accepted pro forma adjustments to operation and maintenance expenses as discussed later in this Order.[27]

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[24] Case No. 1998-00474, final Order dated January 7, 2000, at 56-58 and Appendix B, and rehearing Order dated June 1, 2000, at 2-4.

[25] See Case No. 2000-00080, The Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and to Increase Its Charges for disconnecting Service, Reconnecting Service and Returned Checks, final Order dated September 27, 2000, at 18-20.

[26] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 15(f)(6).

[27] The adjustments made to determine the pro forma electric rate base are listed in Appendix D.

Based upon the previous findings, we have determined KU's pro forma Kentucky jurisdictional rate base for rate-making purposes as of September 30, 2003 to be as follows:

Total Utility Plant in Service	$2,898,076,555
Add:	
Materials & Supplies	57,926,039
Prepayments	2,935,464
Emission Allowances	59,742
Cash Working Capital Allowance	49,853,452
Subtotal	$ 110,774,697
Deduct:	
Accumulated Depreciation	1,374,772,984
Customer Advances	1,455,980
Accumulated Deferred Income Taxes	244,469,347
SFAS 109 Accumulated Deferred Income Taxes	(17,891,956)
Investment Tax Credit (prior law)	5,453,260
Subtotal	$1,608,259,615
Pro Forma Electric Rate Base	$1,400,591,637

Reproduction Cost Rate Base

KU presented a total company reproduction cost rate base of $3,160,720,995, and a Kentucky jurisdictional reproduction cost rate base of $2,752,873,919.[28] The costs were determined principally by indexing the surviving plant and equity using the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price Index.[29] The Commission has given consideration to the proposed reproduction cost rate base, but finds that using KU's historic cost for rate base is appropriate and consistent with precedents for KU and other utilities in Kentucky.

[28] Rives Direct Testimony, Rives Exhibit 4.

[29] Rives Direct Testimony at 24.

CAPITALIZATION

KU proposed an adjusted Kentucky jurisdictional capitalization of \$1,318,124,983.[30] Included in its capitalization were adjustments for the removal of undistributed subsidiary earnings, the investment in Electric Energy, Inc., the removal of other investments, the removal of reimbursed capital invested to repair the combustion turbines at the E. W. Brown Generating Station, the retirement of the Green River Units 1 and 2, the removal of KU's Post-1994 environmental compliance plan investments, and to reverse KU's minimum pension liability adjustment to Other Comprehensive Income. KU allocated the removal of undistributed subsidiary earnings and the minimum pension liability adjustments to common equity only, while it allocated all the other proposed adjustments on a pro rata basis to all components of capitalization.

The AG proposed an adjusted Kentucky jurisdictional capitalization of \$1,307,662,608.[31] The AG agreed with all of KU's adjustments to capitalization except the adjustment for the minimum pension liability. Both KU and the AG determined the Kentucky jurisdictional capitalization by multiplying KU's total company capitalization by the jurisdictional ratio described above. This is consistent with the approach used by the Commission in previous KU rate cases.

Minimum Pension Liability

KU adopted SFAS No. 130, *Reporting Comprehensive Income*, on January 1, 1998. SFAS No. 130 requires a company to report a measure of all changes in equity, not just resulting from transactions and economic events currently reflected in the

[30] Rives Direct Testimony, Rives Exhibit 2.

[31] Majoros Revenue Requirements Direct Testimony, Exhibit MJM-3.

determination of net income. The changes that are not currently reflected in net income are called Other Comprehensive Income items. Other Comprehensive Income items include foreign currency translation changes, unrealized holding gains and losses on available-for-sale securities, mark-to-mark gains and losses on cash flow hedges, and minimum pension liability. For each of these items, the liability is fully recognized on the balance sheet but not yet on the income statement, because the financial impact that unrealized changes in value may eventually cause have not occurred and have not been included in the income statement under generally accepted accounting principles.[32] A minimum pension liability occurs when, as of a measurement date,[33] the discounted benefits previously earned by participants in the pension plan exceed the market value of the pension trust assets, thus representing an unfunded pension benefit earned by plan participants to date.

For calendar year 2002, due to the below-average performance of the stock market and low interest rates, KU determined it had a total company minimum pension liability of $10,462,375.[34] KU recorded the $10,462,375 as a component of its Other Comprehensive Income and reduced its equity accordingly. KU argued that it would be an unfair regulatory policy to reduce common equity today for a loss not yet recorded on the income statement, and a loss that may or may not actually be incurred.[35] In its

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[32] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 15(c)(3), page 8 of 16.

[33] The measurement date is normally the last day of a calendar year.

[34] Rives Direct Testimony, Rives Exhibit 2.

[35] Rives Direct Testimony at 21.

application, KU requested that it be permitted to reverse the entry for the minimum pension liability and record a regulatory asset to effect the reversal. The minimum pension liability is recalculated every year and, consequently, the regulatory asset would be revised and adjusted annually. Because of this feature, KU contended that the regulatory asset would not have to be amortized.

The AG opposed the proposed adjustment citing three reasons. First, the AG contended that the equity adjustment had actually been made and was an actual known and measurable adjustment to capitalization. Because of this fact, the AG believed that reversing the write-down was not consistent with previous Commission decisions. Second, the AG did not believe the creation of the regulatory asset as proposed by KU was consistent with or allowed by SFAS No. 71. The AG believes that regulatory assets established under SFAS No. 71 are recovered through amortization of the asset to the income statement, while the proposed regulatory asset for the minimum pension liability would be extinguished through balance sheet accounting. Lastly, the AG expressed concern that the establishment of the regulatory asset for the minimum pension liability would result in a presumption that the underlying costs are recoverable from ratepayers in the future and any prudence review of those costs in the future would be precluded.[36]

KU disagreed with the AG's arguments, noting that the write-down is not a permanent adjustment to its equity balance since the minimum pension liability will change with each measurement date. KU argued that the AG's reliance on the Commission's decision in Case No. 1998-00474 had no bearing on how the reversal of the write-down for the minimum pension liability should be treated. As to establishing a

[36] Majoros Revenue Requirements Direct Testimony at 4-6.

regulatory asset under SFAS No. 71, KU stated that FERC has issued an accounting decision permitting the establishment of the minimum pension liability regulatory asset for utilities with cost based regulated rates.[37] KU dismissed the AG's concern that the creation of the regulatory asset would preclude a prudence review of pension costs in the future, noting that KU had not asserted such a claim and that the AG's witness had agreed that the FERC decision letter had eliminated the prudence concern.[38]

The Commission has not previously addressed this issue. The accounting treatment for the minimum pension liability is in effect a means of disclosing a contingency, since there is no corresponding change in the company's current pension expense recognized in the income statement. The minimum pension liability required by SFAS No. 130 and the proposed regulatory asset are unique, in that the balance is determined periodically and the recorded liability and proposed asset are adjusted accordingly. In the event the market value of the pension trust assets exceed the discounted benefits previously earned by participants in the pension plan, there would be no minimum pension liability and no corresponding adjustment to the company's equity.

The Commission finds KU's adjustments to be reasonable. The write-down of KU's equity due to the minimum pension liability is not a permanent event, with the

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[37] Rives Rebuttal Testimony at 8. In a request dated October 31, 2003, the Edison Electric Institute filed a request with FERC seeking an accounting ruling supporting the creation of a regulatory asset for those utilities required to recognize a minimum pension liability as part of the determination of Other Comprehensive Income. On March 29, 2004, FERC's Deputy Executive Director and Chief Accountant issued a decision in FERC Docket No. AI04-2-000 allowing for the creation of the regulatory asset for accounting purposes. See Rives Rebuttal Testimony, SBR Rebuttal Exhibit 1.

[38] Joint Post-Hearing Brief of LG&E and KU at 27.

adjustment recalculated at the measurement date of the pension plan. Consequently, this adjustment to equity is not the same as the adjustment cited by the AG from Case No. 1998-00474. The accounting decision issued by FERC addresses the AG's concerns regarding the legitimacy of creating the regulatory asset, and that the regulatory asset will not be amortized and recognized as a current operating expense.[39] Lastly, the Commission stresses that establishing this regulatory asset creates no presumption that the underlying pension costs are either reasonable or recoverable from ratepayers in the future.

Based upon these findings, KU's proposal is accepted and the equity in its total company capitalization is increased by $10,462,375.

<u>SFAS No. 143 – Asset Retirement Obligation ("ARO") Adjustment</u>

KU adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003. Under SFAS No. 143, if a utility determines it has a legally enforceable ARO, the utility must measure and record the liability for the ARO on its books. The liability must be recorded at fair market value in the period that the liability is incurred. A corresponding and equivalent ARO asset is also recorded on the utility's books to recognize the cost of removal as an integral part of the cost of the associated tangible asset. Utilities are also required to recognize the cumulative effect impact on their financial statements resulting from the adoption of SFAS No. 143. The cumulative effect impact represents the ARO asset depreciation and ARO liability accretion that would have been recorded had the asset and liability been recorded when the original

[39] The Commission notes that the FERC accounting decision was issued after the AG had filed his direct testimony in this case.

asset was placed into service. On April 9, 2003, FERC issued Order No. 631,[40] which generally adopted the requirements of SFAS No. 143.

In Case No. 2003-00427,[41] KU sought approval of an accounting adjustment to its ESM for calendar year 2003 to reflect its adoption of SFAS No. 143 in 2003. KU and KIUC, the only intervenor in that case, filed a stipulation that resolved all issues raised therein. Among other things, the stipulation provided that, "The ARO assets, related ARO asset accumulated depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143 will be excluded from rate base."[42]

Now, KU has proposed to remove the cumulative effect of the accounting change resulting from the adoption of SFAS No. 143[43] and to remove the ARO assets from the determination of its pro forma rate base.[44] However, KU did not propose any adjustment to its Kentucky jurisdictional capitalization corresponding with the rate base adjustment for the ARO asset. In order to be consistent with KU's efforts to remove the impact of the adoption of SFAS No. 143, it is necessary to exclude the ARO assets from KU's Kentucky jurisdictional capitalization. Such an adjustment is also consistent with

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[40] FERC Order No. 631 is the final rule in *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Docket No. RM02-7-000.

[41] Case No. 2003-00427, Application of Kentucky Utilities Company for an Order Approving an Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003.

[42] Case No. 2003-00427, final Order dated December 23, 2003 at 3.

[43] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.25.

[44] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 38, page 1 of 2, line 6. The adjustment to the pro forma Kentucky jurisdictional rate base was $7,408,501.

previous decisions by the Commission when items are removed from the calculation of rate base. Therefore, the Commission has reduced KU's Kentucky jurisdictional capitalization, on a pro rata basis, by $7,408,501.

Based on the findings herein, the Commission has determined that KU's test-year-end Kentucky jurisdictional capitalization should be $1,297,055,596. The calculation of the jurisdictional capitalization is shown in Appendix E.

REVENUES AND EXPENSES

For the test year, KU reported actual net operating income from Kentucky jurisdictional operations of $86,167,531.[45] KU proposed a series of adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income from Kentucky jurisdictional operations of $60,956,866.[46] The AG also proposed numerous revenue and expense adjustments, resulting in net operating income from Kentucky jurisdictional operations of $84,669,000.[47] The Commission finds that 21 of the adjustments, proposed in KU's application and accepted by the AG, are reasonable and will be accepted. During the proceeding, KU identified and corrected errors in several other adjustments originally proposed in its application. The Commission finds that three of these other adjustments, as corrected by KU and accepted by the AG, are reasonable and they will also be accepted. All of these 24 adjustments are set forth in detail in Appendix F, which is attached hereto.

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[45] Rives Direct Testimony, Rives Exhibit 1, page 1 of 3, line 1.

[46] Id., page 3 of 3, line 42.

[47] Majoros Accounting Direct Testimony, Exhibit MJM-2.

The Commission makes the following modifications to the remaining proposed adjustments:

Year-End Customer Adjustment

KU proposed to annualize its test-year revenues based on the number of customers served at test-year-end. Its adjustment was based on a comparison of the number of customers at year end to the 12-month average for the test year for each customer class. It proposed a corresponding electric expense adjustment, based on an operating ratio of 60.28 percent of the revenue adjustment, to reflect the related increase in variable operating expenses. KU's proposed adjustment increased revenues by $251,167 and expenses by $151,410.

Although the Commission strives for consistency on these issues, we recognize that we have accepted different methodologies to calculate customer growth adjustments in prior rate cases.[48] In some of those cases, adjustments were accepted based on a 12-month average, as KU has proposed here, and in other cases adjustments were accepted based on a 13-month average. The accepted adjustments may have been based on proposals by the utilities or the intervenors, or derived by the Commission from the record.

This record here includes KU's original calculation based on a 12-month average, as well as a revision based on a 13-month average provided in response to

[48] See Case No. 1990-00158, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, final Order dated December 21, 1990 at 40; Case No. 1998-00455, Application of Grayson Rural Electric Cooperative Corporation for an Adjustment of Rates, final Order dated July 8, 1999, at 4; and Case No. 2000-00373, The Application of Jackson Energy Cooperative Corporation for an Adjustment of Rates, final Order dated May 21, 2001, at 11-12.

discovery.[49] The Commission finds that using a 13-month average to calculate the customer growth adjustment is more appropriate than the 12-month average proposed by KU. A 13-month average, which includes the last month immediately prior to the first month of a test year, better recognizes the number, or balance, of an item as of the beginning of the test year. This approach is used to derive average balances in other areas, such as materials and supplies, prepayments, and fuel inventories.

For these reasons, the Commission will accept the adjustment based on a 13-month average, as filed in KU's data response. The result is an increase in electric revenues of $556,927 and an increase in operating expenses of $335,731. These amounts will be recognized in determining KU's revenue requirements.

Depreciation Expense

KU proposed to increase its jurisdictional depreciation expense $2,091,278 over its test-year actual level. This increase was based on its plant balances as of September 30, 2003, and the application of new depreciation rates as proposed in this proceeding. KU's new depreciation study was based on utility plant in service as of December 31, 2002 and was developed utilizing the Straight Line Method, the Broad Group Procedure, and the Average Remaining Life Technique.[50] KU's current depreciation rates were approved in Case No. 2001-00140 based on a settlement, and the depreciation study filed in that case was based on plant in service as of December 31, 1999.

[49] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 25.

[50] Robinson Direct Testimony at 1 and 6.

The AG opposed KU's proposed increase, citing several problems with the new depreciation rates as well as some of the net salvage values included in those rates. The AG argued that the net salvage incorporated into KU's proposed depreciation rates was not reflective of the actual net salvage experienced by KU, included future inflation in the estimates of future net salvage expense, and included retirement costs that KU likely would never incur and had no legal obligation to incur.[51] The AG contended that KU's depreciation proposal is not consistent with FERC Order No. 631, which requires separate accounting for the cost of removal collected.[52] Lastly, the AG stated that the service lives used for several transmission and distribution plant accounts were incorrect.[53]

The AG recalculated the proposed depreciation rates by correcting the incorrect service lives and excluding the net salvage component. In lieu of retaining the net salvage component in depreciation rates, the AG proposed an annual net salvage allowance of zero for KU, since it had been experiencing positive net salvage during its actual 5-year average experience. The AG contended that the net salvage allowance is consistent with the requirements of FERC Order No. 631. Based on his recalculation, the AG proposed to reduce KU's test-year depreciation expense by $23,126,000.[54] The AG also suggested that $235,100,000 in overstated depreciation reserve should be

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[51] AG's Post-Hearing Brief at 7-12.

[52] Majoros Depreciation Direct Testimony at 28-29 of 51.

[53] Id. at 46-48 of 51.

[54] Majoros Accounting Direct Testimony, Exhibit MJM-7.

returned to ratepayers over a 10-year period;[55] but he did not include this amount in his proposed depreciation adjustment.

KU disagreed with the AG's criticisms of the proposed depreciation rates. Concerning the treatment of net salvage, KU argued that the AG's approach would have the effect of deferring removal costs to the end of the life of the asset. This deferral would result in intergenerational inequities because the customers who use the asset today are not paying the cost of removal today. Rather, those who are customers at the end of the asset life would have to pay the cost of removal.[56] Concerning the AG's claim that separating the net salvage component from depreciation rates is required by FERC Order No. 631, KU noted that this claim is not supported by the language in the FERC Order.[57] KU also stated that the AG's proposed net salvage allowance was rarely accepted by regulatory agencies and that the AG's citations to previous Commission decisions in electric cooperative cases did not disclose the entire decision.[58] Lastly, KU stated that the AG's selection of the longest available service lives for certain transmission and distribution assets reflected a "results-oriented" approach to determining depreciation rates.[59]

Based on a comprehensive review of both depreciation studies, the Commission has concerns about each of them. For KU's study, the Commission has concerns about

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[55] AG's Post-Hearing Brief at 15.

[56] Joint Post-Hearing Brief of LG&E and KU at 43.

[57] Id. at 47.

[58] Id. at 43.

[59] Id. at 47-48.

the inclusion of an inflation adjustment for the removal costs. Depreciation methods inherently recognize inflationary effects, since the depreciation rates are based upon comparisons of the original cost of the asset to the current cost of removal. This recognition assumes that future inflation rates will be similar to historical inflation rates. If it can be adequately demonstrated that future inflation rates will be different from the historical inflation rates, an inflation adjustment would be reasonable. However, to properly reflect this change in inflation rates, the effects of inflation currently incorporated in the accumulated depreciation would need to be removed. In response to a data request, KU provided a revision of its proposed depreciation rates that did not include adjustments based upon future estimates of inflation or other judgmental factors.[60] After reviewing these rates, the Commission believes there are still problems related to the inflation adjustment that was contained in KU's initial depreciation study. Therefore, the Commission finds that KU's depreciation study should be rejected.

Concerning the AG's study, except for its recognition of KU's double counting of inflation, the Commission finds little justification for the AG's position and cannot accept his proposals as reasonable. The AG proposes that net salvage be based on a 5-year average. KU contends that the 5-year average is not appropriate because of intercompany transfers between LG&E and KU.[61] The Commission notes that the major reason for basing depreciation rates on an analysis of historical records is the expectation that the future is likely to follow trends that have occurred in the past.

[60] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 24(b), corrected in Robinson Rebuttal Testimony at 53 and Rebuttal Exhibit EMR-7.

[61] Robinson Rebuttal Testimony at 16.

Therefore, it is not reasonable to use a 5-year average that contains unrepresentative data, but rather it would be more reasonable to use a longer time period in which such anomalies are likely to be averaged out.

The AG's claim that KU likely would never incur, or had no legal obligation to incur, the included retirement costs is irrelevant. The real question is whether it is reasonable to capitalize the cost of removal in order to recover those costs over the life of the investment. Capitalizing the cost of removal is a common practice and it has been accepted by this Commission for a number of years. The AG has not presented sufficient evidence in this case to persuade us to change this practice.

The AG has also suggested that $235,100,000[62] of alleged over-stated depreciation reserve be amortized back to ratepayers over 10 years. What the AG seems to have not recognized is that when the remaining life technique is utilized, one of the early steps in the process of calculating remaining life rates is to calculate a theoretical reserve. The amount of deviation, whether positive or negative, of the actual reserves from the calculated theoretical reserves is then spread over the remaining life of the investment. Amortizing the deviation from the theoretical reserve over the remaining life of the investment is reasonable, and is normally incorporated in the depreciation rates. The performance of depreciation studies on a regular basis, including the determination of the current deviation from the theoretical depreciation reserve, is a reasonable alternative to an amortization over a fixed period of years.

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[62] The AG did not provide a schedule showing the determination of the $235,100,000 but instead references approximately 20 pages of detailed accounting printouts as the source of the figure. See Majoros ARO and SFAS 143 Direct Testimony at 21.

The AG's extension of certain transmission and distribution asset service lives appears to be arbitrary rather than based on objective data. Depreciation estimates are just that - estimates. There are zones of reasonableness within which reasonable people will disagree. However, it is not reasonable to always select the service life that produces the lowest depreciation rates. Therefore, the Commission finds that the depreciation study submitted by the AG should also be rejected.

The Commission is especially concerned by the AG's interpretation of the provisions of FERC Order No. 631. As discussed above, FERC Order No. 631 generally adopted the provisions of SFAS No. 143. The AG's proposal to establish a net salvage allowance relates to non-ARO assets, those assets for which KU does not have a legal retirement obligation. Concerning the removal costs associated with these non-ARO assets, FERC Order No. 631 states:

> 37. The purpose of this rule is to establish uniform accounting requirements for the recognition of liabilities for legal obligations associated with the retirement of tangible long-lived assets. <u>The accounting for removal costs that do not qualify as legal retirement obligations falls outside the scope of this rule.</u> The Commission is aware that there is an ongoing discussion in the accounting community as to whether the cost of removal should be considered as a component of depreciation. <u>However, this issue is beyond the scope of this rule and we are not convinced that there is a need to fundamentally change accounting concepts at this time.</u>
> 38. Instead we will require jurisdictional entities to <u>maintain separate subsidiary records for cost of removal for non-legal retirement obligations</u> that are included as specific identifiable allowances recorded in accumulated deprecation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. (emphasis added)

The language in FERC Order No. 631 clearly does not require the separation of the net salvage component from depreciation rates or the creation of a net salvage allowance as advocated by the AG. The requirement that separate subsidiary records be maintained is significantly different from requiring separation from depreciation rates.

Based on our findings to reject both of the depreciation studies submitted in this record, the Commission has normalized KU's test-year depreciation expense by applying the current depreciation rates to the utility plant in service as of September 30, 2003. This results in an increase to KU's jurisdictional depreciation expense of $412,065.[63] The Commission further recognizes KU's willingness to file a new depreciation study by the earlier of its next general rate case or June 30, 2007, based on plant in service as of a date no earlier than one year prior to the filing. This proposal is reasonable and will be accepted by the Commission.

<u>Labor and Labor-Related Costs</u>

KU proposed an increase in its jurisdictional labor and labor-related costs of $1,002,076. The proposed adjustment reflected the annualization of wages and salaries for the test year, the associated impact on payroll taxes, and an increase in the 401(k) company match.[64] When preparing the adjustment, KU assumed that Social Security and Medicare taxes would apply to 100 percent of the wage increase. It subsequently determined that at the end of year 2003, 99.06 percent of the wages did

[63] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(a), page 3 of 7. For total company operations, the normalized depreciation expense increase was $472,016. Applying the jurisdictional allocation factor of 87.299 percent results in a Kentucky jurisdictional increase of $412,065.

[64] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.12.

not exceed the Social Security wage limit, and it revised the increase proposed for the payroll taxes.[65]

The Commission believes that the labor adjustment should reflect the impact of the Social Security wage limit. The approach utilized by KU to determine the impact of this wage limit is reasonable. Based on this revised payroll tax adjustment, the Commission finds that KU's jurisdictional labor and labor-related costs should be increased by $1,001,546.[66]

Pension and Post-Retirement Expenses

KU proposed to increase its test-year jurisdictional expense for pensions and post-retirement expenses by $3,014,859. KU explained that this adjustment was necessary to reflect the 2003 known and measurable changes in the expenses as determined by its actuary.

The AG opposed this adjustment on the basis that KU was locking into base rates a very high level of pension and post-retirement expense that would very probably decline in the next few years. The AG argued that low interest rates and changes in the pension and post-retirement plan asset values contributed to the high level of expense KU was seeking to recover in this case. The AG contended that interest rates should begin to increase over the next decade and that the value of the pension and post-retirement plan asset values would probably increase too. The AG noted that most

[65] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(d)(3).

[66] The increase of $1,001,546 reflects an increase in wages of $1,024,366, plus a payroll tax increase of $77,767, plus an increase in the 401(k) company match of $25,404. These components total $1,127,537. Applying the jurisdictional allocation factor of 88.826 percent results in the Kentucky jurisdictional increase of $1,001,546.

companies do not fully revalue their pension assets each year, but rather use a "smoothing" technique when determining the plan asset values. The AG claimed that the rejection of KU's proposed adjustment would be consistent with the Commission's treatment of this expense in Case No. 2000-00080.[67]

KU disagreed with the AG's position and asserted that the assumptions underlying the AG's testimony were incorrect and not supported. KU noted that the assumption that low interest rates have contributed to the rise in the pension and post-retirement expense is not necessarily correct. Depending on the plan demographics, a lower interest rate may not always cause increases in the interest cost component. KU stated that its external auditor does not permit it or the other LG&E Energy companies to use the "smoothing" technique, but instead requires the use of the fair market value methodology. KU argued that the AG's unsupported speculation does not eliminate the fact that the proposed increase in pension and post-retirement expense is a known and measurable adjustment that should be adopted.[68]

The Commission has in previous cases recognized the results of current actuarial studies in determining the reasonable level of pension and post-retirement expenses to include for rate-making purposes.[69] Here, KU has provided substantial

[67] Majoros Accounting Direct Testimony at 10-16.

[68] Scott Rebuttal Testimony at 11-14.

[69] See Case No. 2000-00373, May 21, 2001 Order at 13-14 and Case No. 2001-00244, Adjustment of Rates of Fleming-Mason Energy Cooperative Corporation, final Order dated August 7, 2002 at 15-16.

evidence to support its adjustment and we find it persuasive. The Commission also notes that KU's pension and post-retirement plans are currently underfunded.[70]

The Commission is not persuaded by the AG's arguments. The determination of pension and post-retirement benefit obligations and expenses is a very complex calculation, yet the AG isolates and comments on only two of many factors that are considered in those calculations. The AG has offered very little tangible evidence in support of his assumptions. While citing the Commission's decision in Case No. 2000-00080 as support for his proposed disallowance of KU's adjustment, the AG has not explained how the circumstances described in that decision are applicable to KU's current situation.[71] Therefore, the Commission finds that KU's proposal to increase its jurisdictional pension and post-retirement expense is reasonable and should be approved.

The Commission does have concerns about the underfunded status of KU's pension and post-retirement plans. KU should develop and implement a plan that eliminates the underfunding within a reasonable period of time. This plan should be filed with the Commission within one year from the date of this Order. In addition, KU should file progress reports describing the progress made in eliminating the underfunding of its pension and post-retirement plans. The progress reports should be

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[70] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 9.

[71] In Case No. 2000-00080, LG&E had proposed an adjustment to pension expense based on a 5-year average of historical pension costs. The AG's adjustment had been based on an actuarial estimate rather than a full actuarial report for calendar year 2000. After noting problems with both approaches, the Commission rejected both adjustments and left pension expense at the test-year level. See Case No. 2000-00080, September 27, 2000 Order at 33-35.

filed every two years, and will be due with the filing of KU's annual financial report. The first progress report should be filed by March 31, 2007.

Storm Damage Expense

KU proposed to normalize its storm damage expense by using a 4-year historic average adjusted for inflation. KU noted that it only had 4 years of historical data available for this adjustment, and that the February 2003 ice storm expenses were not included in the calculation of the proposed adjustment. KU stated that this was the same methodology utilized by the Commission in Case No. 1990-00158. The normalization resulted in a jurisdictional decrease of $473,014 over the test-year actual expense.

While the Commission would prefer the use of a 10-year historic average, that data is not available and we will agree with the methodology used by KU. However, the inflation factor was not determined in a manner consistent with the approach used by the Commission in previous cases. The inflation factor previously used by the Commission is based upon the Consumer Price Index – All Urban Consumers ("CPI-U").[72] To determine the inflation factor for a particular year, the Commission divides the CPI-U for the base year by the CPI-U for the particular year.[73] The Commission has recalculated the storm damage expense adjustment using the inflation factor approach

[72] KU provided the CPI-U for the 4-year period in its response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(f).

[73] In this case, the base year is 2003. The calculation of the inflation factor for 2000 would take the CPI-U for 2003 divided by the CPI-U for 2000, in this example, 184.0 divided by 172.2. This results in an inflation factor for 2000 of 1.0685.

previously utilized and determined that KU's jurisdictional storm damage expense should be decreased by $474,209.

Rate Case Expense

When KU filed its rate case, it estimated that the total cost of the case would be $1,057,368. KU requested the recovery of its rate case expenses over a 3-year period, noting that this approach was consistent with previous Commission decisions. Based on the estimated rate case expenses, KU included a rate case expense of $352,456. Throughout this proceeding, KU has been filing updated rate case expense information. KU's latest update of actual rate case expense shows a total expense of $1,190,654.[74]

Consistent with previous decisions, the Commission believes that only the actual, reasonable rate case expenses incurred in presenting this case should be recovered over a 3-year period. However, a review of KU's invoices for legal services reveals that the descriptions of services provided have been redacted for several line items on the basis that the information was protected by the attorney-client privilege.[75] KU later provided an affidavit of its counsel to affirm that the redacted legal costs were associated with this rate case.[76] The Commission recognizes and appreciates KU's right to assert its privilege to not disclose the nature of certain legal work performed by

[74] KU Updates of the Responses to the Commission Staff's First Data Request dated December 19, 2003, Items 43, 44, and 57, filed May 28, 2004. KU has provided supporting documentation for all rate case expenses reported throughout this proceeding. The last update reported expenses of $1,190,710, but the Commission determined there was an error in the math on the schedule of expenses.

[75] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 1, pages 8, 14, 17-18, and 21-25 of 83.

[76] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 3(c).

its attorneys. However, when a utility seeks to recover an expenditure in its rates, the Commission is obligated to review the nature of that expenditure to verify that it is just and reasonable. In this instance, we are unable to determine from the evidence of record the nature of certain legal services performed and whether those services were related to this rate case. Therefore, the Commission finds that $18,929 should be disallowed from the latest reported actual rate case expense. The Commission has calculated that the first year of a 3-year amortization of the actual rate case expenses is $390,575 and jurisdictional operating expenses have been increased by this amount.

Injuries and Damages

KU proposed to adjust its test-year expense for injuries and damages based on normalizing the actual expenses for a 5-year period, adjusted for inflation. KU used the same methodology that it proposed for adjusting its storm damage expense, except that it excluded its test-year expenses and based the adjustment on the past 5 years rather than 4 years. KU determined its jurisdictional injuries and damages expense needed to be increased by $261,138. KU subsequently stated that a 10-year historical period would result in a better representation of normal expenses, and it recalculated the adjustment for injuries and damages using the same methodology as it did for storm damage expense, but with a 10-year period. The recalculation produced an increase in expense of $1,218,999.[77]

The Commission finds it reasonable to calculate this adjustment using the same methodology used to determine the storm damage expense adjustment. Like storm damages, the injuries and damages expense can fluctuate significantly from year to

[77] Scott Rebuttal Testimony at 6-7 and VLS Rebuttal Exhibit 2, page 2 of 2.

year. The 10-year historic average, adjusted for inflation, should produce a more reasonable ongoing level of expense. The recalculated adjustment in KU's rebuttal testimony used the same inflation factors as KU used in its storm damage expense adjustment. As discussed previously, the inflation factors were not determined in a manner consistent with previous Commission decisions. The Commission has calculated the 10-year historic average for injuries and damages, adjusted for inflation. Based upon this calculation, the Commission finds that KU's jurisdictional injuries and damages expense should be increased by $1,238,006.

Information Technology Staff Reduction

In October 2003, LG&E Energy Services, Inc. reduced its Information Technology staff by 27 employees. KU proposed a jurisdictional operating expense reduction of $601,682, to reflect the savings from this staff reduction, offset by the first year of a 3-year amortization of the costs to achieve the reduction. KU determined the savings from the reduction based on payroll expense, payroll tax, and the 401(k) plan match.[78]

The Commission notes that KU did not recognize savings from the Team Incentive Awards ("TIA") program in its calculation of this adjustment.[79] The Commission finds that these savings should be included in the calculation of the

[78] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.26.

[79] KU indicated that the TIA savings resulting from this staffing reduction would be $77,514 on a total company basis. See Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 21.

adjustment. Consequently, KU's jurisdictional operating expenses should be reduced by $670,534.[80]

Nitrogen Oxide ("NOx") Expense

Under the terms of its current power contract with Owensboro Municipal Utilities ("OMU"), KU is obligated to pay OMU an increase in demand charges for KU's portion of OMU's environmental compliance with NOx regulations beginning July 1, 2004. KU proposed a jurisdictional expense increase of $1,959,879, which reflects its estimate of the increases in demand charges that will begin on July 1, 2004.

The increase in the purchased power demand costs is associated with OMU's debt service on its NOx compliance facilities. The payment of this additional debt service is recognized in the current contract between KU and OMU. The debt service dates are fixed and will not change, and KU will be billed the debt service in July 2004 once the project is declared commercially operational.[81] The interest rate on the debt is a variable rate. KU's actual purchased power demand costs from OMU could fluctuate monthly depending on the percentage of OMU's capacity that KU uses and the interest rate on the debt.[82]

While the Commission agrees that KU will have to pay increased demand charges to OMU due to the debt service on OMU's NOx compliance facilities, the

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[80] The adjustment was recalculated using the format shown in Rives Exhibit 1, Schedule 1.26 and increasing line 7 by the TIA expense savings of $77,514. The 88.826 percent jurisdictional factor was applied to the net cost reduction to arrive at the $670,534.

[81] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(l)(1) and Attachment to the Response, page 1 of 3.

[82] T.E., Volume II, May 5, 2004, at 156-157.

amount of that payment is not sufficiently measurable. The payments to OMU could vary from the amounts KU has estimated due to different levels of capacity used by KU and fluctuations in the variable interest rate charged for the NOx facilities debt. In addition, KU is not expected to begin incurring this expense until 9 months after the end of its test year in this case. The Commission generally has not recognized adjustments occurring that far beyond the end of the test year. Based upon these factors, the Commission finds that KU's estimate of its increased OMU demand charge is not sufficiently measurable to permit inclusion for rate-making purposes. Therefore, KU's proposed adjustment is rejected.

February 2003 Ice Storm Expenses

Between February 14-16, 2003, KU's distribution system was impacted by a significant ice storm. KU incurred $15,540,679 in jurisdictional operating and maintenance expenses due to the storm, and received an insurance reimbursement for $8,944,009 during the test year. KU proposed to defer and to amortize the unreimbursed balance of the ice storm expenses over a 5-year period, contending this approach was consistent with the Commission's treatment of 1974 tornado damages for LG&E.[83] KU's proposal would net the first year's amortization expense of $1,319,334 against the unreimbursed balance of $6,596,670, resulting in a reduction in test-year jurisdictional operating expenses of $5,277,336.

The unreimbursed ice storm expenses were recorded as expenses during 2003 and, as such, were included in the calculation of KU's earnings under its calendar year

[83] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.31 and Scott Direct Testimony at 14.

2003 ESM.[84] For calendar year 2003, KU experienced an earnings deficit of $24,157,776.[85] Under the provisions of KU's ESM, 40 percent of this deficit, or $16,232,669, was recovered through an ESM factor charged on ratepayers bills beginning in April 2004.[86] While acknowledging that the unreimbursed ice storm expenses were included in the ESM calculations for 2003, KU argued that its proposed adjustment in the rate case was an attempt to normalize this type of expense in base rates. KU excluded the unreimbursed ice storm expenses from its storm damage expense adjustment to avoid skewing the results for the storm damage expense calculation.[87]

Given the nature and significance of the event, the Commission believes that KU's proposal to defer and amortize over 5 years the February 2003 ice storm is reasonable. However, we do not agree on the amount to be deferred. While KU has focused its arguments on establishing a reasonable level of expense to be included for rate-making purposes, it has ignored the fact that a portion of the expenses it proposes to defer are already being recovered from ratepayers through its ESM. As the terms of the ESM Settlement, discussed previously in this Order, provide that the calendar year 2003 ESM factor is to be accepted as filed, the Commission will modify the amount of unreimbursed ice storm expenses recovered through base rates.

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[84] T.E., Volume II, May 5, 2004, at 158.

[85] See Case No. 2004-00070, Form 1, line 4.

[86] Forty percent of the 2003 earnings deficit is $9,663,110. The total amount collected through the ESM factor from ratepayers reflects 40 percent of the earnings deficit grossed up for income taxes.

[87] T.E., Volume II, May 5, 2004, at 159-160.

The Commission has reduced the unreimbursed ice storm expenses by 40 percent, leaving $3,958,002 eligible for deferral and amortization. The first year of a 5-year amortization of this amount equals $791,600. The adjusted first-year amortization will then be netted against the test-year total unreimbursed ice storm expense to determine the adjustment to jurisdictional operating expenses. Based on these calculations, the Commission finds that KU's jurisdictional operating expenses should be reduced by $5,805,070.

Retirements at Green River and Pineville

KU proposed to reduce its jurisdictional operating and maintenance expenses by $705,035 to reflect the retirement of its Green River Units 1 and 2. KU incurred these expenses during the test year, but since KU planned to retire the units in early 2004, it removed the expenses for rate-making purposes. During the processing of this case, it was discovered that KU had paid property taxes on these units and the jurisdictional amount of the property taxes was $153.[88] KU noted that due to FERC accounting for the retirement of Green River Units 1 and 2, the net book asset value associated with the generating units would not be reduced; consequently, KU's property taxes may not actually reduce.[89]

Regardless of how the retirement has been accounted for by KU, the Commission believes that if the asset is not providing service to ratepayers and has been retired, no costs associated with the retired asset should be recovered from

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[88] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 8.

[89] Id.

ratepayers. Therefore, the Commission finds that KU's adjustment to remove jurisdictional expenses resulting from the retirement of Green River Units 1 and 2 should be increased by $153 to a total adjustment of $705,188.

In December 2002, KU retired the Pineville Unit 3 generating unit. KU acknowledged that there were jurisdictional operating and maintenance expenses and property taxes associated with Pineville Unit 3 in its test-year operating expenses.[90] KU stated that it was an oversight that these expenses had not been removed from the test year and agreed such an adjustment should be made.[91] However, KU raised the same concern about the property taxes associated with Pineville Unit 3 as it did for the Green River Units 1 and 2.[92]

The Commission believes the operating and maintenance expenses and property taxes associated with the retired Pineville Unit 3 should be excluded for rate-making purposes, as was done for the Green River Units 1 and 2 retirements. Therefore, the Commission finds that jurisdictional operating expenses should be reduced by $22,963.

Miscellaneous Expenses

During the test year, KU recorded charitable contributions of $16,694 in accounts other than Account No. 426. KU agreed that the charitable contributions that had been recorded in error in accounts other than Account No. 426 should be removed for rate-

[90] Response to KIUC's Second Data Request dated March 1, 2004, Items 6 and 8.

[91] T.E., Volume II, May 5, 2004, at 153-154.

[92] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 7.

making purposes.[93] The Commission agrees that the charitable contributions should be excluded for rate-making purposes and has reduced jurisdictional operating expenses by $16,694.

During the test year, KU incurred jurisdictional expenses of $51,989 for employee gifts, award banquets, and other social events. KU argued that the expenses were reasonable and should be charged to ratepayers because they reward employees in connection with KU's safety programs and provided incentives to motivate and reward employees.[94]

The Commission believes that the expenses for employee gifts, award banquets, and social events should be excluded for rate-making purposes. In previous cases,[95] the Commission has not included these types of costs when determining rates, and KU has not provided adequate justification to support a different treatment. In addition, the Commission notes that emphasis on safety and incentives to encourage employee performance are incorporated into KU's TIA program. KU did agree that there was some overlap between the TIA program and the purpose for these expenses.[96]

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[93] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 35.

[94] Id., Item 39.

[95] See Case No. 1990-00041, An Adjustment of Gas and Electric Rates of The Union Light, Heat and Power Company, final Order dated October 2,1990 at 28-29; Case No. 1997-00066, An Adjustment of General Rates of Delta Natural Gas Company, Inc., final Order dated May 1, 1998 at 16-17; and Case No. 2001-00244, August 7, 2002 Order at 27-28.

[96] T.E., Volume II, May 5, 2004, at 176.

Therefore, the Commission will reduce KU's jurisdictional operating expenses by $51,989.

The Commission supports KU's efforts to reinforce the need for safety among their employees and encourages KU to develop appropriate safety programs. In future rate case, the Commission will reconsider the treatment of safety-related awards to the extent that KU can provide adequate documentation to show that these awards and other activities are integral components of a formal safety program.

During the test year, KU was a member of the Edison Electric Institute ("EEI") and allocated dues of $147,837 to its Kentucky jurisdiction. During the proceeding, KU was questioned about the activities of EEI funded by the membership dues. KU acknowledged that a portion of the EEI dues was associated with legislative advocacy and public relations and that it should be excluded for rate-making purposes. KU proposed that 31.55 percent of its EEI dues, or $46,643, be excluded.[97]

The Commission has reviewed the description of the various activities funded by the EEI dues,[98] and finds that the portion of the dues associated with legislative advocacy, regulatory advocacy, and public relations should be excluded for rate-making purposes. The description of regulatory advocacy appears to be a form of lobbying activity, which the Commission has not included for rate-making purposes in previous

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[97] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 11.

[98] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 40.

cases. These three categories account for 45.35 percent of the EEI dues.[99] Applying the 45.35 percent exclusion to the test-year jurisdictional EEI dues results in a reduction of $67,044.[100]

Based on these conclusions, the Commission has reduced jurisdictional miscellaneous expenses by $135,727.

Kentucky Income Tax Rate

KU determined that its jurisdictional federal and Kentucky income tax expense would be reduced by $16,152,919, based upon its proposed adjustments to jurisdictional revenues and expenses. KU's calculation reflected the use of the statutory federal income tax rate of 35 percent and the statutory Kentucky income tax rate of 8.25 percent.

The AG proposed that LG&E's effective Kentucky income tax rate for tax year 2002 of 7.87 percent should be used in all of KU's income tax and income tax-related calculations. The AG assumed that LG&E's effective tax rate would apply to KU, since both LG&E and KU pay the same Kentucky taxes.[101] The AG did not file any testimony in the KU case explaining his reasons for using the Kentucky effective income tax rate.

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[99] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 11, page 2 of 3.

[100] Jurisdictional EEI dues of $147,837 times 45.35 percent equals $67,044.

[101] Response to the Commission Staff's First Data Request to the AG dated April 6, 2004, Item 4. KU's effective income tax rate for 2002 was 7.64 percent excluding credits and 7.35 percent including credits; See Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 15(e)(2).

However, the AG has advocated for consistency in the rate-making treatment of adjustments in this case and the LG&E case.[102]

KU opposed the use of the Kentucky effective income tax rate, noting that the Commission has always used the statutory tax rate and that consistent treatment should be afforded to KU. KU argued that the effective tax rate reflects the impacts of credits and apportionment adjustments from out-of-state activities, which could change in the future. KU stated that the use of the effective tax rate would ignore the fact that it pays taxes in Virginia and Tennessee. If the effective tax rate is to be used, KU reasoned that the Virginia tax should be excluded in the determination of the effective tax rate, which in this case would be 7.98 percent.[103]

As stated previously, the AG filed no testimony to support the use of the effective Kentucky income tax rate, but apparently has relied on the testimony he filed in the LG&E rate case, Case No. 2003-00433. The Commission takes administrative notice of its reasons for rejecting the AG's position in that case, and affirms those reasons in this proceeding. Consistent with our expressed concern in Case No. 2003-00433 on this issue, the proper treatment of taxes paid in Virginia and Tennessee would have to be addressed if the effective Kentucky income tax rate is to be utilized. Therefore, the Commission finds that the statutory Kentucky income tax rate should be utilized for all income tax and income tax-related adjustments in this rate case. In KU's next rate case, it should address in detail the use of the effective tax rate for rate-making purposes.

[102] AG's Post-Hearing Brief at 26.

[103] Rives Rebuttal Testimony at 9-10.

Based upon these findings and the Commission's determination of the jurisdictional revenue and expense adjustments, the Commission has reduced KU's electric income tax expense $16,622,465.

Interest Synchronization

KU proposed to reduce its jurisdictional interest expense by $1,618,028, which resulted in an increase to jurisdictional income tax expense of $653,076.[104] KU stated that it followed the methodology used by the Commission in Case No. 2000-00080. KU multiplied its proposed adjusted jurisdictional capitalization by its proposed weighted average cost of debt to determine its normalized jurisdictional interest expense. The normalized interest expense was then compared to the test-year actual interest expense per KU's books.

The Commission has recalculated the interest synchronization adjustment, reflecting the debt components of KU's jurisdictional capitalization, the corresponding interest cost rates found reasonable in this Order, and the statutory Kentucky income tax rate. The Commission has determined that KU's jurisdictional interest expense should increase $759,017, resulting in a reduction in income taxes of $306,358.

Pro Forma Net Operating Income Summary

After consideration of all pro forma adjustments and applicable income taxes, the adjusted net operating income for KU's jurisdictional operations is as follows:

Operating Revenues	$710,376,288
Operating Expenses	649,144,765
Adjusted Electric Net Operating Income	$ 61,231,523

[104] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.35.

RATE OF RETURN

Capital Structure

KU proposed an adjusted test-year-end jurisdictional capital structure containing 36.70 percent long-term debt, 5.90 percent short-term debt, 2.95 percent accounts receivable securitization, 2.39 percent preferred stock, and 52.06 percent common equity.[105] As discussed previously in this Order, KU has allocated several adjustments to its capitalization on a pro rata basis or to common equity only as it determined appropriate.[106] During the proceeding, KU stated it had considered the Commission's policy of recognizing the impact on capital cost and capital structure of significant post-test-year issues of debt or equity. KU has updated its capital structure to reflect post-test-year changes, with the last update reflecting financial information as of March 31, 2004.[107] Using this latest financial information, KU determined its capital structure as 41.95 percent long-term debt, 2.49 percent short-term debt, 2.26 percent preferred stock, and 53.30 percent common equity. This updated capital structure did not reflect an adjustment for KU's minimum pension liability as of December 31, 2003. In March

[105] Rives Direct Testimony, Rives Exhibit 2.

[106] KU allocated adjustments for the removal of the investment in Electric Energy, Inc., the removal of other investments, the removal of reimbursed capital invested to repair combustion turbines at the E. W. Brown Generating Station, the retirement of the Green River Units 1 and 2, and the removal of its Post-1994 environmental compliance plan investments on a pro rata basis to all components of capitalization. The proposed adjustments for the minimum pension liability to Other Comprehensive Income and the removal of undistributed subsidiary earnings were allocated to common equity only.

[107] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 12. KU's update that reflected financial information as of March 31, 2004 was filed with the Commission on April 29, 2004.

2004, KU applied the accounting decision announced by FERC concerning the creation of a regulatory asset to reverse the impact of the minimum pension liability.

The AG proposed an adjusted test-year-end jurisdictional capital structure for KU containing 36.99 percent long-term debt, 5.95 percent short-term debt, 2.97 percent accounts receivable securitization, 2.41 percent preferred stock, and 51.67 percent common equity.[108] The only difference from KU's proposal was that the AG rejected KU's treatment of the minimum pension liability. The AG did not oppose KU updating its the capital structure, but the AG did state that the capital structure ratios could be updated beyond the test year only if the changes were minor so that any change in the company's financial risk would also be minor. Changes beyond the test year that affected the financial risk should not be allowed, according to the AG.[109]

In December 2000, the Commission approved KU's 3-year pilot accounts receivable securization program in Case No. 2000-00490.[110] At the end of the pilot period, KU decided not to seek a continuation of the program, and consistent with the decision in Case No. 2000-00490, the accounts receivable securization program was terminated on January 16, 2004. KU replaced the funding provided by the accounts

[108] Majoros Accounting Direct Testimony, Exhibit MJM-3.

[109] Weaver Testimony at 77-78.

[110] Case No. 2000-00490, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving the Transfer of Certain Financial Assets, final Order dated December 13, 2000.

receivable securization program with a mix of short-term and long-term debt from Fidelia, Inc. ("Fidelia").[111]

As correctly noted by KU, the Commission in previous cases has recognized the impact on the capital structure of significant post-test-year issues of debt or equity in order to determine the appropriate capital structure. Consequently, the Commission finds it is reasonable to recognize the termination of the accounts receivable securization program and the issuance of debt from Fidelia in the determination of the capital structure.

However, we do not agree with KU's proposal to simply use the updated capital structure as of March 31, 2004. Unlike its debt, KU did not issue any new shares of common stock. The March 31, 2004 financial information reflects the current level of net income from operations in Retained Earnings. As discussed previously in this Order, the Commission has recognized the adjustment to test-year-end common equity for the minimum pension liability. That minimum pension liability reflected the determination made at December 31, 2002. The application of the FERC accounting decision and creation of the regulatory asset reflected in the March 31, 2004 financial information reflect a minimum pension liability determined as of December 31, 2003. If the Commission were to use the capital structure based on the March 31, 2004 financial information, there would be a mismatch related to the minimum pension liability. The Commission's decision to allow the reversal of the December 31, 2002 minimum

[111] Fidelia is owned by E.ON North America Inc. and E.ON US Holding GmbH, which are subsidiaries of E.ON. See Response to the Commission Staff's First Data Request dated December 19, 2003, Item 2.

pension liability to common equity is the appropriate means of handling this issue, and it should be recognized in the capital structure.

As shown in Appendix E, the Commission finds KU's jurisdictional capital structure is as follows:

	Percent
Long-Term Debt	43.65
Short-Term Debt	2.41
Preferred Stock	2.36
Common Equity	51.58
Total Jurisdictional Capital Structure	100.00

Cost of Debt and Preferred Stock

KU proposed a cost of long-term debt of 3.12 percent, short-term debt of 1.06 percent, accounts receivable securization of 1.39 percent, and preferred stock of 5.68 percent.[112] As noted previously, KU filed updated financial information as of March 31, 2004 that included updated cost rates. Based on this updated information, KU's cost of long-term debt is 3.28 percent, short-term debt is 0.98 percent, and preferred stock is 5.64 percent.[113]

The AG used KU's costs of debt and preferred stock as filed in its application. The AG agreed that if interest rates or other capital cost rates change, such changes should be used to determine of the rate of return so that KU will have a reasonable opportunity to earn its allowed rate of return.[114]

[112] Rives Direct Testimony, Rives Exhibit 2.

[113] Updated Monthly Response to the Commission Staff's First Data Request dated December 19, 2003, Item 43, filed April 29, 2004.

[114] Weaver Testimony at 77.

The Commission finds it appropriate to recognize the cost rates for debt and preferred stock as of March 31, 2004 when determining the overall cost of capital for KU's jurisdictional operations. Updates to KU's debt and preferred stock cost rates constitute known and measurable adjustment and using these updates, rather than the test-year-end cost rates, is more representative of the period in which the rates established in this Order will be in effect. These cost rates will be applied to the jurisdictional capital structure determined herein. Therefore, the Commission finds the cost of long-term debt to be 3.28 percent, short-term debt to be 0.98 percent, and preferred stock to be 5.64 percent.

Return on Equity

KU estimated its required return on equity ("ROE") using four methods: the capital asset pricing model ("CAPM"), the discounted cash flow method ("DCF"), two risk premium analyses, and a comparable earning approach.[115] The CAPM analysis includes an adjustment of 60 basis points in order to recognize a size premium for some of the low- and mid-capitalization companies in the comparison group. KU explained that it employed multiple methods in determining its cost of equity because of potential measurement errors in the models as a result of industry changes, such as merger activity and price volatility.

Based on the results of the four methods, KU recommends an ROE range for its jurisdictional operations of 10.75 to 11.25 percent.[116] KU recommends awarding the

[115] Rosenberg Direct Testimony at 2.

[116] Id. at 4.

upper end of the range, 11.25 percent, in order to recognize its efficient operations and the current uncertain business climate for utilities.[117]

KU employed a proxy group in its analysis, consisting of electric utility companies similar in risk to its electric operations. KU proposed the use of proxy companies because, as a subsidiary of LG&E Energy, it is not publicly traded. The companies were selected from the Electric Utility category of *The Value Line Investment Survey*. The selected companies had to have overall senior bond ratings of Aa/A from Moody's Investor Service and AA/A from Standard & Poor's ("S&P") rating service and could not be currently involved in major merger activity. Companies were also excluded if they had significant unregulated operations, if they did not pay a dividend, or if they expected to cut their dividend.

As part of its analysis, KU provided a discussion of the role that ROE plays in how the financial community regards a utility company. KU states that accounting scandals, federal and state investigations, and other fallout from the collapse of Enron have shaken investor confidence in the energy industry. The result is more intense scrutiny of companies and a scarcity of financing at a time when many energy companies need to refinance billions of dollars of debt. At the time of its application, KU stated that S&P had reported 41 utility issuer credit rating downgrades, as compared to only eight upgrades during 2003. Moody's had downgraded roughly a third of the utilities it follows, as compared to the 10 percent annual average downgrades it has issued over the past 19 years. KU argued that these actions indicate less tolerance for financial weakness in a utility and that they have increased the cost of financing to

[117] Id.

weaker companies. In support of its argument, KU provided several citations from S&P publications that described the authorized returns for the regulated electric industry as insufficient and discussed the importance of profit potential and earning power in both credit protection and a company's ability to withstand business adversity.[118]

The AG criticized KU's ROE estimates on several grounds. The AG disagreed with several of the methodologies and inputs used by KU and with KU's small cap adjustment in the CAPM model. Two points which the AG identified as "fatal errors" were: (1) KU should not have used the Consumer Price Index ("CPI") when working with the Gross Domestic Product ("GDP") data; and (2) KU should have multiplied projected GDP growth and projected inflation growth instead of adding.[119] The AG argues that the small cap adjustment is already in the market prices of the mid- and low-capitalization companies used in the analysis and he concludes that KU's flawed analysis overstates its required cost of equity.

The AG estimated KU's required ROE using three methods: the CAPM, the bond-yield-plus-risk premium approach, and two versions of the DCF model.[120] Based on the results of these methods, the AG determined an ROE range of 9.75 to 10.25 percent, recommending that the Commission award 10.00 percent, the mid-point of the range.[121] During the hearing, the AG's witness stated that he would change his

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[118] Id. at 5-7.

[119] Weaver Testimony at 8.

[120] Id. at 32.

[121] Id. at 75.

recommendation from 10.00 percent to 10.25 percent if KU's ESM is eliminated as proposed in the settlement of this issue.[122]

The AG employed a proxy group in his analysis, consisting of utility companies classified as electric utilities by *Value Line*. The AG eliminated companies with a Financial Strength Rating below B, that *Value Line* did not recommend to investors, that had recently sold or purchased major assets, divested the majority of their generation plant, were involved in merger activity, or had a short operating history. The AG excluded Hawaiian Electric because it is not interconnected and also excluded any companies with a heavy reliance on hydro, nuclear or purchased power. Finally, the AG did not include any companies whose electric revenues as a percentage of total revenues were too dissimilar to that of KU.

The AG supported his analysis with a discussion of the economic conditions that would affect the ROE he recommended. He reviewed the GDP, inflation rates, interest rates and leading economic indicators. The AG believes that the GDP growth rate is within a range ideal for investment growth, that inflation is expected to continue to be low, and that interest rates are expected to be stable yet gradually increasing over the next 4 years. The AG concluded that the cost of equity for electric utilities would slowly increase over the near-term future. In fact, he made an adjustment in his DCF model to increase the results by 95 basis points to recognize an expected increase in interest rates.

On rebuttal, KU questioned the AG's recommended range since it differed by 50 to 100 basis points from the range recommended by this same witness in the ESM

[122] T.E., Volume III, May 6, 2004, at 177-179.

case, which was consolidated into this rate case. In his ESM testimony, the AG recommended a range of 10.25 to 11.25 percent, just 3 months prior to filing rate case testimony in which he recommends 9.75 to 10.25 percent.[123] In response to questions about how KU's risk had changed since the ESM case, the AG responded that the risk had changed very little.[124] To further demonstrate that the AG's recommendation is too low, KU compared the AG's recommendation to the 11.00 percent average electric ROE awarded nationally by utility regulatory commissions in 2003.[125]

In rebutting the AG's recommendation, KU states that the AG's analysis employs misstated and misapplied approaches. KU identifies calculations that it considers incorrectly performed and, when corrected, produce a higher result. KU also addresses the two "fatal errors" that the AG identified in KU's analysis. KU defended its use of inputs, reiterating that: (1) its use of the CPI as a measure of inflation was appropriate; and (2) the AG's contention that it had added rather than multiplied in the GDP calculation was, in fact, incorrect.[126]

The Commission finds merit in both KU's and the AG's recommended ranges for ROE and their critiques of each other's analyses. The Commission takes note of several sources of agreement between KU and the AG. As KU points out in its rebuttal testimony, the AG's recommended range in the consolidated ESM case overlaps

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[123] Rosenberg Rebuttal Testimony at 4.

[124] Response of the Attorney General to Requests for Information from KU, dated April 6, 2004, Item 27.

[125] Rosenberg Rebuttal Testimony at 2.

[126] Id. at 15-16.

substantially with KU's recommended range. The Commission also takes note of the AG's upward revision to his recommendation due to the agreement to discontinue the ESM mechanism. KU recommended the top of its range in order to recognize its efficient management and the uncertain business environment. While the Commission is prohibited from using an ROE award to either reward or punish a utility's management,[127] the Commission again takes note that the AG supported, in part, the need to increase the ROE award in recognition of the uncertain business climate when he increased some of his results by 95 basis points to allow for likely increases in interest rates in the near future. Finally, the Commission notes that KU has compared the returns on equity recommended by the intervenors to recent returns on equity allowed by regulators in other jurisdictions. KU states that an April 5, 2004 edition of *Major Rate Case Decisions* of Regulatory Research Associates reports an average allowed return for electric utilities in other jurisdictions of 11 percent in the first quarter of 2004.[128] The Commission takes notice that this same publication subsequently reported in May 2004 that the allowed returns on equity for electric utilities in other jurisdictions ranged from 9.50 percent to 11.22 percent.[129] While we agree with KU when it says that ROE awards granted by other commissions should not dictate this Commission's decision, those decisions do, however, indicate that the recommendations from both parties are well within the general level of recent allowed

[127] South Central Bell Telephone Company v. Utility Regulatory Commission, Ky., 637 S.W. 2d 649 (1982).

[128] Rosenberg Rebuttal Testimony at 2.

[129] Regulatory Research Associates, Inc., Regulatory Focus, May 26 and May 28, 2004.

returns. Therefore, after weighing all the evidence of record, the Commission finds that KU's required ROE falls within a range of 10.00 percent to 11.00 percent with a midpoint of 10.50 percent.

Rate of Return Summary

Applying the rates of 3.28 percent for long-term debt, 0.98 percent for short-term debt, 5.64 percent for preferred stock, and 10.50 percent for common equity to the capital structure produces an overall cost of capital of 7.00 percent. The cost of capital produces a rate of return on KU's jurisdictional rate base of 6.48 percent.

REVENUE REQUIREMENTS

The Commission has determined that, based upon a jurisdictional capitalization of $1,297,055,596 and an overall cost of capital of 7.00 percent, the net operating income that could be justified by the record for KU's jurisdictional operations is $90,793,892. Based on the adjustments found reasonable herein, KU's pro forma jurisdictional net operating income for the test year would be $61,231,523 and KU would need additional annual operating income of $29,562,369. After the provision for uncollectible accounts, the PSC Assessment, and state and federal income taxes, KU would have a revenue deficiency of $49,775,329. The calculation of this overall revenue deficiency is as follows:

Net Operating Income Found Reasonable	$ 90,793,892
Pro Forma Net Operating Income	61,231,523
Net Operating Income Deficiency	29,562,369
Gross Up Revenue Factor[130]	.5939161
Overall Revenue Deficiency	$ 49,775,329

However, as discussed above, KU is a signatory to the Partial Settlement and Stipulation. Thus, KU has indicated its willingness to accept an increase in annual jurisdictional revenues of $46,100,000. In determining the overall reasonableness of this alternative proposed increase by KU, the Commission has devoted a significant portion of this Order to evaluating KU's and the AG's proposed adjustments to capital, rate base, operating revenues, and operating expenses in light of our normal rate-making treatment.

The Commission has found that KU's required ROE falls within a range of 10.00 percent to 11.00 percent. Applying the findings herein on the reasonable costs of debt and preferred stock, and this range of return on common equity, to KU's jurisdictional capitalization would result in the following range of revenue increases:

Revenue Increase – 10.00 percent ROE	$44,097,178
Revenue Increase – KU Alternative Proposal	$46,100,000
Revenue Increase – Justifiable by Record	$49,775,329
Revenue Increase – 11.00 percent ROE	$55,235,088

Based on the findings and conclusions herein, the Commission finds that the earnings resulting from the adoption of KU's alternative proposal for its jurisdictional operations will fall within a range reasonable for both KU and its ratepayers. The $46,100,000

[130] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.37. The gross up revenue factor recognizes the impact the overall revenue deficiency will have on the provision for uncollectible accounts, the PSC Assessment, Kentucky income taxes, and federal income taxes.

revenue increase that KU is willing to accept will result in fair, just, and reasonable rates for KU. Therefore, the Commission will accept KU's alternative proposal that its jurisdictional revenues be increased by $46,100,000.

FINDINGS ON PARTIAL SETTLEMENT AND STIPULATION

Based upon a review of all aspects of the unanimous provisions in the Partial Settlement and Stipulation, an examination of the record, and being otherwise sufficiently advised, the Commission finds that the unanimous provisions are in the public interest and should be approved. These provisions include, but are not limited to, the VDT surcredit, a new HEA program, the dismissal of two specified court appeals, and the phase-out of the Pay As You Go program. The Commission's approval of the unanimous provisions is based solely on their reasonableness in toto and does not constitute precedent on any issue except as specifically provided for therein. Although we are approving all of the unanimous provisions, we have some concerns that need to be addressed at this time regarding certain aspects of those provisions.

New HEA Program

The Commission's approval of the unanimous provisions in the Partial Settlement and Stipulation includes the approval of the parameters of a new HEA program for KU. The HEA program will be funded by a 10-cent per residential meter per month charge for a period of 3 years. The charge will be set forth as a separate line item on each residential customer's bill.

The Commission certainly recognizes that low income households frequently have difficulties paying their utility bills. Consequently, financial assistance programs that subsidize the utility bills of those households are much needed. However, when these types of programs are funded through mandatory charges on residential utility bills, the common perception is that these charges are forced charitable contributions and they generate sincere objections from many ratepayers. While it will never be possible to eliminate every objection, ratepayers will certainly have a higher degree of acceptance of the funding for these programs if they can be assured that the funds collected will be fully accounted for and spent in the most efficient manner.

It is for this reason that the Commission has always urged the utility that will be the beneficiary to be a financial contributor to the assistance program. When an affected utility is at least partially funding an assistance program, the utility has a greater incentive to monitor the program expenditures and is in a better position to assure its ratepayers that the funds are being spent in the most efficient manner. Consequently, the Commission is disappointed that KU has chosen not to be a financial contributor to the HEA program which it has agreed to implement. We urge KU to reconsider this decision, but we recognize that we have no authority to require KU to fund such a program.

In any event, there is a real need for KU to actively monitor the implementation, operation, and expenditures of the HEA program. The Commission expects KU to fulfill this role so it can provide its ratepayers with the assurances they demand and deserve regarding the efficient expenditure of the HEA funds.

The Partial Settlement and Stipulation did not address when the 10-cent per residential meter per month charge would begin. The Commission does not believe it would be reasonable for this charge to begin on the same effective date as the rates contained in the Partial Settlement and Stipulation, primarily because the programmatic details of the HEA program have not been submitted to the Commission for approval as agreed to by the parties. The Commission finds that the HEA program 10-cent per residential meter per month charge should not be collected from ratepayers until the Commission has approved the programmatic details. The Partial Settlement and Stipulation envisions the HEA program to have a commencement date of October 1, 2004. The Commission believes it will need 60 days to review the programmatic details. Therefore, the Commission expects that the programmatic details for the new HEA program would be submitted for approval no later than August 1, 2004.

In addition, prior Commission Orders outlined several concerns about previous HEA programs in the Orders in Case No. 2001-00323.[131] The Commission continues to have those same concerns, and expects the proponents of this new HEA to address those concerns when the programmatic details are submitted to the Commission for its review and approval.

OTHER ISSUES

Curtailable Service

On June 17, 2004, KU filed a letter, which the Commission will treat as a motion, regarding a potential problem related to proposed changes to its curtailable service tariff. Those changes, as set forth in the unanimous provisions of the Partial Settlement and Stipulation shorten the notice of interruption, increase the maximum number of hours of interruption, and increase the potential frequency of interruptions. KU believes

[131] Case No. 2001-00323, Joint Application of Louisville Gas and Electric Company, Metro Human Needs Alliance, People Organized and Working for Energy Reform, Kentucky Association for Community Action, and Jefferson County Government for the Establishment of a Home Energy Assistance Program, final Order dated December 27, 2001; rehearing Order dated January 29, 2002.

that due to these changes some customers may, for operational reasons, want to switch from curtailable service to firm service. Consequently, KU is requesting authority to waive the 3-year notice required for a customer to terminate service under the tariff. This authority will permit KU to give the seven customers currently on this tariff the option to terminate service immediately, rather than be required to continue taking curtailable service for an additional 3 years.

Based on the significance of the changes in the terms and conditions of curtailable service, the Commission finds that KU's request to waive the 3-year notice of termination is reasonable. However, it is impractical for KU and a curtailable customer to switch rate schedules either immediately or on the effective date of the revised curtailable service tariff. Therefore, KU will be authorized to contact curtailable customers immediately upon issuance of this Order and inform them that they have a one-time opportunity to waive the 3-year notice of termination. Those customers will have until July 31, 2004 to notify KU if they elect to terminate curtailable service and switch to a firm service tariff.

Midwest Independent Transmission System Operator, Inc. ("MISO") Exit Fee

KU is currently a member of the Midwest Independent Transmission System Operator, Inc. ("MISO"), a regional transmission organization. In Case No. 2003-00266,[132] KU has requested authority to exit MISO and recover any exit fee from ratepayers. In this rate case, KU and the AG have addressed how the exit fee should be accounted for and what rate-making treatment is appropriate in the event the

[132] Case No. 2003-00266, Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

Commission authorizes KU to exit MISO. However, since the Commission has not yet decided whether KU should exit MISO, issues related to the accounting and rate-making treatment for an exit fee are premature. These issues will be addressed, if necessary in Case No. 2003-00266.

The "Global Settlement"

On October 31, 2001, LG&E, KU, the AG, and KIUC filed a unanimous settlement agreement that was intended to operate as a full and complete resolution of five cases then pending before the Commission.[133] This settlement agreement, referred to as the "Global Settlement," was approved by Commission Order on December 3, 2001. Several of the provisions of the Global Settlement directly affected adjustments proposed by KU in this rate case.

Article 1.0 of the Global Settlement provided that KU would perform a new depreciation study no later than calendar year 2004 based upon utility plant in service as of December 31, 2003 and when completed the new study would be filed with the Commission. KU did perform a new depreciation study which was filed in this rate case, but it was based on utility plant in service as of December 31, 2002. KU contended that this depreciation study was in compliance with the Global Settlement, arguing that, "the

[133] The five cases were Case No. 2001-00054, The Annual Earnings Sharing Mechanism Filing of Louisville Gas and Electric Company; Case No. 2001-00055, The Annual Earnings Sharing Mechanism Filing of Kentucky Utilities Company; Case No. 2001-00140, Application of Kentucky Utilities Company for an Order Approving Revised Depreciation Rates; Case No. 2001-00141, Application of Louisville Gas and Electric Company for an Order Approving Revised Depreciation Rates; and Case No. 2001-00169, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving Proposed Deferred Debits and Declaring the Amortization of the Deferred Debits to be Included in Earnings Sharing Mechanism Calculations.

defining limit on the previous commitment was the timing of another study (e.g., 'no later than calendar year 2004')," and that it "did not believe the plant-in-service date was intended to be the defining limit …."[134]

Article 2.0 of the Global Settlement addressed issues related to the KU's VDT workforce reduction and authorized KU to establish a regulatory asset which would include the expenses incurred to achieve the savings associated with the VDT workforce reduction. At the time the Global Settlement was approved, the regulatory asset was to be established based on estimated expenses. Later, the regulatory asset was to be adjusted to reflect actual VDT-related expenses as of December 31, 2001. However, for rate-making purposes, the actual expenses could not exceed the preliminary estimated expenses. During this case, KU disclosed that it had increased the balance in the VDT regulatory asset by $1,169,056 for expenses incurred after December 31, 2001.[135] KU contended that recording these additional expenses as part of the regulatory asset was consistent with the recording of the estimated expenses permitted when the Commission approved the Global Settlement. KU argued that it was in compliance with the terms of the Global Settlement because these additional expenses did not cause the regulatory asset balance to exceed the settlement amount of the expenses. KU stated that while it did record the additional expenses as part of the regulatory asset, it did not make an adjustment to the net savings returned to

[134] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 23.

[135] KU recorded these additional expenses in the regulatory asset account between December 2002 and July 2003. See Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 17(b)(1).

ratepayers through the VDT surcredit.[136] KU did include adjustments in this rate case to revise the VDT amortization expense to correspond with the regulatory asset as it was recorded on December 31, 2001.

The Commission is concerned by KU's interpretation of provisions of the Global Settlement as reflected in this rate case. Contrary to KU's interpretation of the Global Settlement provision concerning the timing of the next depreciation study, it is clear that the calendar year 2004 deadline for filing and the utilization of utility plant in service as of December 31, 2003 are both controlling dates. Concerning the VDT regulatory asset, the Global Settlement did not contain any provisions that authorized KU to continue to increase the balance of the regulatory asset established on December 31, 2001. The fact that the additional expenses did not exceed the originally estimated expenses does not justify KU's accounting.

The Commission notes that, in Case No. 2002-00072,[137] KU previously misinterpreted provisions of the Global Settlement. In that case the Commission found that the Global Settlement did not authorize KU to adjust its monthly capitalization to retroactively reflect the VDT workforce reduction, and KU was required to recalculate its ESM annual filing for calendar year 2001.

The Commission will not require KU to submit a new depreciation study in compliance with the dates established in the Global Settlement since we are accepting KU's proposal to prepare a new depreciation study no later than June 30, 2007. In

[136] Response to the Commission Staff's Fourth Data Request dated April 14, 2004, Item 3.

[137] Case No. 2001-00072, Kentucky Utilities Company's Annual Earnings Sharing Mechanism Filing for Calendar Year 2001.

addition, we will not require KU to remove the post-2001 additions to its VDT regulatory asset since the amortization expenses that were included for rate-making purposes were consistent with the provisions of the Global Settlement and the regulatory asset is not included in rate base. Consequently, ratepayers have not been harmed by KU's actions.

The Commission is concerned, however, that on three separate occasions KU has incorrectly interpreted and deviated from significant provisions of the Global Settlement. The unanimous provisions of the Partial Settlement and Stipulation approved herein are significantly more encompassing and complex than the provisions contained in the Global Settlement. The Commission cautions KU that, absent prior Commission approval, there should be no deviations from either the unanimous provisions of that document of KU's timetable for filing a new depreciation study.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by KU in its application are denied.

2. The ESM Settlement, attached hereto as Appendix B, is approved in its entirety and KU's ESM is terminated except for continued collections for 2003 operations.

3. The unanimous provisions in the Partial Settlement and Stipulation, attached hereto as Appendix C, are approved in its entirety.

4. The rates and charges in KU's Exhibit 1, set forth in Appendix A hereto, are the fair, just, and reasonable rates for KU to charge for electric service, and these rates are approved for service rendered on and after July 1, 2004.

5. KU shall, within 20 days of the date of this Order, file its revised tariff sheets setting out the rates and tariff changes approved herein.

6. Within one year from the date of this Order, KU shall file with the Commission a plan developed and implemented that eliminates the underfunding of its pension and post-retirement plans. KU shall also file progress reports on its progress to eliminate the underfunding of the pension and post-retirement plans as described within this Order.

7. KU shall submit for Commission approval the programmatic details associated with its HEA program no later than August 1, 2004.

8. KU shall not bill its residential customers 10 cents per meter per month for the HEA until authorized to do so upon Commission approval of the HEA programmatic details.

9. KU's request for a one-time waiver through July 31, 2004 of the 3-year customer notice to terminate curtailable service is granted.

Done at Frankfort, Kentucky, this 30th day of June, 2004.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00434 DATED June 30, 2004

The following rates and charges are prescribed for the customers in the area served by Kentucky Utilities Company, consistent with KU Exhibit 1. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

SCHEDULE RS
RESIDENTIAL SERVICE

Customer Charge per Month:	$5.00
Energy Charge per kWh:	$ .04404

SCHEDULE A.E.S.
ALL ELECTRIC SCHOOL

Energy Charge per kWh:	$ .04227

SCHEDULE GS
GENERAL SERVICE RATE

Customer Charge per Month:	$10.00
Energy Charge per kWh:	$ .05327

SCHEDULE LP
LARGE POWER SERVICE PRIMARY VOLTAGE

Customer Charge per Month:	$75.00
Demand Charge per kW:	$ 6.26
Energy Charge per kWh:	$ .02200

SCHEDULE LP
LARGE POWER SERVICE SECONDARY VOLTAGE

Customer Charge per Month:	$75.00
Demand Charge per kW:	$ 6.65
Energy Charge per kWh:	$ .02200

SCHEDULE LP
LARGE POWER SERVICE TRANSMISSION VOLTAGE

Customer Charge per Month:	$75.00
Demand Charge per kW:	$ 5.92
Energy Charge per kWh:	$ .02200

SCHEDULE LCI-TOD
LARGE COMMERCIAL/INDUSTRIAL TIME-OF-DAY RATE PRIMARY VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kW:	
On-Peak Demand	$ 4.58
Off-Peak Demand	$ .73
Energy Charge per kWh:	$ .02200

SCHEDULE LCI-TOD
LARGE COMMERCIAL/INDUSTRIAL TIME-OF-DAY RATE TRANSMISSION VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kW:	
On-Peak Demand	$ 4.39
Off-Peak Demand	$ .73
Energy Charge per kWh:	$ .02200

SCHEDULE MP
COAL MINING POWER SERVICE PRIMARY VOLTAGE

Customer Charge per Month:	$75.00
Demand Charge per kW:	$ 4.69
Energy Charge per kWh:	$ .02400

SCHEDULE MP
COAL MINING POWER SERVICE TRANSMISSION VOLTAGE

Customer Charge per Month:	$75.00
Demand Charge per kW:	$ 4.57
Energy Charge per kWh:	$ .02400

SCHEDULE LMP-TOD
LARGE MINE POWER TIME-OF-DAY RATE PRIMARY VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kW:	
On-Peak Demand	$ 5.39
Off-Peak Demand	$ .73
Energy Charge per kWh:	$ .02000

SCHEDULE LMP-TOD
LARGE MINE POWER TIME-OF-DAY RATE TRANSMISSION VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kW:	
On-Peak Demand	$ 4.85
Off-Peak Demand	$ .73
Energy Charge per kWh:	$ .02000

SCHEDULE LI-TOD
LARGE INDUSTRIAL TIME-OF-DAY RATE PRIMARY VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge:	
Standard Load Charge per KVA	
On-Peak	$ 4.58
Off-Peak	$ .73
Fluctuating Load Charge per KVA	
On-Peak	$ 2.29
Off-Peak	$ .37
Energy Charge per kWh:	$ .0220

SCHEDULE LI-TOD
LARGE INDUSTRIAL TIME-OF-DAY RATE TRANSMISSION VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge:	
Standard Load Charge per KVA	
On-Peak	$ 4.39
Off-Peak	$ .73
Fluctuating Load Charge per KVA	
On-Peak	$ 2.20
Off-Peak	$ .37
Energy Charge per kWh:	$ .0220

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT

Customer Charge per Month:	$ 5.00
Energy Charge per kWh:	$ .04404

SCHEDULE ST. LT.
STREET LIGHTING SERVICE

Rate per Light per Month: (Lumens Approximate)

	Standard	Ornamental
Incandescent System:		
1,000 Lumens	$ 2.26	$ 2.91
2,500 Lumens	$ 2.75	$ 3.55
4,000 Lumens	$ 3.94	$ 4.88

6,000 Lumens	$ 5.24	$ 6.29
Mercury Vapor:		
7,000 Lumens	$ 6.63	$ 8.89
10,000 Lumens	$ 7.64	$ 9.65
20,000 Lumens	$ 8.98	$ 10.59
High Pressure Sodium:		
4,000 Lumens	$ 5.00	$ 7.62
5,800 Lumens	$ 5.43	$ 8.04
9,500 Lumens	$ 6.11	$ 8.92
22,000 Lumens	$ 9.02	$ 11.81
50,000 Lumens	$ 14.55	$ 17.34

SCHEDULE DEC. ST. LT.
STREET LIGHTING SERVICE

Rate per Light per Month: (Lumens Approximate)

Decorative Street Lighting Service:	
Acorn with Decorative Pole	
4,000 Lumens	$10.40
5,800 Lumens	$10.94
9,500 Lumens	$11.61
Acorn with Historic Pole	
4,000 Lumens	$16.32
5,800 Lumens	$16.85
9,500 Lumens	$17.53
Colonial	
4,000 Lumens	$ 6.86
5,800 Lumens	$ 7.30
9,500 Lumens	$ 7.90
Coach	
5,800 Lumens	$25.07
9,500 Lumens	$25.73
Contemporary	
5,800 Lumens	$12.60
9,500 Lumens	$15.01
22,500 Lumens	$17.40
50,000 Lumens	$22.53
Gran Ville	
16,000 Lumens	$38.28
Gran Ville Accessories:	
Single Crossarm Bracket	$16.28
Twin Crossarm Bracket	$18.12
24 Inch Banner Arm	$ 2.82

18 Inch Banner Arm	$ 2.60
Flagpole Holder	$ 1.20
Post-Mounted Receptacle	$16.90
Base-Mounted Receptacle	$16.31
Additional Receptacles	$ 2.31
Planter	$ 3.91
24 Inch Clamp on banner arm	$ 3.90

SCHEDULE P.O. LT.
PRIVATE OUTDOOR LIGHTING SERVICE

Standard (Served Overhead)	
Mercury Vapor	
7,000 Lumens	$ 7.61
20,000 Lumens	$ 8.98
High Pressure Sodium	
5,800 Lumens	$ 4.33
9,500 Lumens	$ 4.94
22,500 Lumens	$ 9.02
50,000 Lumens	$14.55
Directional (Served Overhead)	
High Pressure Sodium	
9,500 Lumens	$ 5.98
22,500 Lumens	$ 8.47
50,000 Lumens	$12.90
Metal Halide Commercial and Industrial Lighting	
Directional Fixture	
12,000 Lumens	$ 8.83
32,000 Lumens	$12.24
107,800 Lumens	$25.28
Directional Fixture with Wood Pole	
12,000 Lumens	$10.79
32,000 Lumens	$14.21
107,800 Lumens	$28.01
Directional Fixture with Metal Pole	
12,000 Lumens	$17.20
32,000 Lumens	$20.61
107,800 Lumens	$33.65
Contemporary Fixture Only	
12,000 Lumens	$ 9.92
32,000 Lumens	$13.78
107,800 Lumens	$27.82

Contemporary Fixture with Metal Pole	
12,000 Lumens	$18.30
32,000 Lumens	$22.14
107,800 Lumens	$36.19
Decorative HPS (Served Underground)	
Acorn with Decorative Pole	
4,000 Lumens	$10.40
5,800 Lumens	$10.94
9,500 Lumens	$11.62
Acorn with Historic Pole	
4,000 Lumens	$16.32
5,800 Lumens	$16.85
9,500 Lumens	$17.54
Colonial	
4,000 Lumens	$ 6.86
5,800 Lumens	$ 7.30
9,500 Lumens	$ 7.90
Coach	
5,800 Lumens	$25.07
9,500 Lumens	$25.73
Contemporary	
5,800 Lumens	$12.60
9,500 Lumens	$15.01
22,500 Lumens	$17.40
50,000 Lumens	$22.53
Gran Ville	
16,000 Lumens	$38.28

RATE CSR 1
CURTAILABLE SERVICE RIDER 1

	Transmission	Primary
Demand Credit per kW per Month	$ 3.10	$ 3.20
Non-compliance Charge Per kW Per Month	$ 16.00	$ 16.00

RATE CSR 2
CURTAILABLE SERVICE RIDER 2

	Transmission	Primary
Demand Credit per kW per Month	$ 4.09	$ 4.19
Non-compliance Charge Per kW Per Month	$ 16.00	$ 16.00

RATE CSR 3
CURTAILABLE SERVICE RIDER 3

	Transmission	Primary
Demand Credit per kW per Month	$ 3.10	$ 3.20
Non-compliance Charge Per kW Per Month	$ 16.00	$ 16.00

EXPERIMENTAL LOAD REDUCTION INCENTIVE RIDER

Rate: Up to $0.30 per kWh

EXPERIMENTAL SMALL TIME-OF-DAY SERVICE RATE

Customer Charge per Month:	$90.00
Demand Charge:	
Secondary Service per kW per Month	$ 6.65
Primary Service per kW per Month	$ 6.26
Transmission Service per kW per Month	$ 5.92
Energy Charge:	
On-Peak Energy per kWh	$ .02800
Off-Peak Energy per kWh	$ .01500

STANDARD RIDER FOR EXCESS FACILITIES

Charge for distribution facilities

Carrying Charge	.93%
Operating Expenses	.56%

STANDARD RIDER FOR REDUNDANT CAPACITY CHARGE

Capacity Reservation Charge Per kW Per Month

Secondary Distribution	$ .80
Primary Distribution	$ .63

RETURNED CHECK CHARGE

Rate:	$ 9.00

METER TEST CHARGE

Rate:	$ 31.40

DISCONNECT AND RECONNECT SERVICE CHARGE

Rate:	$ 20.00

SPECIAL CONTRACT
WESTVACO

Demand Charge Per kW Per Month:

Non-Interruptible Demand	$ 3.98
Interruptible Demand	$ 1.95
Energy Charge Per kWh:	$ .02200

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00434 DATED June 30, 2004

ESM SETTLEMENT AGREEMENT

Dated May 12, 2004

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 12th day of May 2004, by and between Louisville Gas and Electric Company ("LG&E"); Kentucky Utilities Company ("KU") (LG&E and KU are hereafter collectively referenced as "the Utilities"); Commonwealth of Kentucky, ex. rel. Gregory Stumbo, Attorney General, by and through the Office of Rate Intervention ("AG"); Kentucky Industrial Utility Customers, Inc. ("KIUC") and the interests of its participating members as represented by and **through** the KIUC; Commonwealth of Kentucky, Environmental and Public Protection Cabinet, Division of Energy ("KDOE"); the United States Department of Defense ("DOD); The Kroger Company ("Kroger"); Kentucky Association for Community Action, Inc. ("KACA"); 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 ("LFUCG); and North American Stainless, L.P. ("NAS") in the proceedings involving LG&E and KU which are the subject of this Settlement Agreement, ***as*** set forth below.

W I T N E S S E T R :

WHEREAS, LG&E filed on December 29, 2003 with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Rates, ***In** Re the Matter of: **An** Adjustment of the Gas and Electric Rates. Terms and Conditions of Louisville* Gar *and Electric Comuanv*, and the Commission has established Case No. 2003-00433 to review LG&E's base rate application;

WHEREAS, KU filed on December 29, 2003 with the Commission its Application for Authority to Adjust Rates, *In Re the Matter of: An Adjustment **of** the Electric Rates, Terms and Conditions of Kentucky Utilities Comuanv*, and the Commission has established Case No. 2003-00434 to review KU's base rate application;

WHEREAS, the AG, KIUC, KDOE and Kroger have been granted intervention by the Commission in both of the forgoing proceedings; MHNA, POWER, DOD and KACA have been granted intervention by the Commission in Case No. 2003-00433 only; and LFUCG, NAS and CAC have been granted intervention by the Commission in Case No. 2003-00434 only;

WHEREAS, on March 31, 2004, the Commission granted consolidation of Case No. 2003-00433 with the case captioned _In Re the Matter of An Investigation Pursuant to KRS 278.260 of the Earnings Sharing Mechanism Tariff of Louisville Gas and Electric Companv_, Case No. 2003-00335;

WHEREAS, on March 31, 2004, the Commission granted consolidation of Case No. 2003-00434 with the case entitled _In Re the Matter of: An Investigation Pursuant to KRS 278.260 of the Earnings Sharing Mechanism Tariff of Kentucky Utilities Companv_, Case No. 2003-00334;

WHEREAS, the AG and KIUC have been granted intervention by the Commission in both Case Nos. 2003-00334 and 2003-00335; and LFUCG has been granted intervention by the Commission in Case No. 2003-00334 only;

WHEREAS, LG&E's current Earnings Sharing Mechanism tariff was effective on January 2, 2003 pursuant to the Commission's Orders of December 20, 2002 and January 14, 2003 in Case No 2002-00473 (LG&E); and KU's current ESM tariff was effective on January 2, 2003 pursuant to the Commission's Orders of December 20,2002 and January 14,2003 in Case No. 2002-00472 (collectively the "ESM tariffs");

WHEREAS, on March 1, 2004 LG&E filed its Annual Earnings Sharing Mechanism Filing for Calendar Year 2003 in Case No. 2004-00069;

WHEREAS, on March 1,2004 KU filed its Annual Earnings Sharing Mechanism Filing for Calendar Year 2003 in Case No. 2004-00070;

WHEREAS, a prehearing conference, attended in person or by teleconference by representatives of the AG, KIUC, KDOE, DOD, Kroger, KACA, CAC, MHNA, POWER, LFUCG, NAS, the Commission Staff and the Utilities, took place on April 28, 2004 at the offices of the Commission during which a number of procedural and substantive issues were discussed, including potential settlement of certain issues pending before the Commission in Case Nos. 2003-00433 and 2003-00434, Case Nos. 2003-00334 and 2003-00335 (the "ESM renewal proceedings"), and Case Nos. 2004-00069 and 2004-00070 (the "2003 ESM proceedings"); and

WHEREAS, the signatories hereto desire to settle certain issues pending before the Commission in the rate proceedings, the ESM renewal proceedings and the 2003 ESM proceedings.

NOW, THEREFORE, for and in consideration of the premises and conditions set forth herein, the parties hereby agree as follows:

ARTICLE I. <u>**Earnings Sharing Mechanism ("ESM") Recoverv and Discontinuation**</u>

SECTION 1.1 Effective July 1,2004, the Earnings Sharing Mechanism, except as set forth in Sections 1.2 through 1.4 below, shall be discontinued,

SECTION 1.2 LG&E has filed with the Commission, in Case No. 2004-0069, the results for the 2003 ESM Reporting Period and the corresponding ESM billing factor pursuant to its ESM tariff. Beginning April 1, 2004, LG&E began billing its 2003 ESM factor in customer bills. The parties recommend the Commission issue an order in Case No.

2004-0069 approving the 2003 ESM factor as filed and authorizing LG&E to continue billing its ESM factor through March 31, 2005 and collect and retain all the revenues derived from the billing of 2003 ESM factor. Specifically, for the period of April 1, 2004 through April 30, 2004, LG&E should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.282%. And, specifically, for the period of May 1, 2004 through March 31, 2005, LG&E should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.360%.

SECTION 1.3 KU has filed with the Commission, in Case No. 2004-0070, the results for the 2003 ESM Reporting Period and the corresponding ESM billing factor pursuant to its ESM tariff. Beginning April 1, 2004, KU began billing its 2003 ESM factor in customer bills. The parties recommend the Commission issue an order in Case No. 2004-0070 approving the 2003 ESM factor as filed and authorizing KU to continue billing its ESM factor through March 31, 2005 and collect and retain all the revenues derived from the billing of 2003 ESM factor. Specifically, for the period of April 1, 2004 through April 30, 2004, KU should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.367%. And, specifically, for the period of May 1, 2004 through March 31, 2005, KU should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.330%.

SECTION I.4 No later than May 2005, the Utilities shall perform a final balancing adjustment to reconcile any over- or under-collection of the ESM revenues for the current ESM billing period, April 2004 through March 2005.

SECTION 1.5 The Utilities agree to waive their rights to make any billing or seek any collection under their respective ESM tariffs for the six-month period ending June 30, 2004, excluding the operation of the ESM mechanism as provided in Sections 1.2 through 1.4 above.

ARTICLE II. Approval of Settlement Agreement

SECTION 2.1 Following the execution of this Settlement Agreement, the signatories shall cause the Settlement Agreement to be filed with the Commission with a request to the Commission for consideration and approval of this Settlement Agreement by May ____, 2004.

SECTION 2.2 The signatories to this Settlement Agreement shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be accepted and approved.

SECTION 2.3 If the Commission issues a final order which accepts and approves this Settlement Agreement in its entirety, then the parties hereto hereby waive any and all claims or demands, asserted or unasserted, directly arising out of or in connection with the application or operation of the Utilities' respective ESMs in Case Nos. 2004-0069, 2004-070, 2003-00334 and 2003-00335, and all such claims or demands shall be deemed settled under or compromised, released and discharged by this Settlement Agreement.

SECTION 2.4 If the Commission does not accept and approve this Settlement Agreement in its entirety, then: (a) this Settlement Agreement shall be void and withdrawn by the parties hereto from further consideration by the Commission and none of the parties shall be bound by any of the provisions herein; and (b) neither the teims of this Settlement Agreement nor any matters raised during the settlement negotiations shall be binding on any of the signatories to this Settlement Agreement or be construed against any of the signatories.

SECTION 2.5 Should the Settlement Agreement be voided or vacated for any reason after the Commission has approved the Settlement. Agreement and thereafter any implementation of the terms of the Settlement Agreement has been made, then the parties shall be returned to the *status quo* existing at the time immediately prior to the execution of this agreement.

ARTICLE III. Additional Provisions

SECTION 3.1 This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

SECTION 3.2 This Settlement Agreement shall inure to the benefit of and be binding upon the parties hereto, their heirs, successors and assigns.

SECTION 3.3 This Settlement Agreement constitutes the complete agreement and understanding among the parties hereto, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

SECTION 3.4 For the purpose of this Settlement Agreement only, the terms are based upon the independent analysis of the parties to reflect a just and reasonable resolution of the issues herein and are the product of compromise and negotiation. Notwithstanding anything contained in the Settlement Agreement, the parties recognize and agree that the effects, if any, of any future events upon the operating income of LG&E or KU are unknown and this Settlement Agreement shall be implemented as written.

SECTION 3.5 Neither the Settlement Agreement nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Settlement Agreement. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

SECTION 3.6 The provisions of this Settlement Agreement shall not bar a party from seeking, or the Commission from reinstating, an ESM at some future time, in order to accomplish reasonable and valid regulatory objectives.

SECTION 3.7 Making this Settlement Agreement shall not be deemed in any respect to constitute an admission by any party hereto that any computation, formula, allegation, assertion or contention made by any other **party** in these proceedings is true or valid.

SECTION 3.8 The signatories hereto warrant that they have informed, advised, and consulted with the respective parties hereto in regard to the contents and significance of this agreement and based upon the foregoing are authorized to execute this Settlement Agreement on behalf of the parties hereto.

SECTION 3.9 This Settlement Agreement is subject to the acceptance of and approval by the Public Service Commission.

SECTION 3.10 This Settlement Agreement is a product of negotiation among all parties hereto, and no provision of this Settlement Agreement shall be strictly construed in favor of or against any party.

SECTION 3.11 This Settlement Agreement may be executed in multiple counterparts.

IN WITNESS WHEREOF, *the* parties hereto have hereunto affixed their signatures.

Louisville Gas and Electric Company
and Kentucky Utilities Company

HAVE READ AND AGREED:

By: ______________________
Kendrick R. Riggs, Counsel

-and-

By: ______________________
Dorothy E. O'Brien, Counsel

Commonwealth of Kentucky, **ex.** rel. Gregory Stumbo, Attorney General, by and through the Office of Rate Intervention

HAVE READ AND AGREED:

By: ______________________________
Elizabeth E. Blackford, Counsel

Kentucky Industrial Utility Customers, Inc.

HAVE READ AND AGREED:

By: ______________________

David F. Boehm, Counsel
Michael L. Kurtz, Counsel

Commonwealth of Kentucky,
Environmental **and** Public Protection Cabinet,
Division of Energy

HAVE READ AND AGREED:

By: ______________________

Iris Skidmore, Counsel

United States Department of Defense

HAVE SEEN AND AGREED:

By: ______________________

for David A. McCormick, Counsel

The Kroger Company

HAVE READ AND AGREED:

By:______________________________
David C. Brown, Counsel

Kentucky Association for Community
Action, Inc.

HAVE READ **AND** AGREED:

By: ______________________
Joe F. Childers, Counsel

Community Action Council for
Lexington-Fayette, Bourbon, Harrison
and Nicholas Counties, Inc.

HAVE READ AND AGREED:

By: ______________________
Joe F. Childers, Counsel

Metro Human Needs Alliance

HAVE READ AND AGREED:

By: Lisa Kilkelly

Lisa Kilkelly, Counsel

People Organized and Working for Energy Reform

HAVE READ AND AGREED:

Ey: Lisa Kilkelly

Lisa Kilkelly, Counsel

Lexington-Fayette Urban County Government

HAVE READ AND AGREED:

By: ____________________

David J. Barberie, Counsel

North American Stainless, L.P.

HAVE READ AND AGREED:

By: ______________________
Richard S. Taylor, Counsel

By: ______________________
Nathaniel K. Adams, General Counsel

By: ______________________
Kimberly McCann, Counsel

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00434 DATED June 30, 2004

PARTIAL SETTLEMENT AND STIPULATION

Dated May 12, 2004

PARTIAL SETTLEMENT AGREEMENT, STIPULATION AND RECOMMENDATION

This Partial Settlement Agreement, Stipulation and Recommendation ("Settlement Agreement") is entered into this 12th day of May 2004, by and between Louisville Gas **and** Electric Company ("LG&E"); Kentucky Utilities Company ("KU") (LG&E and KU are hereafter collectively referenced as "the Utilities"); Commonwealth of Kentucky, ex. rel. Gregory Stumbo, Attorney General, by and through the Office of Rate Intervention ("AG); Kentucky Industrial Utility Customers, Inc. ("KIUC") and the interests of its participating members as represented by and through the KIUC; Commonwealth of Kentucky, Environmental and Public Protection Cabinet, Division of Energy ("KDOE"); the United States Department of Defense ("DOD"); The Kroger Co.("Kroger"); Kentucky Association for Community Action, Inc. ("KACA"); 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 ("LFUCG"); and North American Stainless, L.P. ("NAS") in the proceedings involving LG&E and KU which are the subject of this Settlement Agreement, as set forth below.

W I T N E S S E T H:

WHEREAS, LG&E **filed** on December 29, 2003 with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Rates, ***In Re the Matter of An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company***, and the Commission has established Case No. 2003-00433 to review LG&E's base rate application;

WHEREAS, KU filed on December **29,** 2003 with the Commission its Application for Authority to Adjust Rates, ***In Re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company***, and the Commission has established Case No. 2003-

00434 to review KU's base rate application (Case Nos. 2003-00433 and 2003-00434 are hereafter collectively referenced as the "rate proceedings");

WHEREAS, the AG, KIUC, KDOE, KACA and Kroger have been granted intervention by the Commission in both of the rate proceedings; MHNA, POWER and DOD have been granted intervention by the Commission in Case No. 2003-00433 only; and LFUCG, NAS and CAC have been granted intervention by the Commission in Case No. 2003-00434 only;

WHEREAS, on March 31, 2004, the Commission granted consolidation of Case Nos. 2003-00433 and 2003-00434 with the case captioned *In the Matter of: Tariff Filing of Kentucky Utilities Company and Louisville Gas and Electric Company for Non-Conforming Load Customers*, Case No. 2003-00396 (which case had previously been consolidated with *In the Matter of: North American Stainless v. Kentucky Utilities Company*, Case No. 2003-00376).

WHEREAS, a prehearing conference, attended in person or by teleconference by representatives of the AG, KIUC, KDOE, DOD, Kroger, KACA, CAC, MHNA, POWER, LFUCG, NAS, the Commission Staff and the Utilities, took place on April 28, 2004 at the offices of the Commission during which a number of procedural and substantive issues were discussed, including potential settlement of certain issues pending before the Commission in the rate proceedings;

WHEREAS, on May 4, 2004, the hearing in the rate proceedings began and was adjourned for the purpose of exploring the possibility of settlement of the rate proceedings or stipulation of issues therein, which discussions were attended in person by representatives of the AG, KIUC, KDOE, DOD, Kroger, KACA, CAC, MHNA, POWER, LFIJCG, NAS, the Commission Staff and the Utilities;

WHEREAS, all of the signatories hereto desire to settle all the issues pending before the Commission in the rate proceedings, except for the AG, who is unwilling to settle the issue of the revenue requirements of LG&E's electric operations and KU's operations;

WHEREAS, it is understood by all signatories hereto that this Settlement Agreement is subject to the approval of the Commission, insofar as it constitutes an agreement by all parties to the rate proceedings for settlement, and does not represent agreement on any specific theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms and conditions;

WHEREAS, it is understood by all signatories hereto that, insofar as this Settlement Agreement does not recite the agreement of the **AG** to settle the issue of the revenue requirements of the LG&E electric operations and the KU operations, it is a stipulation among the signatories hereto other than the AG as to the foregoing revenue requirement issues, pursuant to 807 KAR 5:001, Section 4(6);

WHEREAS, the signatories have spent many hours, over several days, in order to reach the stipulations and agreements which form the basis of this Settlement Agreement;

WHEREAS, all of the signatories, who represent diverse interests and divergent viewpoints, agree that this Settlement Agreement, viewed in its entirety, is a fair, just and reasonable resolution of all the issues in the rate proceedings;

WHEREAS, the adoption of this Settlement Agreement will reduce the length of the hearing, simplify the briefing, and eliminate the possibility of, and any need for, rehearing on the issues stipulated and agreed to; and

WHEREAS, it is the position of the parties hereto that this Settlement Agreement is supported by sufficient and adequate data and information, and should be approved by the Commission.

NOW, THEREFORE, for and in consideration of the premises and conditions set forth herein, the parties hereby stipulate and agree as follows:

ARTICLE I. Revenue Requirement.

Section 1.1. The signatories hereto, except the AG, stipulate that the following annual increases in revenues for LG&E electric operations and for KU operations, for purposes of determining the rates of LG&E and KU in the rate proceedings, are fair, just and reasonable for the signatories and for all customers of LG&E (electric) and KU:

Section 1.1.1. LG&E Electric Operations: $43,400,000;

Section 1.1.2. KU Operations: $46,100,000.

The signatories hereto, including the AG, agree that any annual increase in revenues for LG&E electric operations and for KU operations will be effective July 1, 2004.

Section 1.2. The signatories hereto, including the AG, agree that, effective July 1, 2004, the annual increases in revenues for LG&E gas operations of $11,900,000, for purposes of determining the rates of LG&E gas operations in the rate proceedings, are fair, just and reasonable for the signatories and for all gas customers of LG&E.

ARTICLE II. Allocation of Revenue.

Section 2.1. The signatories hereto, including the AG, agree that the allocation of the annual revenue increase for LG&E electric operations, LG&E gas operations and for KU operations, as set forth on the allocation schedule designated Exhibit 1 hereto, in the rate proceedings is fair, just and reasonable for the signatories and for all customers of LG&E and KU. Notwithstanding the foregoing sentence, it is understood that the AG has only agreed that the percentages of the rate classes applicable to each LG&E electric operations rate class and each KU operations rate class on Exhibit 1 hereto are fair, just and reasonable and the AG has made no agreement of any other information relating to such LG&E electric operations or KU operations. All signatories hereto, including the AG, agree that the revenue increase to electric special contract customers set forth on Exhibi! **1** hereto shall be allocated such that each special contract customer shall have the same percentage increase in rates.

Section 2.2. The signatories hereto, except the AG, agree that, effective July 1. 2004, the Utilities shall implement the electric rates set forth on Exhibit 1, attached hereto, which rates the signatories hereto, except the AG, stipulate are fair, just and reasonable and should be approved by the Commission. All signatories hereto, including the AG, agree that. effective July 1, **2004,** the Utilities shall implement the **gas** rates set forth on Exhibit 1, attached hereto, which rates the signatories hereto agree are fair, just and reasonable and should be approved by the Commission.

Section2.3. The signatories hereto, including the AG, agree that the Utilities shall establish **a** pilot time-of-day program for commercial customers with a monthly demand between 250 kW and 2,000 kW. The rates, terms and conditions of said program shall be as set forth in the Stipulation, dated May **4,** 2004, between the Utilities and Kroger and filed in the rate proceedings. A copy of said Stipulation is attached hereto as Exhibit 2 and is incorporated by reference as though fully set forth herein. The forms of tariff designed to implement the Stipulation and the Settlement Agreement are attached hereto as Exhibit 2-A (LG&E) and Exhibit 2-B (KU).

ARTICLE III. Treatment of Certain Specific Issues.

Section 3.1. The signatories hereto, including the AG, agree that, after the date hereof, orders approving cost recovery of LG&E's and KU's environmental projects pursuant to KRS 278.183 shall be based upon an 11.0% return on common equity until directed by order of the Commission that a different rate of return shall be utilized.

Section 3.2. The signatories hereto, including the AG, agree that all of LG&E's gas purification and gas storage loss expenses shall be recovered as part of its Gas Supply Clause mechanism.

Section 3.3. The signatories hereto, except the AG, agree that the depreciation rates of the Utilities shall remain the same as approved in the orders of December 3, 2001, in Case Nos. 2001-140 and 2001-141, until the approval by the Commission of new depreciation rates for the Utilities, for which the

Utilities shall seek approval by filings made in their next general rate cases or June 30, 2007, whichever occurs earlier. The Utilities' depreciation filings shall be based on plant in service as of a date no earlier than one (1) year prior to such filing. From and after the effective date hereof, the Utilities shall maintain their books and records so that net salvage amounts may be identified.

Section 3.4. The signatories hereto, including the AG, agree that all costs associated with KU's 1994 environmental compliance plan (the "1994 Plan") approved in Case No. 93-465 and LG&E's 1995 environmental compliance plan (the "1995 Plan") approved in Case No. 94-332 shall be recovered in the Utilities' base rates, taking into account the Utilities' overall rate of return, and will be removed from the Utilities' monthly environmental surcharge filings, all in accordance with the details of such recovery set forth on Exhibit 3 hereto.

Section 3.5. The signatories hereto, including the AG, agree that, unless the Commission has already modified or terminated the Value Delivery Team ("VDT") surcredits in a subsequent rate case, six (6) months prior to the expiration of the sixty (60) month period in which the VDT surcredits are in operation, the Utilities shall file with the Commission a plan for the future ratemaking treatment of the VDT surcredits, the shareholder savings, the amortization of VDT costs and all other VDT-related issues. The VDT surcredit tariffs shall remain in effect following the expiration of the sixtieth (60^{th}) month until the Commission enters an order on the future ratemaking treatment of all VDT-related issues.

Section *3.6.* The signatories hereto, including the **AG,** agree that LG&E shall establish a real time pricing ("RTP") pilot program for LG&E's electric customers. The tam of the program shall be three **(3)** years. In each year, up to fifty (50) customers under Rate R and up to fifty (50) customers under Rate GS shall qualify for the program. During the second year of the program, LG&E shall propose to the Commission detailed plans, terms and conditions for the inclusion of customers under Rate LP in the program, such inclusion to take place during the second year of the program. Rate LP customers shall be eligible for participation in the program during the second and third years of the program in accordance with the Commission's approval of LG&E's proposal for inclusion of Rate LP customers. The customer-specific costs shall be recovered through a facilities charge incorporated into the applicable customer charges during the first six *(6)* months of the RTP pilot program. **After** six (6) months, the Utilities shall evaluate the level of participation in the pilot program and consider modifymg the treatment of such customer-specific charges to encourage participation in the RTP pilot program. The non customer-specific costs of modifying LG&E's customer billing system to bill customers under the RTP pilot program will be recovered pursuant to the RTP pilot program through a charge per kWh billed to customers taking service under Rates R, GS and LP in the same manner as the Demand-Side

Management ("DSM) Cost Recovery Component of LG&E's DSM Cost Recovery Mechanism. After the end of the three year term, LG&E will evaluate the performance of the RTP pilot program for the following purposes, including, but not limited to: (i) to determine the impact of the pilot program on its affected customers; (ii) to determine the amount of revenue loss from the pilot program, if any; (iii) to evaluate customer acceptance of the real time pricing program and (iv) to evaluate the potential for implementing the RTP program as either a permanent demand-side management program or as a standard rate schedule. LG&E shall file a report with the Commission describing its findings within six months after the first three years of implementation of the RTP pilot program. The RTP pilot program shall remain in effect until the program is modified or terminated by order of the Commission.

Section 3.7. The signatories hereto, including the AG, agree that the notice period for an Operational Flow Order pursuant to LG&E's Rate FT shall be twenty-four **(24)** hours.

Section 3.8. The signatories hereto, including the **AG,** agree that the miscellaneous charges of the Utilities shall be approved as proposed by the Utilities in the rate proceedings, except as follows: (i) the Disconnect-Reconnect Charge for LG&E electric customers, LG&E gas customers and KU electric customers shall be $20.00; and (ii) the KU After-Hours Reconnect Charge shall be withdrawn.

Section 3.9. The signatories hereto, including the AG, agree that the following monthly customer charges shall be implemented: (i) LG&E electric residential customers, $5.00 per month; (ii) LG&E gas residential customers, $8.50 per month; (iii) KU residential customers, $5.00 per month; (iv) LG&E GS electric single phase, $10.00 per month; (v) LG&E GS electric three phase, $15.00 per month; (vi) KU GS primary, $10.00 per month; and (vii) KU GS secondary, $10.00 per month. All other customer charges shall be implemented as proposed by the Utilities in their Applications filed on December 29,2003 in the rate proceedings.

Section 3.10. The signatories hereto, including the **AG,** agree that, for both LG&E and KU, Rate GS shall be available to electric customers with connected loads up to 500 kW.

Section 3.11. The signatories hereto, including the AG, agree that LG&E shall withdraw its Standard Riders for Summer **Air** Conditioning Service for its gas operations, and that customers served thereunder shall take service under otherwise applicable rate schedules.

Section 3.12. The signatories hereto, including the AG, agree that LG&E shall not bill an additional customer charge to Rate GS customers formerly taking service under the Rider for Electric Space Heating Service under Rate GS.

Section 3.13. The signatories hereto, including the AG, agree that LG&E shall eliminate the seasonal rate structure for Rate RS and shall implement a non-seasonally differentiated rate structure for Rate RS. Nothing contained in this Section shall preclude the Utilities from making a future proposal for a seasonal rate structure.

Section 3.14. The signatories hereto, including the AG, agree that, in conjunction with the AG, KACA, CAC, MHNA, and POWER, the Utilities will file plans for program administration with the Commission for year-round Home Energy Assistance ("HEA") programs in both of their respective service territories based solely upon a ten-cent per residential meter **per** month charge (the "HEA charge") for a period of three years. The HEA charge will be collected in the same manner as the DSM Cost Recovery Component of the Utilities' DSM Cost Recovery mechanism. The HEA programs shall be operated by existing social service providers ("Providers") with experience operating low-income energy assistance programs, who shall be entitled to recover actual operating expenses not to exceed ten percent (10%) of total HEA funds collected.

The signatories hereto, including the AG, agree that each HEA program will be subject to an outside independent annual audit conducted by an independent certified public accountant, in accordance with the Providers' existing audit requirements. Each audit shall include a detailed accounting of all expenses associated with administration of the program, which shall be **filed** annually with the Commission.

The signatories hereto, including the AG, further agree that KU shall be permitted recovery of its one-time information technology implementation costs through its DSM mechanism.

Section 3.15. The signatories hereto, including the AG, agree that the HEA programs to be filed shall have a commencement date of October 1,2004. Approval of this Settlement Agreement by the Commission shall constitute approval of the HEA parameters as proposed herein, subject to further review by the Commission of additional programmatic details. No money shall be distributed to the Providers pursuant to the HEA programs, or allocated pursuant to such programs, until such time as the Commission has issued final approval of the programmatic details.

Section 3.16. Within ninety days of the conclusion of the second year of the program, the Providers shall file with the Commission comprehensive program assessments to insure that the programs are meeting their respective established goals. Based upon those filings, and public hearings, if any, relating thereto, the Commission will then determine whether the HEA programs shall continue beyond three years and, if so, whether any modifications should be made to those programs.

Section 3.17. The signatories hereto, including the AG, who are parties to the respective Franklin Circuit Court actions hereby agree that upon approval of this Settlement Agreement by the Commission, they will jointly move the Franklin Circuit Court for the entry of an order dismissing the pending HEA and Pay As You Go ("PAYG") appeals, Civil Action Nos. 02-CI-00991 and 03-CI-00634, respectively.

Section 3.18. The signatories hereto, including the AG, agree that LG&E will phase out its PAYG program by limiting the program to existing customers **and** by removing those meters from existing customers as requested. as meters fail, or as customers move off the system. However, LG&E reserves the right to completely terminate the program upon sixty days advance notice to the Commission. LG&E and KU further agree that they will not seek approval of new prepaid metering programs for a period of at least five years from the date hereof, and that, after five years, approval by the Commission will be a necessary prerequisite to operating any new prepaid metering program.

Section 3.19. The signatories hereto, including the AG, agree that OMU NOx expenditures of $1 million per year incurred by KU pursuant to its contract with Owensboro Municipal Utility shall be recovered in KU's Environmental Cost Recovery filings pursuant to KRS 278.183. Recovery of the foregoing costs shall begin in April 2005 based upon the February 2005 expense month for KU.

Section 3.20. The signatories hereto, including the AG, agree that LG&E and KU shall offer a Curtailable Service Rider ("CSR1") to current customers who meet the eligibility requirements set forth in the proposed CSR1 tariff on such terms and conditions as specified in the proposed tariff subject to the following terms and conditions: (1) the customers shall be subject to curtailment for 250 hours annually; (2) the amount of the credit shall be $3.20 per kW for primary voltage customers and $3.10 per kW for transmission voltage customers; (3) the customers shall be entitled to 20 minutes notice of curtailment; (4) current customers shall have the option of buying through the curtailment at the market rate as determined by LG&E/KU; *(5)* in the event a customer elects to buy through a curtailment, the customer shall be required to purchase all of the demand to be curtailed on an hourly basis: and *(6)* this curtailable service rider is available only to those customers who are covered by an existing curtailable service rider as of the execution of this Settlement Agreement.

Section 3.21. The signatories hereto, including the AG, agree that new customers not currently served by an existing CSR will be eligible to take curtailable service under a new CSR tariff (CSR2) as originally filed by the Companies in the rate proceedings, except such customers will be able to buy through a request for curtailment only after having been on the CSR2 service for three years with no failure to curtail when requested.

Section 3.22. The signatories hereto, including the **AG,** agree that NAS's electric arc furnace operations shall receive electric service pursuant to the LI-TOD tariff, effective April 1, 2004, except as otherwise noted and which shall provide that the LI-TOD tariff shall be the same as the Non-Conforming Load Service Tariff ("NCLS") as proposed in Case No. 2003-00396 with the following changes:

(1) non-conforming load service shall be changed throughout to read large industrial-time of day (LI-TOD);

(2) the rates to be applied shall be the same rates applicable to customers on the LCI-TOD tariff;

(3) the demand charge shall he calculated by multiplying the rate established above by demand measured as Peak Demand **(KVA)** measured in 15 minute intervals plus the difference between Peak Demand measured in 5 minute intervals less Peak Demand measured in 15 minute intervals (if a positive number) multiplied by 0.5 times the rate, expressed as DC = [D15 +(D5-D15)0.5]R.

(4) Under the section of the tariff entitled System Contingencies and Industry System Performance Criteria the following additions are agreed:

a. The third sentence thereof shall be amended to limit the number of interruptions **per** month to no more than twenty with no carry-over from month to month. Within sixty days of the end of the applicable hilling period, upon request, information and documentation necessary for customer to verify that interruptions were caused by system contingencies as defined herein will be made available to customer;

b. Customers under the LI-TOD tariff may contract to curtail service upon notification by Company on the same terms and conditions as exist under the Curtailable Service Rider for LCI-TOD customers except requests for curtailment by the Companies shall not exceed 200 hours in the first year the Customer contracts for service, effective April 1, 2004, and 100 hours in each continuously succeeding year. Requests for curtailment shall he limited to on-peak periods specified in the LCI-TOD tariff.

c. All other provisions of the curtailable service rider as proposed in this Settlement Agreement for customers on the LCI-TOD tariff shall apply except that Customer may not buy through a request for curtailment by virtue of the unusual nature of the load of the Large Industrial class of customers.

d. System contingencies shall be defined in the tariff as:

In order to facilitate Company compliance with system contingencies and with NERC/ECAR System Performance Criteria, Customer will permit the Company to install electronic equipment and associated real time metering to permit Company interruption up to 95% of the Customer's load under this tariff when the LG&E Energy LLC System ("LEC System") experiences an unplanned outage or de-rate of LEC System-owned or purchased generation, or when Automatic Reserve Sharing is invoked within the ECAR or an ISO/RTO. LEC System as used herein shall consist of Company and Louisville Gas and Electric Company. Such equipment will electronically notify customer five (5) minutes before the electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes. The interruptions will not be accumulated and credited against the annual curtailment hours under this contract.

(5) Customers covered by the LI-TOD tariff as of **April 1**, 2004 shall have the option to contract for additional service for a period of not less

than five (5) years under the terms of the tariff by signing a contrzct for additional service by March 1, 2005 which commits service to begin, or to pay, demand charges as agreed in such contract no later than July 1, 2006 before the tariff is extended to other customers. If the option given to current customers herein is not exercised by the dates specified the option expires.

(6) The difference. if any, between the invoiced charges for electric service for the NAS electric arc furnace operations for the months of April, May, and June, 2004 actually paid by NAS and those charges ultimately billed as approved by the Commission shall be refunded to NAS as a billing credit going forward.

Section 3.23. The signatories hereto, including the AG, agree that, except as modified in this Settlement Agreement, the proposals of the Utilities in the rate proceedings shall be approved as filed.

ARTICLE IV. Miscellaneous Provisions.

Section 4.1. The signatories hereto, including the AG, agree that making this Settlement Agreement shall not be deemed in any respect to constitute an admission by any party hereto that any computation, formula, allegation, assertion or contention made by any other party in these proceedings is true or valid.

Section 4.2. The signatories hereto, including the AG, agree that the foregoing stipulations and agreements represent a fair, just and reasonable resolution of the issues addressed herein and request the Commission to approve the Settlement Agreement.

Section4.3. The signatories hereto, including the AG, agree that, following the execution of this Settlement Agreement, the signatories shall cause the Settlement Agreement to be filed with the Commission by May 11, 2004, together with a request to the Commission for consideration and approval of this Settlement Agreement.

Section 4.4. The signatories hereto, other than the Utilities and the AG, stipulate that they will withdraw the direct testimony of their witnesses in the rate proceedings. The signatories hereto, other than the AG, stipulate that they will not otherwise contest the Utilities' proposals in the rate proceedings regarding the subject matter of the Stipulation, and that they will refrain from cross-examination of the Utilities' witnesses during ihe rate proceedings, except insofar as such cross-examination is in support of the Stipulation.

Section 4.5. The signatories hereto, including the AG, agree that this Settlement Agreement is subject to the acceptance of and approval by the Public Service Commission. The signatones hereto, including the AG, further agree to act in good faith and to use their best efforts to recommend to the Commission that this Settlement Agreement be accepted and approved.

Section 4.6. The signatories hereto, including the **AG,** agree that, if the Commission does not accept and approve this Settlement Agreement in its entirety, then: (a) this Settlement Agreement shall be void and withdrawn by the parties hereto from further consideration by the Commission and none of the parties shall be bound by any of the provisions herein. provided that no party is precluded from advocating any position contained in this Settlement Agreement; and (b) neither the terms of this Settlement Agreement nor any matters raised during the settlement negotiations shall be binding on any of the signatones to this Settlement Agreement or be construed against any of the signatories.

Section 4.7. The signatories hereto, including the AG, agree that, should the Settlement Agreement be voided or vacated for any reason after the Commission has approved the Settlement Agreement, then the parties shall be returned to the ***status*** *quo* existing at the time immediately prior to the execution of this agreement.

Section 4.8. The signatories hereto, including the AG, agree that this Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

Section4.9. The signatories hereto, including the AG, agree that this Settlement Agreement shall inure to the benefit of and be binding upon the parties hereto, their successors and assigns.

Section 4.10. The signatories hereto, including the AG, agree that this Settlement Agreement constitutes the complete agreement and understanding among the parties hereto, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

Section 4.11. The signatories hereto, including the AG, agree that, for the purpose of this Settlement Agreement only, the terms are based upon the independent analysis of the parties to reflect a fair, just and reasonable resolution of the issues herein and are the product of compromise and negotiation.

Section 4.12. The signatories hereto, including the AG, agree that neither the Settlement Agreement nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Settlement Agreement. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

Section 4.13. The signatories hereto, including the AG, warrant that they have informed, advised, and consulted with the respective parties hereto in regard to the contents and significance of this Settlement Agreement and based upon the foregoing are authorized to execute this Settlement Agreement on behalf of the parties hereto.

Section 4.14. The signatories hereto, including the AG, agree that this Settlement Agreement is a product of negotiation among all parties hereto, and no provision of this Settlement Agreement shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Settlement Agreement, the parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Settlement Agreement shall be implemented as written.

Section **4.15.** The signatories hereto, including the AG, agree that this Settlement Agreement may be executed in multiple counterparts.

IN WITNESS WHEREOF, the parties hereto have hereunto affixed their signatures.

Louisville Gas and Electric Company
and Kentucky Utilities Company

HAVE SEEN AND AGREED:

By: ______________________
Kendrick R. Riggs, Counsel

-and-

By: ______________________
Dorothy E. O'Brien. Counsel

Commonwealth of Kentucky, **ex.** rel. Gregory Stumbo, Attorney General, by and through the **Office** of Rate Intervention

HAVE SEEN **AND** AGREED:

By: ____________________________

Elizabeth E. Blackford, Counsel

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: ______________________

David F. Roehm, Counsel
Michael L. Kurtz, Counsel

Commonwealth of Kentucky,
Environmental and Public Protection Cabinet,
Division of Energy

HAVE SEEN AND AGREED:

By: ______________________________
Iris Skidmore, Counsel

United States Department of Defense

HAVE SEEN AND AGREED:

By: Peter E. Nyers, for

David A. McCormick, Counsel

The Kroger Co.

HAVE SEEN AND AGREED:

By: ______________________________

David C. Brown, Counsel

Kentucky Association for Community
Action, Inc.

HAVE SEEN AND AGREED:

By:______________________________
Joe F. Childers, Counsel

Community Action Council for
Lexington-Fayettc, Bourbon, Harrison
and Nicholas Counties. Inc.

HAVE SEEN AND AGREED:

By: ______________________________
Joe F. Childers, Counsel

Metro Human Needs Alliance

HAVE SEEN AND AGREED:

By: ______________________________
Lisa Kilkelly, Counsel

People Organized and Working for Energy Reform

HAVE SEEN AND AGREED:

By: ~~Lisa Kilkelly~~

Lisa Kilkelly, Counsel

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By.________________________________

David J. Barberie, Counsel

North American Stainless. L.P.

HAVE SEEN AND AGREED:

By:______________________________
Richard S. Taylor, Counsel

By:______________________________
Nathaniel K. Adams, Counsel

By:______________________________
Kimberly S. McCann, Counsel

Kentucky Utilities Company
Summary of Proposed Electric Rate Increase by Rate Class
For the 12 months Ended September 30, 2002

	Adjusted Billings at Current Rates	Proposed Increase In Revenue As Filed	Percentage Increase	Settlement Increase	Percentage Increase	Increase as Percentage of Total
Residential	$ 252,910,745	$ 24,185,323	9.56%	$ 20,193,976	7.98%	43.763%
General Service	66,269,093	5,792,730	8.74%	$ 4,933,172	7.44%	10.691%
All Electric School Service Rate AES	3,955,546		0.00%	294,587	7.45%	0.638%
Combined Lighting & Power Service	226,957,349	18,885,564	8.32%	16,908,062	7.45%	36.642%
Comm./Industrial Time-of-Day	84,135,770	6,725,688	7.99%	2,048,936	2.44%	4.440%
Coal Mining Power Service	8,542,207	725.107	8.49%	638,188	7.47%	1.383%
Large Mine Power Time-of-Day	6,043,407	513.353	8.49%	453,462	7.50%	0.983%
Special Contract	14,551,478	(202,024)	-1.19%	(261.052)	-1.79%	-0.566%
Private Outdoor Lighting	13,396,416	1,179,334	8.80%	934,463	6.98%	2.025%
TOTAL ULTIMATE CONSUMERS	676,762,012	57,805,075	8.54%	46,143,794	6.82%	100.00%
Miscellaneous Service Revenue	999,716	1,003,763		408.443		
Rent from Electric Property	1,957,235	(556.373)		(556,373)		
TOTAL JURISDICTIONAL	679,718,963	58,252,465	8.57%	45,995,864	6.77%	

Kentucky Utilities Company
Summary of Proposed Increase
Based on Sales for the 12 Months Ended September 30.2003

	Adjusted Billings at Current Rates	Increase	Percentage Increase
Residential Rate RS	$ 121,233,915	$ 6,943,465	
Full Electric Residential Service Rate FERS	131,265,061	13.122.981	
Comb. Off-Peak Water Heating Rate CWH - RS	226.880	66.404	
Comb. Off-Peak Water Heating Rate CWH - FERS	184,889	61.127	
Total Residential	252.910,745	20.193.976	7.98%
General Service Rate GS - Secondary	63,054,553	4,464,741	
General Service Rate GS - Primary	2,543,978	233.163	
Comb. Off-Peak Water Heating Rate CWH - GS	2.434	798	
Electric Space Healing Rider - Rate 33	668.126	234,469	
Total General Service	66,269,093	4,933,172	7.44%
All Electric School Service Rate AES	3,955,546	294,587	7.45%
Combined Lighting 8 Power Service Rate LP - Secondary	155,582,998	12,488,035	
Combined Lighting 8 Power Service Rate LP - Primary	35,121,687	1.919.971	
Combined Lighting 8 Power Service Rate LP - Transmission	805.361	44,566	
Water Pumping Service Rate M	723,351	45,644	
High Load Factor Rate HLF Primary	22,475,293	1,496,550	
High Load Factor Rate HLF Secondary	12,248,660	913.296	
Total Combined Lighting & Power Service	226,957,349	16,908,062	7.45%
Large Comm./Industrial Time-of-Day Rate LCI-TOD Primary	65,546,566	1,621,297	
Large Comm./Industrial Time-of-Day Rate LCI-TOD Transmission	18,589,204	427.638	
Total Comm/Industrial Time-of-Day	84,135,770	2,048,936	2.44%
Coal Mining Power Service Rate MP Transmission	3,748,239	285.069	
Coal Mining Power Service Rate MP Primary	4,793,968	353.120	
Total Coal Mining Power Service	8,542,207	638.188	7.47%
Large Mine Power Time-of-Day Rate LMP-TOD Primary	1,944,714	148.303	
Large Mine Power Time-of-Day Rate LMP-TOD Transmission	4 098.693	305,159	
Total Large Mine Power Time-of-Day	6,043 407	453,462	7.50%
Special Contract	14,551,478	(261,052)	-1.79%
Street Lighting Service Rate St. Lt.	5,402,425	376,225	
Decorative Street Lighting Service Rate Dec. St. Lt.	807,559	56,815	
Private Outdoor Lighting Service Rate P.O. Lt.	6,293,269	438.616	
Customer Outdoor Lighting Service Rate C. O. Lt.	693,164	60.807	
Total Private Outdoor Lighting	13,396,416	934.463	6.98%
TOTAL ULTIMATE CONSUMERS	$ 676,762,012	$ 46,143,794	6.82%
Miscellaneous Service Revenue	999.716	408.443	
Rent from Electric Property	1,957,235	(556.373)	
TOTAL JURISDICTIONAL	679,718,963	45,995,864	6.77%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBEF 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
RS - Rate Codes 010,050						
Customer Charges '(a)	2,708,953		$ 2.82	$ 7,639,247	$ 5.00	$ 13,544,765
First 100 KWH		260,463,182	$ 0.05017	13,067,438	$ 0.04404	11,470,799
Next 300 KWH		718,054,152	$ 0.04572	32,829,436	$ 0.04404	31,623,105
Next 600 KWH		913,350,525	$ 0.04172	38,104,984	$ 0.04404	40,223,957
Excess KWH		752,270,308	$ 0.04172	31,384,717	$ 0.04404	33,129,984
Sub-Total		2,644,138,167		$ 115,386,575		$ 116,447,845
Total Calculated at Base Rates				$ 123,025,822		$ 129.992.610
Correction Factor				0.999957		0.999957
Total After Application of Correction Factor				$ 123,031,152		$ 129,998,242
Fuel Clause Billings - proforma for rollin				1,946,159		1,946,159
Merger Surcredit				(2,974,607)		(2,974,607)
Value Delivery Surcredit				(367,155)		(367,155)
VDT Amortization & Surcredit Adjustment				15,547		15,547
Adjustment to Reflect Year-End Customers				(417,181)		(440.805)
Total Rate RS				$ 121,233,915		$ 128,177,380
Proposed Increase						6,943,465
Percentage Increase						5.73%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
CWH -Rate Code 120, RS						
Customer Charges '(a)	51,243		$ 1.03	$ 52,780		$
First 100 KWH		4,042,164	$ 0.02665	107,724	$ 0.04404	178,017
Next 300 KWH		2,852,289	$ 0.02665	76,013	$ 0.04404	125,615
Next 600 KWH		193,230	$ 0.02665	5,150	$ 0.04404	8,510
Excess KWH		0	$ 0.02665		$ 0.04404	
Subtotal		7,087,683		$ 188,887		$ 312,142
Total Calculated at Base Rates				$ 241,667		$ 312,142
Correction Factor				0.999750		0.999750
Total After Application of Correction Factor				$ 241,727		$ 312,220
Fuel Clause Billings - proforma for rollin				5,535		5,535
Merger Surcredit				(5,712)		(5,712)
Value Delivery Surcredit				(679)		(679)
VDT Amortization & Surcredit Adjustment				29		29'
Adjustment to Reflect Year-End Customers				(14,020)		(18,108)
Total Rate CWH / RS				$ 226,880		$ 293,284
Proposed Increase						66,404
Percentage Increase						29.27%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
FERS - Rate Codes 020,060,080						
Customer Charges "(a)	1,983,477		$ 3.85	$ 7,636,386	$ 5.00	$ 9,917,385
First 1,000 KWH		1,686,402,755	$ 0.04229	71,317,973	$ 0.04404	74,269,177
Excess KWH		1,358,217,822	$ 0.03836	52,101,236	$ 0.04404	59,815,913
Sub-Total		3,044,620,577		$ 123,419,208		$ 134,085,090
Total Calculated at Base Rates				$ 131,055,595		$ 144,002,475
Correction Factor				0.999917		0.999917
Total After Application of Correction Factor				$ 131,066,473		$ 144,014,428
Fuel Clause Billings - proforma for rollin				1,905,058		1,905,058
Merger Surcredit				(3,110,470)		(3,110,470)
Value Delivery Surcredit				(383,963)		(383,963)
VDT Amortization & Surcredit Adjustment				16,258		16,258'
Adjustment to Reflect Year-End Customers				1,771,704		1,946,729
Total Rate FERS				$ 131,285,061		$ 144,386,041
Proposed Increase						13.1 22,981
Percentage Increase						10.00%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
CWH - Rate Codes **122** FERS						
Customer Charges "(a)	36,730		$ 1.03	$ 37.832	$ -	$ -
First 1,000 KWH		5,846,032	$ 0.02665	155,797	$ 0.04404	257,459
Excess KWH		0	$ 0.02665		$ 0.04404	
Sub-Total		5,846,032		$ 155,797		$ 257,459
Total Calculated at Base Rates				$ 193.629		$ 257,459
Correction Factor				0.999892		0.999892
Total After Application of Correction Factor				$ 193,650		$ 257,487
Fuel Clause Billings - proforma for rollin				4,573		4,573
Merger Surcredit				(4,584)		(4,584)
Value Delivery Surcredit				(550)		(550)
VDT Amortization & Surcredit Adjustment				23		23
Adjustment to Reflect Year-End Customers				(8,223)		(10,934)
Total Rate CWH / FERS				**$ 104,009**		**$ 246,016**
Proposed increase						**61,127**
Percentage Increase						33.06%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
GSS - Rate Codes 110, 113, 150, 153, 710						
Customer Charges '(a)	822,782		$ 4.11	$ 3,381,634	$ 10.00	$ 8,227,820
First 500 KWH		250,675,964	$ 0.06443	16,151,052	$ 0.05327	13,353,509
Next 1,500 KWH		340,305,160	$ 0.05332	18,145,071	$ 0.05327	18,128,056
Excess KWH		514,894,841	$ 0.04870	25,075,379	$ 0.05327	27,428,448
Sub-Total		1,105,875,966		$ 59,371,502		$ 58,910,013
Total Calculated at Bare Rates				$ 62,753,136		$ 67,137,833
Correction Factor				0.994771		0.994771
Total After Application of Correction Factor				$ 63,083,006		$ 67,490,751
Fuel Clause Billings - proforma for rollin				831,532		831,532
Merger Surcredit				(1,498,838)		(1,498,838)
Value Delivery Surcredit				(184,691)		(184,691)
VDT Amortization & Surcredit Adjustment				7,821		7,821
Adjustment to Reflect Year-End Customers				815,724		872,720
Total Rate GS Secondary				$ 63,054,553		$ 67,519,294
Proposed Increase						4,464,741
Percentage Increase						7.08%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
GSP - Rate Codes 111, 151						
Customer Charges "(a)	1,127		$ 4.11	$ 4,632	$ 10.00	$ 11,270
First 500 KWH		461,154	$ 0.06443	29,712	$ 0.05327	24,566
Next 1,500 KWH		1,168,955	$ 0.05332	62,329	$ 0.05327	62,270
Excess KWH		50,497,087	$ 0.04870	2,459,208	$ 0.05327	2,689,980
Sub-Total		52,127,196		$ 2,551,249		$ 2,776,816
Primary Service Discounts				(142,440)		(155,381)
Minimum Billings				156,810		171,057
Total Calculated at Base Rates				$ 2,570,251		$ 2,803,762
Correction Factor				1.001490		1.001490
Total After Application of Correction Factor				$ 2,566,427		$ 2,799,590
Fuel Clause Billings - proforma for rollin				45,451		45,451
Merger Surcredit				(61,024)		(61,024)
Value Delivery Surcredit				(7,181)		(7,181)
VDT Amortization & Surcredit Adjustment				304		304
Adjustment to Reflect Year-End Customers				-		
Total Rate GS Primary				$ 2,543,978		$ 2,777,141
Proposed Increase						233,163
Percentage Increase						9.17%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
CWH - Rate Codes 126 GS						
Customer Charges '(a)	901		$ 1.03	$ 928		$
First 500 KWH		68,163	$ 0.02665	1,817	$ 0.05327	3,631
Next 1,500 KWH		342	$ 0.02665	9	$ 0.05327	18
Excess KWH		0	$ 0.02665		$ 0.05327	
Sub-Total		66,505		$ 1,826		$ 3,649
Total Calculated at Base Rates				$ 2,754		$ 3,649
Correction Factor				1.000019		1.000019
Total After Application of Correction Factor				$ 2,754		$ 3,649
Fuel Clause Billings - proforma for rollin				51		51
Merger Surcredit				(64)		(64)
Value Delivery Surcredit				(7)		(7)
VDT Amortization & Surcredit Adjustment				0		0
Adjustment to Reflect Year-End Customers				(299)		(396)
Total Rate CWH / GS				$ 2,434		$ 3,233
Proposed Increase						798
Percentage Increase						32.79%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
33 - Rate Code 330 GS						
Customer Charges *(a)	11,530		$ -	$	$ -	$
First 500 KWH		3,040,894	$ 0.03926	119,385	$ 0.05327	161,988
Next 1,500 KWH		4,522,308	$ 0.03926	177,546	$ 0.05327	240,903
Excess KWH		9,709,702	$ 0.03926	381,203	$ 0.05327	517,236
Sub-Total		17,272,904		$ 678,134		$ 920,128
Minimum Billings				23,562		23,562
Total Calculated at Base Rates				$ 701,696		$ 943,690
Correction Factor				1.002812		1.002812
Total After Application of Correction Factor				$ 699,728		$ 941,043
Fuel Clause Billings - proforma for rollin				6,006		6,006
Merger Surcredit				(15,915)		(15,915)
Value Delivery Surcredit				(1,924)		(1,924)
VDT Amortization & Surcredit Adjustment				81		81
Adjustment to Reflect Year-End Customers				(19,849)		(26,694)
Total Rate 33				$ 668,128		$ 902,598
Proposed Increase						234,469
Percentage Increase						35.09%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPS/AES - Rate Coda 220						
Number of Customers	3.474					
Demand	367,906		$ -	$	$ -	$
First 500,000 KWH		100,707,601	$ 0.03936	3,963,851	$ 0.04227	4,256,910
Next 1,500,000 KWH		0	$ 0.03936		$ 0.04227	
Excess KWH		0	$ 0.03936		$ 0.04227	
Sub-Total		100,707,601		$ 3,963,851		$ 4,256,910
Minimum Billings				6,022		6,022
Total Calculated at Base Rates				$ 3.969.873		5 4,262,932
Correction Factor				0.994813		0.994813
Total **After** Application of Correction Factor				$ 3,990,570		$ 4,285,158
Fuel Clause Billings - proforma for rollin				70,235		70,235
Merger Surcredit				(94,157)		(94,157)
Value Delivery Surcredit				(11,594)		(11,594)
VDT Amortization & Surcredit Adjustment				491		491
Adjustment to Reflect Year-End Customers						
Total Rate AES				$ 3,955,546		$ 4,250,133
Proposed Increase						294,587
Percentage Increase						7.45%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPS - Rate Codes 562,568						
Number of Customers	154,715				$ 75.00	$ 11,603,625
Demand	10,678,854		$ 4.11	$ 43,890,092	$ 6.65	71,014,382
Minimum Annual Charges				136,444		220,767
First 500,000 KWH		3,874,329,937	$ 0.02872	111,270,756	$ 0.02200	85,235,259
Next 1,500,000 KWH		61,080,231	$ 0.02633	1,608,242	$ 0.02200	1,343,765
Excess KWH		0	$ 0.02504		$ 0.02200	
Sub-Total		3,935,410,168		$ 112,878,998		$ 86,579,024
Total Calculated at Base Rates				$ 156,905,534		$ 169,417,797
Correction Factor				0.998130		0.998130
Total After Application of Correction Factor				$ 157,199,484		$ 169,735,188
Fuel Clause Billings - proforma for rollin				3,170,805		3,170,805
Merger Surcredit				(3,748,979)		(3,748,979)
Value Delivery Surcredit				(460,016)		(460,016)
VDT Amortization & Surcredit Adjustment				19,479		19,479
Adjustment to Reflect Year-End Customers				(597,774)		(645,443)
Total Rate LP Secondary				$ **155,582,998**		**$ 168,071,034**
Proposed Increase						**12,488,035**
Percentage Increase						8.03%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPP - Rate Codes **561,566**						
Number of Customers	3,656				$ 75.00	$ 274,200
Demand	2,381,439		$ 3.13	$ 7,453,905	$ 6.26	14,907,810
CSR Credits	43,289		$ (3.20)	(138,526)	$ (3.20)	(138,526)
CSR Penalties				2,411		2,411
First 500,000 KWH		639,927,383	$ 0.02872	18,378,714	$ 0.02200	14,078,402
Next 1,500,000 KWH		331,775,188	$ 0.02633	8,735,641	$ 0.02200	7,299,054
Excess KWH		26,286,146	$ 0.02504	658,205	$ 0.02200	578,295
Sub-Total		997,988,716		$ 27,772,560		$ 21,955,752
Total Calculated at Base Rates				$ 35,090,351		$ 37,001,647
Correction Factor				0.998820		0.998820
Total After Application of Correction Factor				$ 35,131,814		$ 37,045,369
Fuel Clause Billings - proforma for rollin				814,739		814,739
Merger Surcredit				(843,553)		(843,553)
Value Delivery Surcredit				(103,491)		(103,491)
VDT Amortization & Surcredit Adjustment				4,382		4,382
Adjustment to Reflect Year-End Customers				117,795		124,211
Total Rate **LP** Primary				**$ 35,121,687**		**$ 37,041,656**
Proposed Increase						**1,919,971**
Percentage Increase						5.47%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPT - Rate Codes 560,567						
Number of Customers	27				$ 75.00	$ 2,025
Demand	36.408		$ 2.97	$ 108.133	$ 5.92	215,538
Minimum Annual Charges				1,522		3,034
First 500,000 KWH		6,109,950	$ 0.02872	175,478	$ 0.02200	134,419
Next 1.500.000 KWH		9,366,902	$ 0.02633	246,631	$ 0.02200	206,072
Excess KWH		0	$ 0.02504		$ 0.02200	
Sub-Total		15,476,852		$ 422,108		$ 340,491
Total Calculated at Base Rates				$ 531,763		$ 561.087
Correction Factor				0.993946		0.993946
Total Afler Application of Correction Factor				$ 535,002		$ 564,505
Fuel Clause Billings - proforma for rollin				11,436		11,436
Merger Surcredit				(12,742)'		(12,742)
Value Delivery Surcredit				(1,567)		(1,567)
VDT Amortization & Surcredit Adjustment				66'		66
Adjustment to Reflect Year-End Customers				273,166		288,230
Total Rate LP Transmission				$ **805,361**		$ **849,927**
Proposed Increase						**44,566**
Percentage Increase						5.53%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LCIP - Rate Code 563						
Number of Customers	315				$ 120.00	$ 37.800
On-Peak Demand	4,068,204		$ 4.14	$ 16,842,364	$ 4.58	18,632,374
Off-Peak Demand	3,969,563		$ 0.73	$ 2,897,781	$ 0.73	2,897,781
CSR Credits	64.834		$ (3.20)	$ (207,469)	$ (3.20)	(207,469)
Penalties				21,553		21,553
Energy		2,080374,735	$ 0.02210	45,987,332	$ 0.02200	45,779,244
Total Calculated at Base Rates				$ 65,541,561		$ 67,161,283
Correction Factor				0.999029		0.999029
Total After Application of Correction Factor				$ 65,605,294		$ 67,226,592
Fuel Clause Billings - proforma for rollin				1,698,726		1,698,726
Merger Surcredit				(1,573,353)		(1,573,353)
Value Delivery Surcredit				(192,241)		(192,241)
VDT Amortization & Surcredit Adjustment				8,140		8,140
Adjustment to Reflect Year-End Customers						
Total Rate LCI Primary				$ 65,546,566		$ 67,167,863
Proposed Increase						1,621,297
Percentage increase						2.47%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
EASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)		(5)	(6)		(7)
	Bills / KW	Total KWH		Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)		Settlement Rates	Calculated Revenue @ Proposed Rates
LCIT - Rate Code 564								
Number of Customers	48					$	120.00	$ 5,760
On-Peak Demand	1,099,952		$	3.95	$ 4,344,810	$	4.39	4,828,789
Off-Peak Demand	1,092,494		$	0.73	797.521	$	0.73	797,521
CSR Credits	122.014		$	(3.10)	(378,243)	$	(3.10)	(378,243)
Penalties					76,807			76,807
Energy		621,047,926	$	0.02210	13,725,159	$	0.02200	13,663,054
Total Calculated at Base Rates					$ 18,566,054			$ 18,993,688
Correction Factor					0.999990			0.999990
Total After Application of Correction Factor					$ 18,566,238			$ 18,993,876
Fuel Clause Billings - proforma for rollin					526,690			526,690
Merger Surcredit					(450,942)			(450,942)
Value Delivery Surcredlt					(55,1 17)			(55,117)
VDT Amortization & Surcredit Adjustment					2,334			2,334
Adjustment to Reflect Year-End Customers								
Total Rate LCI Transmission					$ 18,589,204			$ 19,016,842
Proposed Increase								427,630
Percentage Increase								2.30%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
HLFP - Rate Code 571						
Number of Customers	529				$ 75.00	$ 39,675
Demand	1,345,913		$ 4.79	$ 6,446,922	$ 6.26	8,425,414
Energy		723,323,088	$ 0.02270	16,419,434	$ 0.02200	15,913.108
Minimum Billings				38,375		50,151
Total Calculated at Base Rates				$ 22.904.731		$ 24.428.349
Correction Factor				0.994328		0.994328
Total After Application of Correction Factor				$ 23,035,385		$ 24,567,694
Fuel Clause Billings - proforma for rollin				591,757		591,757
Merger Surcredit				(550,321)		(550,321)
Value Delivery Surcredit				(66,795)		(66,795)
VDT Amortization & Surcredit Adjustment				2,828		2,828
Adjustment to Reflect Year-End Customers				(537,561)		(573,319)
Total Rate HLF Primary				$ **22,475,293**		**$ 23,971,843**
Proposed Increase						**1,496,550**
Percentage Increase						6.66%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
HLFS - Rate Code 572						
Number of Customers	494				$ 75.00	$ 37,050
Demand	705,460		$ 5.13	$ 3,619,007	$ 6.65	4,691,306
Energy		370,430,550	$ 0.02270	8,408,773	$ 0.02200	8,149,472
Minimum Billings				203,871		264,277
Total Calculated at Base Rates				$ 12,231,651		5 13,142,105
Correction Factor				0.996888		0.996888
Total After Application of Correctlon Factor				$ 12,269,841		$ 13,183,137
Fuel Clause Billings - proforma for rollin				305,857		305,857
Merger Surcredit				(292,805)		(292,805)
Value Delivery Surcredit				(35,747)		(35,747)
VDT Amortization & Surcredit Adjustment				1,514,		1,514
Adjustment to Reflect Year-End Customers						-
Total Rate HLF Secondary				5 12,248,660		$ 13,161,955
Proposed Increase						913.296
Percentage Increase						7.46%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Rate M - Rate Code 650						
Customer Charges '(a)	1,151		$ 10.27	$ 11,821	$ 75.00	$ 86,325
Demand Charges	46,351.6		$ -	$	$ 6.65	$ 308,238
First 10,000 KWH		6.1 36,374	$ 0.04631	284.175	$ 0.02200	135,000
Excess KWH		10,959,266	$ 0.03917	429,274	$ 0.02200	241,104
Sub-Total		17,095,640		$ 713,450		$ 376,104
Total Calculated at Base Rates				$ 725,271		$ 770,667
Correction Factor				0.994581		0.994581
Total After Application of correction Factor				$ 729,223		$ 774,866
Fuel Clause Billings - proforma for rollin				13,459		13,459
Merger Surcredit				(17,302)		(17,302)
Value Delivery Surcredit				(2,118)		(2,118)
VDT Amortization & Surcredit Adjustment				90'		90
Adjustment to Reflect Year-End Customers						
Total Rate M Water Pumping				$ 723,351		$ 768,995
Proposed Increase						45,644
Percentage Increase						6.31%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
EASED ON SALES FOR THE **12** MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
MPT - Rate Codes **680,687**						
Number of Customers	183				$ 75.00	$ 13,725
Demand	335,459		$ 2.67	$ 895.675	$ 4.57	1,533,046
First 500,000 KWH		55,158,510	$ 0.02881	1,589.117	$ 0.02400	1,323,804
Excess KWH		59,532,090	$ 0.02540	1,512,115	$ 0.02400	1,428,770
Sub-Total		114,690,600		$ 3,101,232		$ 2,752.574
Total Calculated at Base Rates				$ 3,996,906		$ 4,299,346
Correction Factor				0.988697		0.988697
Total After Application of **Correction** Factor				$ 4,042,601		$ 4,348,498
Fuel Clause Billings - proforma for rollin				87.711		87,711
Merger Surcredit				(95,856)		(95,656)
Value Delivery Surcredit				(11,653)		(11,653)
VDT Amortization & Surcredit Adjustment				493		493
Adjustment to Reflect Year-End Customers				(275,257)		(296,085)
Total Rate MP **Transmission**				**$ 3,746,239**		**$ 4,033,308**
Proposed Increase						**285,069**
Percentage Increase						7.61%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
MPP - Rate Codes 681,686						
Number of Customers	261				$ 75.00	$ 19,575
Demand	473.781		$ 3.01	$ 1,428,082	$ 4.69	2,222,034
First 500,000 KWH		89,036,933	$ 0.02881	2,565,154	$ 0.02400	2,136,886
Excess KWH		38,740,167	$ 0.02540	984,000	$ 0.02400	929,764
Sub-Total		127,777,100		$ 3,549,154		$ 3,086,650
Minimum Annual Charges				64,223		100,068
Total Calculated at Base Rates				$ 5,039,459		$ 5,408,328
Correction Factor				0.996149		0.996149
Total After Application of Correction Factor				$ 5,058,939		$ 5,429,234
Fuel Clause Billings - proforma for rollin				103.480		103,480
Merger Surcredit				(119,812)		(119.8121
Value Delivery Surcredit				(14,613)		(14,813)
VDT Amortization & Surcredit Adjustment				619'		619
Adjustment to Reflect Year-End Customers				(234,645)		(251,820)
Total Rate MP Primary				$ 4,793,968		$ 5,147,088
Proposed Increase						353,120
Percentage Increase						7.37%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement 'Rates	Calculated Revenue @ Proposed Rates
LMPP - Rate Code 683						
Number of Customers	25				$ 120.00	$ 3,000
On-Peak Demand	160,687		$ 4.14	$ 665,243	$ 5.39	866,102
Off-Peak Demand	160,665		$ 0.73	117,266	$ 0.73	117,286
Energy		56,287,872	$ 0.02094	1,178,668	$ 0.02000	1,125,757
Minimum Annual Billings				(8,760)		(11,405)
Total Calculated at Base Rates				$ 1,952,437		$ 2,100,740
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 1,952,437		$ 2,100,740
Fuel Clause Billings - proforma for rollin				43.817		43,817
Merger Surcredit				(46,196)		(46,196)
Value Delivery Surcredit				(5,581)		(5,581)
VDT Amortization & Surcredit Adjustment				236		236
Adjustment to Reflect Year-End Customers						
Total Rate LMP Primary				**$ 1,944,714**		**$ 2,093,017**
Proposed Increase						**148,303**
Percentage Increase						7.63%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LMPT - Rate Code 664						
Number of Customers	82				$ 120.00	$ 9,840
On-Peak Demand	400,744		$ 3.80	$ 1,522,827	$ 4.85	1,943,608
Off-Peak Demand	381,990		$ 0.73	278,853	$ 0.73	278,853
Energy		135,342,000	$ 0.02094	2,834,061	$ 0.02000	2,706,840
Minimum Annual Billings				197,968		252,670
Total Calculated at Base Rates				$ 4,833,710		$ 5,191,811
Correction Factor				1.002250		1.002250
Total Afler Application of Correction Factor				$ 4,822,860		$ 5,180,158
Fuel Clause Billings - proforma for rollin				106,921		106,921
Merger Surcredit				(114,208)		(114,208)
Value Delivery Surcredit				(13,680)		(13,680)
VDT Amortization & Surcredit Adjustment				579'		579
Adjustment to Reflect Year-End Customers				(703,778)		(755,917)
Total Rate LMP Transmission				$ 4,098,693		$ 4,403,852
Proposed Increase						305,159
Percentage Increase						7.45%
Total LMP				$ 6,043,407		$ 6,496,869
Proposed Increase						453.462
Percentage Increase						7.50%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Special Contract - Rate Code 720						
Non-Interruptible Demand	408,840		$ 3.89	$ 1,590,387	$ 3.98	$ 1,627,182
Interruptible Demand			$ 1.86		$ 1.95	
Energy		256,027,222	$ 0.02148	5,499,465	$ 0.02200	5,632,599
Total Calculated at Base Rates				$ 7,089,852		$ 7,259,781
Correction Factor				1.000241		1.000241
Total After Application of Correction Factor				$ 7,088,146		$ 7,258,034
Fuel Clause Billings - proforma for rollin				206.387		206.387
Merger Surcredit				(170,246)		(170,246)
Value Delivery Surcredit				(20,695)		(20,695)
VDT Amortization & Surcredit Adjustment				876		876
Adjustment to Reflect Year-End Customers						
Total WestVaCo Special Contract				**$ 7,104,468**		**$ 7,274,357**
Proposed Increase						**169,889**
Percentage increase						2.39%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KVA *KW*	Total KWH	Present Rates	Calculated Revenue @ Present NCL Rate (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Special Contract Billing Code 723,724,725,726						
Non-Interruptible/On-Peak Deme	962,182		$ 5.58	$ 5,368,976	$ 4.39	$ 4,223,979
Interruptible/Off-Peak Demand	987,308		$ 1.03	$ 1,016,927	$ 0.73	$ 720,735
CSR Credit	887,629		$ (3.10)	$ (2,751,649)	$ (3.10)	$ (2,751,649)
Energy		224,499,600	$ 0.01750	3,928,743	5 0.02200	4,938,991
Total Calculated at Base Rates				$ 7,562,997		$ 7,132,056
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 7,562,997		$ 7,132,057
Fuel Clause Billings - proforma for rollin				200,577		200,577
Merger Surcredit				(283,568)		(283,568)
Value Delivery Surcredit				(34,456)		(34,456)
VDT Amortization & Surcredit Adjustment				1,459		1,459
Adjustment to Reflect Year-End Customers						
Total NAS Special Contract				$ 7,447,010		$ 7,016,069
Proposed increase						(430,941)
Percentage Increase						-5.79%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
FWP - Rate Code 740 *(c)						
Energy		0	$ 0.03598		$ 0.03598	
Total Calculated at Base Rates						
Correction Factor						
Total After Application of Correction Factor						
INCREASE IN BASE RATES REVENUE						

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Street Lighting	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates	Settlement Rates	Calculated Revenue @ Proposed Rates
Incandescent Street Lighting (1)				(see Exhibit 9)		
I-1000-std	42,730	1,203	$ 2.11	$ 2,538	$ 2.26	$ 2,719
I-2500-std	1,293,398	18,532	$ 2.57	47,627	$ 2.75	50,963
I-4000-std	768.860	7,034	$ 3.68	25,885	$ 3.94	27,714
I-6000-std	12,762	84	$ 4.89	411	$ 5.24	440
I-10000-std	0	0	$ 6.57		$ 7.03	
I-1000-orn	0	0	$ 2.72		$ 2.91	
I-2500-orn	6,432	96	$ 3.32	319	$ 3.55	341
I-4000-orn	58,859	540	$ 4.56	2,462	$ 4.88	2,635
I-6000-orn	7,152	48	$ 5.07	282	$ 6.29	302
I-10000-orn	0	0	$ 8.07		$ 8.64	
Mercury Vapor Street Lighting						
MV-3500-std	0	0	$ 5.36		$ 6.60	
MV-7000-std	1,199,867	17,126	$ 6.19	106,010	$ 6.63	113,545
MV-10000-std	1,220,047	12,442	$ 7.14	88.836	$ 7.64	95,057
MV-20000-std	3,216,852	20,879	$ 8.39	175,175	$ 8.98	187,493
MV-3500-orn	0	0	$ 7.60		$ 8.14	
MV-7000-orn	102,988	1,492	$ 8.30	12,384	$ 8.89	13,264
MV-10000-orn	674,672	6,882	$ 9.01	62,007	$ 9.65	66,411
MV-20000-orn	2,851,854	18,790	$ 9.89	185,833	$ 10.59	198,986

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Street Lighting -continued	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates	Settlement Rates	Calculated Revenue @ Proposed Rates
High Pressure Sodium Street Lighting				(see Exhibit 9)		
HPS-4000-std	1,706,461	84.016	$ 4.68	393,195	$ 5.00	420.080
HPS-5800-std	2,821,602	97,770	$ 5.08	496.672	$ 5.43	530.891
HPS-9500-std	8,471,266	211,989	$ 5.72	1,212,577	$ 6.11	1,295,253
HPS-22000-std	4,975,937	60,024	$ 8.44	506,603	$ 9.02	541,416
HPS-50000-std	1,435,313	8,864	$ 13.62	120,728	$ 14.55	128,971
HPS-4000-orn	953,042	47,651	$ 7.13	339,752	$ 7.62	363,101
HPS-5800-orn	2,927,333	105,857	$ 7.53	797,103	$ 8.04	851,090
HPS-9500-orn	1,092,981	27,793	$ 8.35	232,072	$ 8.92	247,914
HPS-22000-orn	3,822,835	47,250	$ 11.06	522,585	$ 11.81	558,023
HPS-50000-orn	827,689	5,095	$ 16.23	82,692	$ 17.34	88.347
Sub-Total	40,490,932	801,457		$ 5,413,746		$ 5,784,957
Partial Month billings				86,450		92,378
Total Calculated at Base Rates				$ 5,500,195		$ 5,877,334
Correction Factor				1.000190		1.000190
Total After Application of Correction Factor				$ 5,499,149		$ 5,876,216
Fuel Clause Billings - proforma for rollin				30,519		30,519
Merger Surcredit				(129,056)		(129,056)
Value Delivery Surcredit				(15,744)		(15,744)
Adjustment to Reflect Year-End Customers				16.889		18.047
VDT Amortization & Surcredit Adjustment				667		667
Total Rate St. Lt.				$ 5,402,425		$ 5,780,650
Proposed increase						378,225

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Street Lighting-- Decorative						
HPS-A-4000-Dec	0	0	$ 9.74	$	$ 10.40	$
HPS-A-5800-Dec	1,992	72	$ 10.24	737	$ 10.94	788
HPS-A-9500-Dec	48,347	1,231	$ 10.87	13,381	$ 11.61	14,292
HPS-A-4000-His	29,279	1,464	$ 15.28	22,370	$ 16.32	23,892
HPS-A-5800-His	11,621	420	$ 15.77	6.623	$ 16.85	7,077
HPS-A-9500-His	144,939	3,677	$ 16.41	60,340	$ 17.53	64,458
HPS-4000 col	130,976	6,556	$ 6.42	42,090	$ 6.86	44,974
HPS-5800 col	174,991	6,208	$ 6.83	42.401	$ 7.30	45,318
HPS-9500 col	371,159	9,455	$ 7.40	69,967	$ 7.90	74,695
HPS-5800 coa	0	0				
HPS-9500 coa	0	0				
HPS-5800 con	634,990	22,944	$ 11.80	270,739	$ 12.60	289.094
HPS-9500 con	173,631	4,452	$ 14.05	62,551	$ 15.01	66.825
HPS-22000 con	268,604	3,329	$ 16.29	54,229	$ 17.40	57,925
HPS-50000 can	157,439	939	$ 21.09	19,804	$ 22.53	21,156
HPS-16000 Granville	3,611	63	$ 44.60	2,810	$ 47.64	3,001
HPS-16000 Granville A	83.872	1,666	$ 35.84	59,709'	$ 38.28	63,774
HPS-16000 Granville B	12,666	256	$ 58.78	15,048	$ 62.79	16,074
HPS-16000 Granville C	19,859	399	$ 39.50	15,761	$ 42.19	16,834
HPS-16000 Granville D	2,103	45	$ 41.12	1,850	$ 44.92	2,021
HPS-16000 Granville E	649	13	$ 42.24	549	$ 46.14	600
HPS-16000 Granville F	3,500	70	$ 56.94	3,986	$ 62.21	4,355
HPS-16000 Granville G	6,093	122	$ 55.32	6,749	$ 59.09	7,209
HPS-16000 Granville H	0	0	$ 40.70		$ 44.48	
HPS-16000 Granville I	1,296	26	$ 36.96	961	$ 40.38	1,050
HPS-16000 Granville A1	8,946	179	$ 51.66	9,247	$ 55.18	9,877
HPS-16000 Granville B1	0	0	$ 74.60		$ 79.69	
HPS-16000 Granville E I	649	13	$ 58.06	755	$ 63.43	825

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER), 2003

(1)	)	(:	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Street Lighting -- Decorative - continued						
HPS-16000 Granville A2	7,930	160	$ 51.66	8,266	$ 55.18	8.829
HPS-16000 Granville 83	2,101	42	$ 52.78	2,217	$ 56.38	2.368
HPS-16000 Granville G I	1,190	24	$ 55.32	1,328	$ 59.09	1,418
HPS-16000 Granville 82	11,773	236	$ 53.92	12,725	$ 58.91	13,903
Sub-Total	2,314,206	64,061		$ 807,191		$ 862.631
Partial Month billings				6,975		7,454
Total Calculated at Base Rates				$ 814,165		$ 870.085
Correction Factor				0.999016		0.999016
Total After Application of Correction Factor			141,960	$ 814,967		$ 870,942
Fuel Clause Billings - proforma for rollin				1,736		1,736
Merger Surcredit				(19,076)		(19,076)
Value Delivery Surcredit				(2,409)		(2.409)
Adjustment to Reflect Year-End Customers				12,240'		13.081
VDT Amortization & Surcredit Adjustment				102		102
Total Rate Dec St. Lt.				$ 807,559		$ 864,374
Proposed Increase						**56,815**

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Private Outdoor Lighting						
Standard (Served Overhead)						
MV-7000-OB	2,542,058	36,524	$ 7.12	$ 260,051	$ 7.61	$ 277,948
MV-20000-Cobr	1,214,151	8,012	$ 8.41	67,381	$ 8.98	11,948
HPS-5800-OB	70,769	2,534	$ 4.05	10,263	$ 4.33	10,972
HPS-9500-OB	13,810,099	350.344	$ 4.62	1,618,589	$ 4.94	1,730,699
HPS-22000-Cobr	1,268,099	15,631	$ 8.44	131,926	$ 9.02	140,992
HPS-50000-Cobr	4,403,511	27,021	$ 13.62	368,026	$ 14.55	393,156
Directional (Served Overhead)						
HPS-9500	4,431,410	112,584	$ 5.60	630,470	$ 5.98	673,252
HPS-22000	5,191,668	64,058	$ 7.93	507,980	$ 8.47	542,571
HPS-50000	13,251,698	81,371	$ 12.08	982,962	$ 12.90	1,049,686
Decorative (Served Underground)						
HPS-4000 coa decr	'478	24	$ 9.74	234	$ 10.40	250
HPS-5800 coa decr	3,464	120	$ 10.24	1,229	$ 10.94	1,313
HPS-9500 coa decr	76,594	1,961	$ 10.88	21,336	$ 11.62	22,787
HPS-4000 coa hist	19,923	996	$ 15.28	15.219	$ 16.32	16,255
HPS-5800 coa hist	11,318	410	$ 15.77	6,466	$ 16.85	6,909
HPS-9500 coa hist	222,699	5,706	$ 16.42	93,693	$ 17.54	100,083
HPS-5800 coa	0	0	$ 23.47		$ 25.07	
HPS-9500 coa	64,116	1,644	$ 24.09	39,604	$ 25.73	42,300
HPS-4000 col	12,719	636	$ 6.42	4,083	$ 6.86	4,363
HPS-5800 col	35,199	1,272	$ 6.83	8,688	$ 7.30	9,286
HPS-9500 col	509,423	13,046	$ 7.40	96,540	$ 7.90	103,063
HPS-5800 con	16,935	612	$ 11.80	7,222	$ 12.60	7.711
HPS-9500 con	90,992	2,341	$ 14.05	32,891	$ 15.01	35,138
HPS-22000 con	546,476	6,756	$ 16.29	110,055	$ 17.40	117,554
HPS-50000 con	1,624,326	10,033	$ 21.09	211,596	$ 22.53	226,043

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBEI 30,2003

(1)	(2) KWH	(3) Total Lights		(4) Present Rates		(5) Calculated Revenue @ Present Rates		(6) Settlement Rates		(7) Calculated Revenue @ Proposed Rates
Private Outdoor Lighting - continued						(see Exhibit 9)				
Metal Halide Directional										
MH-12000	209,687	3,026	$	8.27		25,025	$	8.83		26,720
MH-12000-WP	47,049	679	$	10.10		6,858	$	10.79		7.326
MH-12000-MP	3,328	48	$	16.10		773	$	17.20		826
MH-32000	3,174,956	21,013	$	11.46		240,809	$	12.24		257,199
MH-32000-WP	759,074	5,025	$	13.30		66,833	$	14.21		71,405
MH-32000-MP	162,468	1,085	$	19.29		20,930	$	20.81		22,362
MH-107800	5,180,248	14,272	$	23.67		337,818	$	25.28		360,796
MH-107800-WP	1,426,641	3,899	$	26.22		102,232	$	28.01		109,211
MH-107800-MP	290,486	806	$	31.50		25,389	$	33.65		27,122
Metal Halide Contemporary										
MH-12000-con	36,536	528	$	9.29		4,905	$	9.92		5,238
MH-12000-con-MP	121,818	1,764	$	17.13		30,217	$	18.30		32,281
MH-32000-con	306,662	2,035	$	12.90		26,252	$	13.78		28,042
MH-32000-con-MP	665,690	4,424	$	20.73		91,710	$	22.14		97,947
MH-107800-con	314,967	869	$	26.04		22,629	$	27.82		24,176
MH-107800-con-MP	694,079	1,925	$	33.88		65,219	$	36.19		69,666
Sub-Total	62,811,814	805,034			$	6,294,099			$	6,724,596
Partial Month billings						49,671				53,069
Total Calculated at Base Rates					$	6,343,770			$	6,777,664
Correction Factor						1.000377				1.000377
Total Afler Application of Correction Factor					$	6,341,376			$	6,775,107
Fuel Clause Billings - proforma for rollin						48,198				48,198
Merger Surcredit						(149,592)				(149,592)
Value Delivery Surcredit						(18,946)				(18,946)
VDT Amortization & Surcredit Adjustment						802				802
Adjustment to Reflect Year-End Customers						71,430				76,316
Total Rate P.O. Lt.					$	6,293,269			$	6,731,885
Proposed Increase										438,616

KENTUCKY UTILITIES COMPANY
ATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED)N SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates	Settlement Rates	Calculated Revenue @ Proposed Rates
Customer Outdoor Lighting				(see Exhibit 9)		
Inc-2500 (move to St. Lt) (1)	9,660	144	$ 5.12	$ 737	$ 7.61	$ 1,096
MV-3500 (move to St. Lt) (1)	20,097	478	$ 6.25	2,988	$ 7.61	3,638
MV-7000 (move to St. Lt.) (1)	8,411,057	120.910	$ 7.14	863,297	$ 7.61	920,125
Special Lighting	950,602	6,274	$ 6.16	38.648	$ 6.58	41,283
Speclai Lighting	359,447	2,218	$ 8.21	18,210	$ 8.77	19,452
Subtotal	9,750,863	130,024		$ 923.880		$ 985,593
Partial month billings				5,701		6,082
Total Calculated at Base Rates				$ 929,581		$ 991,675
Correction Factor				1.000087		1.000087
Total After Application of Correction Factor				$ 929,500		$ 991,589
Fuel Clause Billings - proforma for rollin				7,246		7,246
Merger Surcredit				(21,779)		(21,779)
Value Delivery Surcredit				(2,723)		(2,723)
VDT Amortization & Surcredit Adjustment				115		115
Adjustment to Reflect Year-End Customers				(19,194)		(20,476)
Total Rate C.O. Lt.				5 893,164		5 953,970
Proposed Increase						60.807

Louisville Gas and Electric Company
Summary of Settlement Electric Rate Increase by Rate Class
For the 12 months Ended September 30,2002

		Adjusted Billings at Current Rates		Proposed Increase In Revenue As Filed	Percentage Increase		Increase Per Settlement	Percentage increase	Percentage of Total
Residential	$	220,310,529	$	26,430,885	12.00%	$	18,708,395	8.49%	43.148%
General Service		83,504,883		8,978,115	10.75%		6,483,208	7.76%	14.952%
Large Commercial Rate LC		132,177,625		13,708,637	10.37%		10,242,386	7.75%	23.622%
Industrial Power Rate LP		100,837,138		10,100,134	10.02%		5,625,092	5.58%	12.973%
Special Contracts		28,070,944		3,028,038	10.79%		1,422,016	5.07%	3.280%
Street Lighting		11,678,144		1,386,185	11.87%		877,787	7.52%	2.024%
TOTAL ULTIMATE CONSUMERS	$	576,579,264	$	63,631,994	11.04%	$	43,358,883	7.52%	100.00%
Increase in Miscellaneous Charges		848,569		133,331			45,302		
TOTAL INCREASE IN REVENUE	$	577,427,833	$	63	11.04%	$	43,404,185	7.52%	

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF SETTLEMENT ELECTRIC RATE INCREASE BY RATE CLASS
BASED ON ADJUSTED SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
REVISED TO INCLUDE JANUARY 2004 ECR BASE RATES ROLLIN

Rate Class	Calculated Test Period Billings as Modified to Reflect Janaury 2004 ECR Rollin Rates	Settlement Increase in Revenue	Percentage Increase
Residential Rate R	$ 219,577,320		
Residential Water Heating	733,209.04		
Total Residential	220,310,529	$ 18,708,395	8.49%
General Service Rate GS	83,495,405		
Commercial Water Heating	9,479		
Total General Service	83,504,883	6,483,208	7.76%
Large Commercial Rate LC			
Primary	6,577,911		
Secondary	100,311,410		
Primary	10,683,797		
Secondary	14,604,508		
Total Rate LCTOD	132,177,625	10,242,386	7.75%
Industrial Power Rate LP			
Primary	4,567,163		
Secondary	25,929,168		
Transmission	11,530,567		
Primary	56,811,559		
Secondary	1,998,682		
Total Rate LPTOD	100,837,138	5,625,092	5.58%
Special Contracts			
Special Contracts	6,890,944		
Special Contracts			
Special Contracts	4,895,550		
Special Contracts	6,624,286		
Special Contracts	7,845,834		
Special Contracts	1,814,330		
Total Special Contracts	28,070,944	1,422,016	5.07%
Public Street Lighting Rate PSL	4,910,190		
Street Lighting Energy Rate SLE	142,487		
Outdoor Lighting Rate OL	6,066,969		
Traffic Lighting Rate TLE	558,499		
	11,678,144	877,787	7.52%
Total Ultimate Consumers	$ 576,579,264	$ 43,358,883	7.52%
Increase in Miscellaneous Charges	$ 715,238	$ 45,302	6.33%
Total Increase in Revenue	$ 577,294,502	$ 43,404,185	7.52%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
EASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
RESIDENTIAL RATE R						
Customer Charges	4,037,207		$ 3.40	$ 13,726,504	$ 5.00	$ 20,166,035
Energy Charges		kWh's				
First 600 kWh - Summer Season		704,635,241	$ 0.06149	43,328,021	$ 0.05867	41,481,877
Over 600 kWh - Summer Season		876,768,392	$ 0.06319	55,402,995	$ 0.05867	51,615,355
First 600 kWh - Winter Season		1,267,566,536	$ 0.05669	72,992,260	$ 0.05867	75,799,160
Over 600 kWh -Winter Season		973,572,745	$ 0.04370	42,545,129	$ 0.05687	57,314,227
Total Energy				214,268,405		226,210,619
Total Rate R @ base rates		3,842,544,916		$ 227,994,909		$ 246,396,654
RESIDENTIAL PREPAID METERING RPP						
Facilities Charges	5,462		$ 2.05	$ 11.197	$ 2.05	$ 11,197
Customer Charges	5,462		$ 3.40	16.571	$ 5.00	27.310
Energy Charges		kWh's 5,164,866	$ 0.05661	293,416	$ 0.05667	304,056
Total Prepaid Metering RPP @ base rates				$ 323.184		$ 342,563
Subtotal @ base rates before application of correction factor				$ 228,318,093		$ 246,739,217
Correction Factor -			1.002361		1.002361	
Subtotal @ base rates after application of Correction factor		3,847,709,782		$ 227,780,293		$ 246,158,026
Fuel Adjustment Clause. proforma for rollin				(1,499,234)		(1,499,234)
Merger Surcredit				(6,469,016)		(6,469,016)
Value Delivery Surcredit				(1,464,356)		(1,484,358)
VDT Amortization & Surcredit Adjustment				17,356		17,356
Adjustment to Reflect Year-End Customers		21,505,743		1,232,279		1,336,006
TOTAL RESIDENTIAL RATES R & RPP				I 219,577,320		I 238,058,781
PROPOSED INCREASE						$ 18,481,461
Percentage Increase						6.42%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
WATER HEATING RATE WH						
Residential Water **Heating**						
Customer Charges	73.228		$ 0.97	$ 71,031	$ -	$
Energy Charges		kWh's				
Summer Season		4,808,217	$ 0.04132	198.678	$ 0.05887	283.060
Winter Season		12,388,791	$ 0.04132	511.905	$ 0.05887	729.328
		17,197,008				
Total Residential Water Heating @ base rates		17,197,008		$ 781.612		$ 1,012,388
Commercial Water Heating						
Customer Charges	1.501		$ 0.97	$ 1,456	$ -	$
Energy Charges		kWh's				
Summer Season		67.741	$ 0.04132	2,799	$ 0.07086	4.800
Winter Season		141.564	$ 0.04132	5.849	$ 0.06313	8.937
		209,305				
Total Commercial Water Heating @ base rates		209,305		$ 10.104		$ 13,737
Subtotal @ base rates before application of correction factoi				I 791,716		$ **1,026,125**
Correction Factor -			1.003426		1.003426	
Subtotal @ base rates **after** application of correction factor		17,408,313		I 789,012		I **1,022,621**
Fuel Adjustment Clause - proforma for **rollin**				(10.373)		(10,373)
Merger Surcredit				(21.169)		(21.169)
Value Delivery Surcredit				(4,846)		(4,846)
VDT Amortization & Surcredit Adjustment				57		57
Adjustment to Reflect Year-End Customers		(229,190)		(9,993)		(13,095)
TOTAL WATER HEATING RATE WH				742.688		I 973,185
PROPOSED INCREASE						$ **230,507**
Percentage Increase						**31.04%**

LG&E Electric Exhibit 1
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LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
GENERAL SERVICE RATE GS						
Customer Charges - Sungle Phase	329,431		$ 4.02	$ 1,324,313	$ 10.00	$ 3,294,310
Customer Charges - Three Phase	156,788		$ 8.05	1,262,143	$ 15.00	2,351,820
Energy Charges		*kWh's*				
Summer Season		505,580,412	$ 0.06865	34,708,095	$ 0.070 6	35,825,428
Winter Season		799,975,176	$ 0.06092	48,734,488	$ 0.063 3	50,502,433
Total Energy				83,442,583		86,327,861
Primary Service Discounts				(27,354)		(29,245)
Total Rate GS @ base rates		1,305,555,588		$ 86,001,685		$ 91,944,746
SPACE HEATING RIDER TO RATE GS						
Customer Charges	9,221		$ 2.33	$ 21,485	$	$ -
Energy Charges		*kWh's*				
Summer Season			$ -	-	$ 0.07086	-
Winter Season		29,731,262	$ 0.04372	1,299,851	$ 0.06313	1,876,935
Total Space Heating Rider @ base rates		29,731,262		$ 1,321,336		$ 1,876,935
Subtotal @ base rates before application of correction factor				**$ 87,323,020**		**$ 93,821,681**
Correction Factor -			0.999589		0.999589	
Subtotal @ base rates after application of correction factor		1,335,286,850		**$ 87,358,902**		**$ 93,860,233**
Fuel Adjustment Clause - proforma for rollin				(621,080)		(621,080)
Merger Surcredit				(2,417,927)		(2,417,927)
Value Delivery Surcredit				(551,407)		(551,407)
VDT Amortization & Surcredit Adjustment				6,447		6,447
Adjustment to Reflect Year-End Customers		(4,415,970)		(279,531)		(301,226)
TOTAL GENERAL SERVICE RATE GS & SH RIDER				**$ 83,495,405**		**$ 89,975,041**
PROPOSED INCREASE						**$ 6,479,636**
Percentage Increase						7.76%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
LARGE COMMERCIAL RATE LC - PRIMARY VOLTAGE					
Customer Charges	531	$ 17.70	5 9,399	$ 65.00	5 34,515
Demand Charges	*kW-Months*				
Summer Season	127,056	$ 8.44	1,072,353	$ 12.32	1,565,330
Winter Season	214.932	$ 5.64	1,212,216	$ 9.52	2,046,153
	341.968				
	kWh's				
Energy Charges	154,967,220	5 0.02959	4,565,480	$ 0.02349	3,640,180
Subtotal @ base rates before application of correction factor			I 6,879,448		I 7286.178
Correction Factor -		0.999428		0.999426	
Subtotal @ base rates after application of correction factor			I 6,883,383		I 7290,346
Fuel Adjustment Clause - proforma for rollin			(72,627)		(72,627)
Merger Surcredit			(190,189)		(190,189)
Value Delivery Surcredit			(43.162)		(43.162)
VDT Amortization & Surcredit Adjustment			505		505
Adjustment to Reflect Year-End Customers	#REF!				
TOTAL LARGE COMMERCIAL RATE LC PRIMARY			$ 6,577,911		I 6,984,873
PROPOSED INCREASE					$ 406.962
Percentage Increase					6.19%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
LARGE COMMERCIAL RATE LC .SECONDARY VOLTAGE						
Customer Charges	30,959		$ 17.70	$ 547,974	5 65.00	5 2,012,335
Demand Charges		kW-Months				
Summer Season		1,823,049	$ 10.32	18,813,866	$ 14.20	25,887,296
Winter Season		3,242,275	$ 7.26	23,538,917	5 11.14	36.1 18,944
		5,065,324				
		kWh's				
Energy Charges		2,059,176,673	$ 0.02959	60,931,038	5 0.02349	48,370,060
Subtotal @ base rates before application of correction factoi				$ 103,831,794		$ 112,388,634
Correction Factor -			0.999428		0.999428	
Subtotal @ base rates after application of correction factor				$ 103,891,193		$ 112,452,929
Fuel Adjustment Clause. pmforma for rollin				(1,002,645)		(1,002,645)
Merger Surcredit				(2,866,140)		(2,866,140)
Value Delivery Surcredit				(651,470)		(651,470)
VDT Amortization 6 Surcredit Adjustment				7,617		7,617
Adjustment to Reflect Year-End Customers		19,155,120		932.854		1,013,228
TOTAL LARGE COMMERCIAL RATE LC SECONDARY				$ 100,311,410		$ 108,953,519
PROPOSED INCREASE						$ 8,642,109
Percentage Increase						8.62%
Total Large Commercial Rate LC				$ 106,889,321		$ 115,938,392
PROPOSED INCREASE						$ 9,049,072
Percentage Increase						8.47%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roil-In Rater		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rater
LARGE COMMERCIAL RATE LCTOD - PRIMARY VOLTAGE									
Customer Charges	123	$	19.76	$	2,433	$	90.00	$	11,070
	kW-Months								
Basic Demand Charges	520,367	$	1.98		1,030,327	$	2.17		1,129,196
Peak Demand Charges	*kW-Months*								
Summer Peak	194,877	$	6.63		1,292,035	$	10.15		1,978,002
Winter Peak	322.246	$	3.54		1,140,756	$	7.35		2,368,523
	517,125								
	kWh's								
Energy Charges	261,433,800	$	0.02963		7,746,263	$	0.02349		6,141,060
Subtotal @ base rates before application of correction factor				$	11,211,636			$	11,627,871
Correction Factor -			1.002249				1.002249		
Subtotal @ base rates after application of correction factor				I	11,166,675			$	11,601,776
Fuel Adjustment Clause - proforma for rollin					(125,669)				(125.669)
Merger Surcredit					(306,135)				(306.135)
Value Delivery Surcredit					(69,688)				(69,688)
VDT Amortization 8 Surcredit Adjustment					615				815
Adjustment to Reflect Year-End Customers									
TOTAL LARGE COMMERCIAL RATE LCTOD PRIMARY				$	10,663,797			I	11,098,899
PROPOSED INCREASE								$	415,102
Percentage Increase									3.89%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
LARGE COMMERCIAL RATE LCTOD .SECONDARY VOLTAGE					
Customer Charges	604	$ 19.76	$ 11,947	5 90.00	5 54,360
	kW-Months				
Basic Demand Charges	671.385	$ 3.68	2,470,697	$ 3.22	2,161,860
Peak Demand Charges	kW-Months				
Summer Peak	232,987	$ 6.63	1,544,704	$ 10.98	2,558,197
Winter Peak	433,763	$ 3.54	1,535,521	5 7.92	3,435,403
	666,750				
	kWh's				
Energy Charges	308,993,871	$ 0.02963	9,155,488	$ 0.02349	7,258,266
Subtotal @ base rates before application of correction factor			$ 14,718,357		I 15,468,086
Correction Factor -		1.002249		1.002249	
Subtotal @ base rates after application of correction factor			I 14,685,327		$ 15,433,373
Fuel Adjustment Clause. proforma for rollin .			(153,023)		(153,023)
Merger Surcredit			(403,395)		(403,395)
Value Delivery Surcredit			(91.549)		(91,549)
VDT Amortization & Surcredit Adjustment			1.070		1,070
Adjustment to Reflect Year-End Customers	12,359,754		568.077		596,243
TOTAL LARGE COMMERCIAL RATE LCTOD SECONDARY			$ 14,604,508		I 15,382,720
PROPOSED INCREASE					$ 778.212
Percentage Increase					5.33%
TOTAL LARGE COMMERCIAL RATE LCTOO			$ 25,288,305		I 26,481,619
PROPOSEDINCREASE					$ 1,193,314
Percentage Increase					4.72%
TOTAL LARGE COMMERCIAL (LC and LC-TOD)			$ 132,177,625		$ 142,420,011
PROPOSEDINCREASE					$ 10,242,388
Percentage Increase					7.75%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LP - TRANSMISSION VOLTAGE					
Customer Charges		5 43.78	$	$ 90.00	5
Demand Charges	kW-Months				
Summer Season		$ 7.59		$ 11.35	
Winter Season		$ 5.00		$ 8.76	
	kWh's				
Energy Charger		$ 0.02542		$ 0.02000	
Power Factor Provision	kW-Months				
Summer Season		5 7.59		$ 11.35	
Winter Season		$ 5.00		$ 8.76	
Subtotal @ base rates before application of correction factor			$ -		$
Correction Factor.					
Subtotal @ base rates after application of correction factor			$		$
Fuel Adjustment Clause. proforma for rollin					
Merger Surcredit					
Value Delivery Surcredit					
VDT Amortization & Surcredit Adjustment					
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LP PRIMARY					$ -
PROPOSED INCREASE					$ -
Percentage Increase					

Note: Currently no customers are served under this rate

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LP - PRIMARY VOLTAGE					
Customer Charges	494	$ 43.78	$ 21,627	$ 90.00	$ 44,460
Demand Charger	kW-Months				
Summer Season	95,177	$ 8.78	835,654	$ 12.55	1,194,471
winter Season	181,277	$ 6.17	1,118,479	$ 9.96	1,805,519
	276,454				
	kWh's				
Energy Charges	111,622,714	$ 0.02542	2,837,449	$ 0.02000	2,232,454
Power Factor Provision	kW-Months				
Summer Season	(806)	$ 8.78	(7,077)	$ 12.55	(10,115)
Winter Season	(3,501)	$ 6.17	(21,601)	$ 9.96	(34.870)
	(4,307)				
Subtotal @ base rates before application of correction factor			$ 4,784,532		$ 5,231,919
Correction Factor -		0.999681		0.999681	
Subtotal @ base rates after application of correction factor			$ 4,706,080		$ 5,233,590
Fuel Adjustment Clause - proforma for rollin			(58.665)		(58.665)
Merger Surcredit			(130,757)		(130,757)
Value Delivery Surcredit			(29,824)		(29,824)
VDT Amortization & Surcredit Adjustment			349		349
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LP PRIMARY			$ 4,567,163		$ 5,014,693
PROPOSED INCREASE					$ 447,530
Percentage Increase					9.80%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LP -SECONDARY VOLTAGE									
Customer Charges	4,225	$	43.76	$	184,971	5	90.00	$	380.250
Demand Charges	*kW-Months*								
Summer Season	485.652	$	10.69		5,300,656	$	14.35		7.115.476
Winter Season	927,407	$	8.11		7,521,271	$	11.76		10,906,306
	1,423,259								
	kWh's								
Energy Charges	553,636,275	$	0.02542		14,078,518	$	0.02000		11,076,726
Power Factor Provision	*kW-Months*								
Summer Season	(4,581)	$	10.69		(48,971)	$	14.35		(65,737)
Winter Season	(10,121)	$	6.11		(82,061)	$	11.76		(119,023)
	(14,702)								
Subtotal @ base rates before application of correction factor				$	26,954,365			I	29,293,998
Correction Factor -			0.999661				0.999681		
Subtotal @ base rates after application of correction factor				$	26,962,971			$	29,303,351
Fuel Adjustment Clause - proforma for rollin					1277.626)				(277.626)
Merger Surcredit					(738,856)				(736.656)
Value Delivery Surcredit					(167.175)				(167,175)
M T Amortization & Surcredit Adjustment					1,965				1,955
Adjustment to Reflect Year-End Customers	3,146,798				147.900				161,327
TOTAL INDUSTRIAL POWER RATE LP SECONDARY				$	25,929,168			$	28,282,975
PROPOSED INCREASE								I	2,353,807
Percentage increase									9.08%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON ES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT :S REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN API TO TEST PERIOD LING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LPTOD .TRANSMISSION VOLTAGE									
Customer Charges	73	$	45.81	$	3.344	$	120.00	$	8.760
	kW-Months								
Basic Demand Charges	696.768	$	2.10		1,463,255	$	2.33		1,623,516
Peak Demand Charges	*kW-Months*								
Summer Peak	234.813	$	5.50		1,291,472	$	9.02		2,116,013
Winter Peak	454,878	$	2.92		1,328,244	$	6.43		2,924,866
	689,691								
	kWh's								
Energy Charges	376,359,726	$	0.02542		9,567,064	$	0.02000		7,527,195
Power Factor Provision	*kW-Months*								
Basic Demand	(25.159)	$	2.10		(52,834)	$	2.33		(58.620)
Summer Peak	(7,762)	$	5.50		(42,691)	$	9.02		(70.013)
Winter Peak	(1215)	$	2.92		(50.268)	$	6.43		(110,692)
	kW-Months								
Interruptible Service Rider	411,322	$	(3.30)		(1,357,363)	5	(3.10)		(1,275,098)
Subtotal @ base rates before application of correction factor				$	12,150,223			$	. 12,687,925
Correction Factor .			1.000343				1.000343		
Subtotal @ base rates after application of correction factor				I	12,146,053			$	12,083,570
Fuel Adjustment Clause - proforma for rollin					(213,291)				(213,291)
Merger Surcredit					(328.889)				(328.889)
Value Delivery Surcredit					(74,173)				(74.173)
VDT Amortization & Surcredit Adjustment					867				867
Adjustment lo Reflect Year-End Customers									
TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION				$	11,530,567			$	12,068,084
PROPOSED INCREASE								$	537,517
percentage Increase									4.66%
TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION (without Interruptible Credit)				I	12,887,929			$	13,343,182
PROPOSED INCREASE (without **Interruptible Credit)**								$	455.253
percentage increase									3.53%

LG&E Electric Exhibit 1
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LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LPTOD - PRIMARY VOLTAGE									
Customer Charges	540	$	45.61	$	24.737	$	120.00	$	64,800
	kW-Months								
Basic Demand Charges	2,963,564	$	3.29		9,750,126	$	3.52		10,431,745
Peak Demand Charges	*kW-Months*								
Summer Peak	996.472	$	5.50		5,480,596	$	9.03		8,998,142
Winter Peak	1,952,825	$	2.92		5,702,249	$	6.44		12,576,193
	2,949,297								
	kWh's								
Energy Charges	1,597,360,760	$	0.02542		40,604,91 1	$	0.02000		31,947,215
Power Factor Provision	*kW-Months*								
Basic Demand	(103,903)	$	3.29		(341,840)	$	3.52		(365,737)
Summer Peak	(41,348)	$	5.50		(227.4121	$	9.03		(373,369)
Winter Peak	(58,2311	$	2.92		(170,035)	$	6.44		(375.008)
	kW-Months								
Interruptible Service Rider	344.897	$	(3.30)		(1,138,160)	$	(3.20)		(1,103,670)
Subtotal @ bare rates before application of correction factoi				$	59,685,172			I	61,800,311
Correction Factor -			1.000342				1.000342		
Subtotal @ base rates after application of correction factor				$	59,664,762			$	61,779,178
Fuel Adjustment Clause - proforma for rollin					(864,770)				(864,770)
Merger Surcredit					(1,626,347)				(1,626,347)
Value Delivery Surcredit					(366.371)				(366,371)
VOT Amortization 8 Surcredit Adjustment					4.284				4.284
Adjustment to Reflect Year-End Customers									
TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY				I	56.81 1,559			I	58,925,974
PROPOSED INCREASE								$	2,444,446
Percentage Increase									3.72%
TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY (without Interruptible Credit)				$	57,949,719			$	60,029,644
PROPOSED INCREASE (without Interruptible Credit)								$	2,079,926
Percentage Increase									3.59%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LPTOD - SECONDARY VOLTAGE					
Customer Charges	151	$ 45.81	$ 6,917	$ 120.00	$ 18,120
	kW-Months				
Basic Demand Charges	114,966	$ 5.25	603.572	$ 4.62	531.143
Peak Demand Charges	*kW-Months*				
Summer Peak	31.727	$ 5.50	174,499	$ 9.73	308.704
Winter Peak	80,068	$ 2.92	233,799	$ 7.14	571.666
	111.795				
	kWh's				
Energy Charges	42,810,915	$ 0.02542	1,088253	$ 0.02000	856,218
Power Factor Provision	*kW-Months*				
Basic Demand	(1,951)	$ 5.25	(10.243)	$ 4.82	(9,014)
Summer Peak	(533)	$ 5.50	(2,932)	$ 9.73	(5,186)
Winter Peak	(1.404)	$ 2.92	(4.100)	$ 7.14	(10.025)
Subtotal @ base rates before application of correction factor			$ 2,089,765		I 2,281,846
Correction Factor -		1.000343		1.000343	
Subtotal @ base rates after application of correction factor			I 2,089,048		$ 2,260,870
Fuel Adjustment Clause - proforma lor rollin			(21,506)		(21,506)
Merger Surcredit			(56.520)		(56.520)
Value Delivery Surcredit			(12.486)		(12,486)
VOT Amortization & Surcredit Adjustment			146		146
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LPTOD SECONDARY			$ 1,998,882		$ 2,170,504
PROPOSED INCREASE					I 171,822
Percentage Increase					8.80%
TOTAL INDUSTRIAL POWER RATE LESS INTERRUPTIBLE CREDIT			$ 103,332,661		I 108,840,999
PROPOSED INCREASE					$ 5,508,337
Percentage Increase					5.33%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED *TO* TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
SPECIAL CONTRACT									
Demand Charger	*kW-Months*								
Summer Season	154.000	$	6.43		1,298,220	$	11.94		1,838,760
winter Season	216.450	$	6.24		1,350,648	5	9.75		2,110,388
	370.450								
	kWh's								
Energy Charges	195,880,000	$	0.02437		4,773,596	$	0.02000		3,917,600
Power Factor Provision	*kW-Months*								
Summer Season	(11.539)	$	8.43		(97.275)	$	11.94		(137.778)
Winter Season	(16,4501	$	6.24		(102.649)	$	9.75		(160,389)
	(27.969)								
Subtotal @ base rates before application of correction factor				$	7,222,539			$	7,568,580
Correction Factor -			1.000000				1.000000		
Subtotal @ base rates after application of correction factor				$	7,222,538			$	7,568,580
Fuel Adjustment Clause. proforma for rollin					(66.299)				(86.299)
Merger Surcredit					(199.899)				(199,899)
Value Delivery Surcredit					(45,934)				(45.934)
VDT Amortization & Surcredit Adjustment					537				537
TOTAL SPECIAL CONTRACT				I	6,890,944			I	7,236,985
PROPOSED INCREASE								$	346,041
Percentage Increase									5.02%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SAI ES FOR THE 12 MONTHS ENDED ! EPTEMBEF 30,.2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
	kW-Months				
Demand Charges	221.864	$ 11.01	2,442,723	$ 11.15	2,473,784
	kWh's				
Energy Charges	145,699,200	$ 0.01852	2,898,349	16 0.02000	2,913,984
Subtotal @ base rater before application of correction factor			I 5,141,072		$ 5,387,768
Correction Factor-		1.000000		1.000000	
Subtotal @ base rates after application of correction factor			I 5,141,072		$ 5,387,788
Fuel Adjustment Clause. proforma for rollin			(75.153)		(75.153)
Merger Surcredit			(139,387)		(139,387)
Value Delivery Surcredit			(31,349)		(31,349)
VDT Amortization 8 Surcredit Adjustment			367		367
TOTAL SPECIAL CONTRACT			$ 4,895,550		$ 5,142,246
PROPOSED INCREASE					$ 248.896
Percentage Increase					5.04%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
Customer Charger	12	$ 74.29	$ 891	5 120.00	$ 1,440
	kW-Months				
Basic Demand Charges	402,555	$ 5.93	2,387,151	$ 6.30	2,536,097
Peak Demand Charges	kW-Months				
Summer Peak	137,065	$ 8.19	1,122,562	$ 7.65	1,048,547
Winter Peak	238,810	$ 3.81	909.866	$ 3.27	780.909
	375,875				
	kWh's				
Energy Charges	155,404,800	5 0.01751	2,721,138	$ 0.02000	3,108,096
Power Factor Provision	kW-Months				
Basic Demand	(16.663)	$ 5.93	(110.671)	5 6.30	(117,576)
Summer Peak	(6,720)	$ 8.19	(55.036)	5 7.65	(51.407)
Winter Peak	(10,724)	5 3.61	(40.860)	5 3.27	(35,068)
	kW-Months				
interruptible Service Rider		$		$ (3.30)	
Subtotal @ base rates before application of correction factor			$ 6,935,043		$ 7271.037
Correction Factor-		1.000000		1.000000	
Subtotal @ base rates after application of correction factor			$ 6,935,043		$ 7,271,037
Fuel Adjustment Clause. proforma for rollin			(76.751)		(76.751)
Merger Surcredit			(191,055)		(191.055)
Value Delivery Surcredit			(43.460)		(43.460)
VDT Amortization & Surcredit Adjustment			508		508
TOTAL SPECIAL CONTRACT			$ 6,624,286		$ 6,960,280
PROPOSED INCREASE					$ 335.994
Percentage Increase					5.07%

LG&E Electric Exhibit 1
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LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
Customer Charger	12	$ 74.29	$ 891	$ 74.29	$ 891
	kW-Months				
Basic Demand Charges	624,000	$ 4.36	2,720,640	$ 4.62	2,882,880
Peak Demand **Charges**	*kW-Months*				
Summer **Peak**	180,000	$ 8.19	1,474,200	$ 7.65	1,377,000
Winter Peak	360,000	$ 3.81	1,371,600	$ 3.27	1,177,200
	540,000				
	kWh's				
Energy Charges	199,644,549	$ 0.01751	3,495,776	$ 0.02000	3,992,891
P a e r Factor Provision	*kW-Months*				
Basic Demand	(49,504)	$ 4.36	(215,837)	$ 4.62	(228.708)
Summer **Peak**	(14,040)	$ 8.19	(114.988)	$ 7.65	(107.408)
Winter Peak	(28,800)	$ 3.81	(109,7281	5 3.27	(94,176)
	kW-Months				
Interruptible Service Rider	120.000	$ (3.30)	(396,000)	$ (3.10)	(372.000)
Station House Credit			(1,200)		(1,200)
Subtotal @ base rates before application of correction factor			$ 8,225,354		$ 8,627,312
Correction Factor.		1.000078		1.000078	
Subtotal @ base rates after application **of** correction factor			$ 8,224,717		$ 8,626,703
Fuel Adjustment Clause - **proforma** for rollin			(102,665)		(102,665)
Merger Surcredit			(225,529)		(225.529)
Value Delivery Surcredit			(51.289)		(51,289)
VDT **Amortization &** Surcredit **Adjustment**			600		600
TOTAL SPECIAL CONTRACT			$ 7,845,834		$ 8,247,820
PROPOSED INCREASE					$ 401,986
Percentage increase					5.12%
TOTAL SPECIAL CONTRACT (without Interruptible Credit)			8 241 034		$ 8,619,820
PROPOSED INCREASE					$ 377,986
Percentage increase					4.59%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
SPECIAL CONTRACT									
	kW-Months								
Demand Charges	104,943	5	7.53		790.221	$	8.33		874,175
	kWh's								
Energy Charges	56.404.800	5	0.01975		1,115,772	$	0.01088		1,123,117
Subtotal @ base rates before application of correction factor				$	1,905,993			$	1,997,292
Correction Factor -			1.000000				1.000000		
Subtotal @ base rates after application of correction factor				$	1,905,993			$	1,997,292
Fuel Adjustment Clause. proforma for rollin					(28.377)				(28,377)
Merger Surcredit					(51.718)				(51.718)
Value Delivery Surcredit					(11,705)				(11.705)
VDT Amortization 6 Surcredit Adjustment					137				137
TOTAL SPECIAL CONTRACT				$	1,814,330			$	1,905,829
PROPOSED INCREASE								$	91,299
Percentage Increase									5.03%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
STREET LIGHTING ENERGY RATE SLE						
		kWh's				
Energy Charges		3,992,315	$ 0.03788	151,229	$ 0.04059	162,048
Subtotal @ base rates before application of correction factor				$ **151,229**		$ **162,048**
Correction Factor -			1.001986		1.001986	
Subtotal @ base rates after application of correction factor				$ **150,929**		$ **161,727**
Fuel Adjustment Clause - proforma for rollin				(2,325)		(2,325)
Merger Surcredit				(4,081)		(4,081)
Value Delivery Surcredit				(887)		(887)
VDT Amortization & Surcredit Adjustment				10		10
Adjustment to Reflect Year-End Customers		(31,939)		(1,159)		(1,247)
TOTAL STREET LIGHTING ENERGY RATE SLE				$ 142,487		$ 153,197
PROPOSED INCREASE						$ 10,711
Percentage Increase						7.52%
TRAFFIC LIGHTING ENERGY RATE TLE						
Customer Charges	10,370		$2.54	$ 26,340	$ 2.80	$ 29,036
		kWh's				
Energy Charges		11,472,338	$ 0.04777	548,034	$ 0.05114	586,695
Subtotal @ base rates before application of correction factor				$ **574,373**		$ **615,731**
Correction Factor -			0.993299		0.993299	
Subtotal @ base rates after application of correction factor				$ **578,248**		$ **619,885**
Fuel Adjustment Clause - proforma for rollin				(6,274)		(6,274)
Merger Surcredit				(15,832)		(15,832)
Value Delivery Surcredit				(3,492)		(3,492)
VDT Amortization & Surcredit Adjustment				41		41
Adjustment to Reflect Year-End Customers		119,502		5,808		6,245
TOTAL TRAFFIC LIGHTING ENERGY RATE TLE				$ 558,499		$ 600,573
PROPOSED INCREASE						$ 42,075
Percentage Increase						7.53%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
PUBLIC STREET LIGHTING RATE PSL					
	Lights				
OVERHEAD SERVICE					
Mercury Vapor - Installed prior to January 1, 1991					
100 Wall	564	$6.08	$ 3,429	$ 6.52	$ 3.677
175 Wall	35.831	$7.08	253,083	$ 7.59	271.957
250 Wall	58.512	$8.03	469,851	$ 8.81	503.788
400 **Wall**	85.032	$9.56	812.906	$ 10.25	871.578
400 Walt (metal pole)		$13.90		$ 14.90	
1000 Wan	168	$17.64	2.964	$ 18.92	3.179
Mercury Vapor - Installed after December 31. 1990					
100 wan					
175 Wall	24	$ 8.81	211	$ 9.45	227
250 Wall	631	$ 9.86	6.222	$ 10.57	8,670
400 Wall	204	$ 11.60	2,407	$ 12.85	2.581
400 Wall (metal pole)					
1000 Wan	96	$ 21.24	2.039	$ 22.78	2.187
Sodium Vapor - Installed prior to January 1.1991					
100 wan	216	$7.27	1,570	$ 7.80	1.885
150 Watt	23,400	$8.89	203,346	$ 9.32	218,088
250 **Walt**	26.448	$10.37	274,268	$ 11.12	294.102
400 Wall	54,105	$10.72	580,008	$ 11.49	621.666
1000wan					
Sodium Vapor - Installed after December 31,1990					
100 **Watt**	4,290	$ 7.27	31,188	$ 7.80	33,462
150 Wall	6.347	$ 6.69	55.155	$ 9.32	59,154
250 Wall	840	$ 10.37	8,711	$ 11.12	9,341
400 wan	22.793	$ 10.72	244.341	$ 11.49	261,892
1000 **Watt**	24	$ 24.37	585	$ 28.13	627

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rater	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
PUBLIC STREET LIGHTING RATE PSL (continued)					
	Lights				
UNDERGROUND SERVICE					
Mercury Vapor- Installed prior to January 1, 1991					
100 Watt **Top** Mounted	1,200	$ 9.98	11.952	$ 10.68	12,816
175 Watt **Top** Mounted	12.888	$ 10.86	139.984	$ 11.65	150.145
175 Watt	1,236	$ 14.77	18.256	$ 15.84	19,578
250 Wan	12,120	$ 15.78	191,011	$ 16.90	204.828
400 Wan	8.364	$ 18.49	154,650	$ 19.83	165.858
400 Wan **(metal pole)**	4.452	5 18.49	82.317	$ 19.83	88.283
Mercury Vapor - Installed after December 31. 1990					
100 Wan **Top** Mounted		$ 12.30		5 13.19	
175 Watt **Top** Mounted	444	$ 13.32	5.914	$ 14.28	6,340
175 Watt		5 21.04		$ 22.56	
250 **Watt**	300	$ 22.08	8.624	$ 23.68	7.104
400 Wall		$ 24.02		$ 25.76	
400 Watt **(metal pole)**		$ 24.02		$ 25.76	
Sodium Vapor - **Installed** prior to January 1, 1991					
70 Walt **Top** Mounted				$	
100 Watt **Top Mounted**	23.244	5 10.94	254.289	$ 11.73	272.652
150 **Watt Top** Mounted				$	
150 wan	2,340	5 18.96	44,366	$ 20.33	47.572
250 Wall	6,744	$ 20.06	135,285	$ 21.51	145,063
250 Wall (metal **pale)**	1.344	$ 20.06	26,981	5 21.51	28,909
400 Watt	7.404	$ 21.42	158.594	$ 22.97	170,070
400 Wan (metal **pole)**	2.160	5 21.42	46.267	$ 22.97	49.615
1000 Watt					
Sodium Vapor. installed **after December** 31, 1990					
70 Watt **Top** Mounted	2,316	$ 10.55	24.434	$ 11.31	26,194
100 Watt **Top** Mounted	58.564	$ 10.94	640,690	$ 11.73	688,956
150 Watt **Top** Mounted	4.124	$ 16.18	66.726	$ 17.35	71,551
150 watt	1.125	$ 18.96	21,330	$ 20.33	22,871
250 Watt	444	$ 20.06	8,907	$ 21.51	9,550
250 Watt (metal **pale)**		5 20.06		$ 21.51	
400 Watt	2,936	$ 21.42	62,889	$ 22.97	67.440
400 Wan (**metal** pole)	12	$ 21.42	257	5 22.97	276
1000 Watt	24	$ 49.85	1,196	$ 53.45	1,283

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Rail-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
PUBLIC STREET UGHTING RATE PSL (continued)					
DECORATIVE UGHTING FIXTURES					
installed after December 31, 1990	*Lights*				
Acorn w/decorative baskets					
70 Watt Sodium Vapor	132	$ 14.57	1.923	5 15.62	2,062
100 Watt Sodium Vapor	1,044	$ 15.15	15.817	$ 16.25	16,965
8-Sided Coach					
70 Watt Sodium Vapor	432	I 14.76	6,316	$ 15.83	6.839
100 Watt Sodium Vapor		5 15.33		I 16.44	
Poles	*Poles*				
10ft Smooth	569	5 8.73	4.970	$ 9.36	5,328
10ft Fluted	702	$ 10.42	7.312	$ 11.17	7.838
Bases	*Bases*				
Old Town/Manchester	115	$ 2.80	322	$ 3.00	345
Cheaspeak/Franklin	233	5 3.00	700	$ 3.22	751
Jefferson/Winchester	710	5 3.03	2.151	5 3.25	2.307
Norfolk/Essex	142	$ 3.19	453	I 3.42	486
Subtotal @ base rates before application of Correction factor			$ 5,095,104		$ 5,463,137
Correction Factor -		0.997825		0.997825	
Subtotal @ base rates after application of correction factor			$ 5,106,893		$ 5,415,640
Fuel Adjustment Clause - proforma for rollin			(28.056)		(28.056)
Merger Surcredit			(140.918)		(140.918)
Value Delivery Surcredit			(31.091)		(31,091)
VDT Amortization & Surcredit Adjustment			364		364
Adjustment to Reflect Year-End Customers	24		2,999		3,225
TOTAL PUBLIC STREET LIGHTING RATE PSL			$ 4,910,190		$ 5,279,170
PROPOSED INCREASE					$ 368,901
Percentage increase					7.51%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC PATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
OUTDOOR LIGHTING SERVICE RATE OL					
	Lights				
OVERHEAD SERVICE					
Mercury Vapor - Installed prior to January 1, 1991					
100 Wall	728	$ 6.78	$ 4,936	$ 7.27	$ 5.293
175 Wan	39.923	$ 7.63	304,612	$ 8.18	326,570
250 Wall	19.562	$ 8.63	168,820	$ 9.25	180,949
400 Wall	21.141	$ 10.44	220.712	$ 11.19	236,568
1000 Watt	4,443	$ 18.93	84.106	$ 20.30	90,193
Sodium Vapor. Installed prior To January 1, 1991					
100 wan	2,836	$ 7.53	21,355	$ 8.07	22.887
150 wan	7,820	$ 9.82	75,228	$ 10.32	80,702
250 Watt	4.927	$ 11.32	55,774	$ 12.14	59,814
400 Wan	50.448	$ 11.89	599,627	$ 12.75	643.212
1000 Watt					
	Poles				
Pole Charges	56.430	$ 1.66	93.674	$ 1.78	100,445
	Lights				
UNDERGROUND SERVICE					
Mercury Vapor. Installed prior lo January 1, 1991					
100 Wall Top Mounted	516	$ 11.84	6,109	$ 12.70	6,553
175 Watt Top Mounted	6,781	$ 12.57	85,237	$ 13.48	91,408
Sodium Vapor. Installed prior to January 1, 1991					
70 Wall Top Mounted		$ 10.55		$ 11.31	
100 Watt Top Mounted	15.235	$ 13.93	212.224	$ 14.94	227,611
150 Watt Top Mounted					
150 Wan		$ 18.98		$ 20.35	
250 Watt	384	$ 21.72	8,340	$ 23.29	8.943
400 Watt	509	$ 23.85	12,140	$ 25.57	13.015
1000 Wall					

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
OUTDOOR LIGHTING SERVICE RATE OL (continued)							
OVERHEAD SERVICE							
Mercury Vapor- Installed after December 31. 1990							
100 watt							
175 Watt	1.127	5	8.99	10,132	$	9.64	10.664
250 Watt	733	$	10.04	7,359	5	10.77	7,894
400 Walt	2,232	$	11.98	28,739	5	12.85	28,681
1000 watt	4,756	$	21.50	102,254	$	23.05	109,626
Sodium Vapor - Installed **after December** 31. 1990							
100 watt	23,025	5	7.53	173.378	5	8.07	185,612
150 wan	19,460	$	9.62	187.205	5	10.32	200.827
250 Watt	4,986	$	11.32	55.442	$	12.14	60,530
400 Wall	107.923	$	11.89	1,283,204	$	12.75	1,376,018
1000 watt	154	5	28.16	4,337	$	30.20	4,651
	Poles						
Pole Charges	46.247	$	1.66	76,770	$	1.78	62,320
UNDERGROUND SERVICE							
Mercury Vapor. Installed after December 31.1990							
100 Wan Top **Mounted**		$	12.57		$	13.48	
175 Wall **Top Mounted**	2.600	$	13.51	35.126	5	14.49	37,874
Sodium Vapor. Installed after December 31. 1990							
70 Watt Top **Mounted**	14,991	5	10.55	158.155	$	11.31	189.546
100 Watt **Top Mounted**	95.063	$	13.93	1,324,228	$	14.94	1,420,241
150 Walt **Top Mounted**	9.267	$	18.89	156,520	$	18.11	167,825
150 Watt	5.145	$	18.98	97.652	$	20.35	104,701
250 wan	5.605	$	21.72	121,741	5	23.29	130,540
400 Watt	16,237	$	23.85	387.252	$	25.57	415.180
1000 watt	286	5	53.63	15.338	$	57.51	16,448

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT **RATES** REVISED TO INCLUDE JANUARY **2004** ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rater
OUTDOOR LIGHTING SERVICE RATE OL (continued)									
DECORATIVE LIGHTING FIXTURES									
Installed after December 31.1990	*Lights*								
Acorn w/decorative baskets									
70 Walt Sodium Vapor	243	$	14.95		3.633	I	16.03		3,895
100 Watt Sodium Vapor	1.668	$	15.64		26.088	$	16.77		27,972
8-Sided Coach									
70 Watt Sodium Vapor	869	$	15.12		13.442	I	16.21		14.411
100 Watt Sodium Vapor	336	$	15.61		5.312	$	16.95		5,695
Poles	*Poles*								
10ft Smooth	1.392	$	6.73		12.152	$	9.36		13,029
10ft Fluted	1.716	I	10.42		17.880	$	11.17		19,167
Bases	*Bases*								
Old Town/Manchester	297	I	2.80		832	S	3.00		892
Cheaspeak/Franklin	603	$	3.00		1,809	$	3.22		1,942
Jefferson/Winchester	1,836	I	3.03		5,562	$	3.25		5,968
Norfolk/Essex	367	I	3.19		1,171	$	3.42		1,256
Subtotal @ bass rates before application of correction factor				$	6,264,808			$	6,717,769
Correction Factor.			0.996100				0.996100		
Subtotal @ bass rates after application of correction factor				$	8,289,337			$	6,744,072
Fuel Adjustment Clause - proforma for rollin					(29,131)				(29,131)
Merger Surcredit					(172,037)				(172,037)
Value Delivery Surcredit					(38,768)				(38,766)
VDT Amortization & Surcredit Adjustment					453				453
Adjustment to Reflect Year-End Customers	115				17.114				18,401
TOTAL OUTDOOR LIGHTING RATE OL				$	6,066,969			$	6,522,990
PROPOSED INCREASE								$	456,021
Percentage Increase									7.52%

Louisville Gas and Electric Company
Summary of Settlement Gas Rate increase by Rate Class
Based on Adjusted Sales and Transportation
For the 12 months Ended September 30, 2003

	Adjusted Billings at Current Rates	Proposed increase In Revenue As Filed	Percentage Increase	increase Per Proposed Settlement	Percentage increase	Percentage of Total
Residential Gas Service Rate RGS	$ 226,193,722	$ 17,187,887	7.60%	$ 9,782,051	4.32%	83.01%
Firm Commercial Gas Service Rate CGS	103,596,812	1,593,870	1.54%	1,774,266	1.71%	15.06%
Firm Industrial Gas Service Rate IGS	11,973,655	198.751	1.66%	218,727	1.83%	1.86%
As Available Gas Service Rate AAGS	3,005,383	6	0.00%	8.553	0.28%	0.07%
Firm Transportation Service Rate FT	3,939,208		0.00%		0.00%	0.00%
Pooling Service Rate PS-FT	60,600		0.00%		0.00%	0.00%
Special Contracts	1,681,970		0.00%		0.00%	0.00%
Off-System Sales	-	-		-		
Total Sales and Transportation	350,451,351	18,980,514	5.42%	11,783,597	3.36%	100.00%
Forfeited Discounts	1,264,157					
Reconnection Charges	49,349	12,006		4,002		
Meter Test Charge		31,464		31,464		
Thlrd Trlp inspection Charges	3,105	80.730		80.730		
Other Miscellaneous Revenues	591,441					
Total Revenue	$ 352,359,402	$ 19,104,714	5.42%	$ 11,899,793	3.38%	

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF SETTLEMENT GAS RATE INCREASE BY RATE *CLASS*
BASED ON ADJUSTED SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

REVENUE	(1) Booked Revenue Adjusted to As Billed Basis	(2) Elimination of Gas Supply Cost Recovery (GSC) Revenues (See Exhibit 7)	(3) Elimination of Demand-Side Management (DSM) Revenues	(4) Temperature Normalization Adjustment (See Exhibit 8)	(5) Year-End Customers Adjustment (See Exhibit 9)	(6) Adjustment to Reflect Rate Switching and Plant Closings (See Exhibit 10)	(7) VDT Amortization & Surcredit Adjustment	(8) GSC @ Current Nov03-Jan04 Charges	(9) Adjusted Billings at Current Rates	(10) Proposed Increase in Revenue	(11) Percentage Increase
Residential Gas Service Rate RGS	$ 189,080,204	$ (133,698,514)	$ (1,034,237)	$ 19,079	$ 114,237		$ 149,202	$ 171,563,752	$ 226,193,722	$ 9,782,051	4.32%
Firm Commercial Gas Service Rate CGS	86,731,073	(65,436,260)	(455,264)	66,427	(113,425)	8,682	68,362	82,727,197	103,596,812	1,774,266	1.71%
Firm Industrial Gas Service Rate IGS	9,878,763	(7,988,579)	-	(36,404)	18,710		7,518	10,093,647	11,973,655	218,727	1.83%
As Available Gas Service Rate AAGS	3,079,249	(2,757,374)	(4,883)	(3,938)	(988)	(63,851)	2,451	2,754,718	3,005,383	8,553	0.28%
Firm Transportation Service Rate FT	5,308,129	(1,499,335)	(21,375)	(30,424)	(75,115)	13,838	2,953	242,537	3,939,208	-	0.00%
Pooling Service Rate PS-FT	60,600								60,600	-	0.00%
Special Contracts	1,708,443			(27,762)	-		1,290		1,681,970	-	0.00%
Off-System Sales	10,242,833	(10,242,833)									
Total Sales and Transportation	$ 306,087,293	$ (221,622,896)	$ (1,515,759)	$ (13,022)	$ (56,581)	$ (41,331)	$ 231,796	$ 267,381,851	$ 350,451,351	$ 11,783,597	3.36%
Forfeited Discounts	1,264,157								1,264,157		
Reconnection Charges	49,349								49,349	4,002	
Meter Test Charge	-								-	31,464	
Third Trip Inspection Charges	3,105								3,105	80,730	
Other Miscellaneous Revenues	591,441								591,441		
Total Revenue	$ 307,995,344								$ 352,359,402	$ 11,899,793	3.38%

LG&E Gas Exhibit 1
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LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Residential Gas **Service** Rate RGS	*Customer Months*	*Per customer*		*Per Customer*	
Customer Charges:	3,332,464	$7.00	23,327,246	$8.50	28,325,944
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component:	24,301,485.5	$1,3457	32,702,509	$1.5470	37,594,390
			56,029,757		65,920,342
Residential Gas Service Rate RGS **Summer A/C Rider**					
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Coot Component:	94.0	$0.8457	79	$1.5470	145
Subtotal	24,301,579.5		$ 56,029,837		$ 65,920,487
Correction Factor		0.99938		0.99936	
Subtotal **Rate** RGS after Application of Correction Factor	24,301,579.5		$ 56,065,875		$ 65,962,888
Value Delivery Surcredit			(795,671)		(795,671)
VDT Amortization 8 Surcredit Adjustment			149,202		149,202
Temperature Normalization Adjustment	(671,526.1)	$1.3457	(903,673)	$1.5470	(1,038,851)
Adjustment to Reflect Year-End Customers	48,936.3		114,237		134,453
GSC at Current (Nov03-Jan04) Charges. GSCC	23,678,989.7	$ 7,2454	171,563,752	$ 7.2454	$ 171,563,752
Total Residential Gas Service Rate RGS	23,678,989.7		$ 226,193,723		$ 235,975,773
Proposed **Increase** in Revenue					$9,782,051
					4.32%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

	Billing Determinants		Present Rates	Calculated Revenue at Present Rates		Settlement Rates	Calculated RY at Proposed Rates
Firm Commercial Gas Service Rate CGS	*Customer Months*		Per *Customer*			Per *Customer*	
Customer Charges (Meters < 5000 cf/hr)	281,590		$16.50	4,646,235		$16.50	4,646,235
Customer Charges (Meters >= 5000 cf/hr)	11,489		$117.00	1,344,213		$117.00	1,344,213
	293,079						
	MCF		*Per Mcf*			*Per Mcf*	
Distribution Cost Component:							
On Peak Mcf	10,842,797.2		$1.3457	14,591,152		$1.4968	16,229,499
Off Peak Mcf	877,844.1		$0.8457	742,393		$0 9968	876,035
	11,720,641.3			21,323,993			23,094,962
Gas Transportation Service/Standby Rider to Rate CGS	Customer *Months*		Per customer			Per *Customer*	
Administrative Charges:	24		$90.00	2,160		$90.00	2,160
	MCF		Pet Mcf			Per Mcf	
Distribution Cost Component:							
On Peak M d	88,084.0		$1.3457	118.535		$1,4968	131,644
Off Peak Mcf	17,767.4		$0.8457	15,026		$0.9968	17,711
	105,851.I			135,721			151,715
Firm Commercial Gas Service Rate CGS Summer A/C Rider	*MCF*		*Per Mcf*			*Per Mcf*	
Distribution Cast Component:	40,2540		$0.8457	34,043		$1.4966	60.252
Subtotal	11,866,746.7		1	21,493,156	$		23,306,949
Correction Factor			0.99129			0.99129	
Subtotal Rate CGS after Application of Correction Factor	11,866,746.7			$21,682,647			123.511,114
Value Delivery Surcredit				(364,672)			(364.672)
VDT Amortization & Surcredit Adjustment				68.382			88.382
Temperature Normalization Adjustment	(306,160.2)		$1,3457	(412.0001		$1.4966	(456,261)
Adjustment to Reflect Year-End Customers	(81,647.3)			(113,4251			(122,932)
Adjustment for Rate Switching & Plant Closings: Customer Chgs.	12		$117.00	1,404		$117.00	1.404
Distribution Chgs. -On-Peak	4,407.5		$1.3457	5,931		$1.4968	8,597
Distribution Chgs. - Off-Peak	1,592.0		$0.6457	1,346		$0.9968	1,567
GSC at Current (Nov03-Jan04) Charges - GSCC	11,402,368.1	$	7.2454	82,614,718			82,614,718
GSC at Current Charges - Pipeline Supplier Demand Component	102,570.6	1	1.0966	112,479			112,479
Total Commercial Gar Service Rate CGS	11,504,938.7			$103,596,811			$105,311,071
Proposed Increase in Revenue							$1,774,266
							1.71%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Firm Industrial Gas Service Rate IGS	*Customer Months*	*Per Customer*		*Per Customer*	
Customer Charges (Meters < 5000 cf/hr)	1,463	$16.50	24,140	$16.50	24,140
Customer Charges (Meters >= 5000 cf/hr)	1,245	$1 17.00	145,665	$117.00	145.665
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component:					
On Peak Mcf	1,002,298.3	$1.3457	1,346,793	$1.4966	1,500,240
Off Peak M d	401,064.1	$0.6457	339,160	$0.9966	399,761
	1,403,362.4		1,657,777		2,069,825
GasTransportation Service/Standby Rider lo Rate IGS	*Customer Months*	*Per Customer*		*Per Customer*	
Administrative Charges:	25	$90.00	2,250	$90.00	2.250
	MCF	*Per Mcf*		*Per Mcf*	
Distribution *Cod* Componenl:					
On Peak Mcf	7,600.3	$1,3457	10,226	$1.4966	11.376
Off Peak Mcf	11,340.7	$0.8457	9,591	$0.9966	11,304
	16,9410		22.069		24.931
Subtotal	1,422,303.4		$ 1,879,846		$ 2,094,756
Correction Factor		0.97367		0.97367	
Subtotal Rate IGS after Application of Correction Factor	1,422,303.4		$ 1,930,275		$ 2,150,950
Value Delivery Surcredit			(40,091)		(40,091)
VDT Amortization & Surcredit Adjustment ,			7,516		7.516
Rate Switching / Plant ClosingsAdjustment					
Customer Chgs		$117.00		$117.00	
On Peak *Md*		$1.3457		$1.4968	
Off Peak M d		$0.8457		$0.9968	
Temperature Normalization Adjustment	(27,0520)	$1.3457	(36,404)	$1.4966	(40,491)
Adjustment lo **Reflect Year-End** Customers	13.764		16.710		20,650
GSC at Current (Nov03-Jan04) Charges - GSCC	1,390,271.1	$ 7 2454	10,073,070		10,073,070
GSC at Current Charges - Pipeline Supplier Demand Component	18,764.3	$ 1.0966	20,577		20.577
Total Industrial Gas Service Rate IGS	1,409,035.4		$ 11,973,655		$ 12,192,382
Proposed Increase In Revenue ,					$218.727
					1.83%

LG&E Gas Exhibit 1
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LOUISVILLE GAS AND ƐƖƐƐƖ8ƖƐ COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30, Z003

			Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
As Available Gas Service Rate AAGS							
Customers Currently Taking							
Service Under Rate G-6 and G-6/TS			*Customer Months*	*Per Customer*		*Per Customer*	
Customer Charges:	*G-6*		181	$150.00	27,150	$150.00	27,150
Administrative Charges:	*G-6/TS*		36	$90.00	3,240	$90.00	3,240
			217		30,390		30,390
			MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component:							
	G-6		212,614.6	$0.6855	145,747	$0.5252	111,665
	G-6/TS		58,991.2	$0.6855	40,438	$0.5252	30,982
Subtotal			271,605.8		216,576		173,037
Customers Currently Taking							
Service Under Rate G-7		*Minimum Bills*	*Customer Months*	*Per Minimum*		*Per Customer*	
Minimum Bills		13	144	$500.00	6,500	$150.00	21,600
			MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component			249,255.8	$0.4300	107,180	$0.5252	130,909
Subtotal			249,255.8		113,680		152,509
Subtotal Rate AAGS			520,861 6		**$ 330,256**		**$ 325,547**
Correction Factor				1.000583		1.000583	
Total Rate AAGS after Application of Correction Factor			520,861.6		**$ 330,063**		**$ 325,357**
Value Delivery Surcredit - G6					(6,580)		(6,580)
VDT Amortization & Surcredit Adjustment - G6					1,234		1,234
Value Delivery Surcredit - G7					(6,492)		(6,492)
VDT Amortization & Surcredit Adjustment - G7					1,217		1,217
Temperature Normalization Adjustment - G6			(2,467.9)	$0.6855	(1,692)	$0.5252	(1,296)
Temperature Normalization Adjustment - G7			(5,226.3)	$0.4300	(2,247)	$0.5252	(2,745)
Adjustment to Reflect Year-End Customers - G6			(1,240.3)		(988)		(790)
Adjustment to Reflect Year-End Customers - G7			-				
Adjustment for G6 Rate Switching & Plant Closings:	Customer Chgs.		(36)	0TS0.00	(5,400)	$150.00	(5,400)
	Administrative Chgs.		(24)	$90.00	(2,160)	69000	(2,160)
	Distribution Chgs.		(82,116.8)	$0.6855	(56,291)	$0.5252	(43,128)
GSC at Current (Nov03-Jan04) Charges - GSCC			371,355.1	$ 7.2454	Z.690.6T6		Z.6906T6
GSC at Current Charges - Pipeline Supplier Demand Component			58,455.2	$ 1.0966	64,102		64,102
Total As Available Gas Service Rate AAGS			429,810.2		**$ 3,005,383**		**$ 3,013,936**
Proposed Increase in Revenue							**$8,553**
							0.28%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Firm Transportation Service (Non-Standby) Rate FT					
	Customer Months	*Per Customer*		*Per Customer*	
Administrative Charges:	894	$90.00	80,460	$90.00	80,460
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component	8,392,666.4	$0.4300	3,608,847	$0.4300	3,608,847
Utilization Charge for Daily Imbalances (UCDI):					
Daily Storage Charge:	*930,330.8*	$0.1200	111,640		111,640
Subtotal Rate FT	8,392,666.4		$ **3,800,946**		$ **3,800,946**
Correction Factor		0.99994			
Total Rate FT after Application of Correction Factor	8,392,666.4		$ **3,801,164**	*	**3,801,164**
Value Delivery Surcredit			(15,746)		(15,746)
VDT Amortization & Surcredit Adjustment			2,953		2,953
Adjustment for G6 Rate Switching & Plant Closings: Administrative Chgs.	12	$90.00	1,080		1,080
Distribution Chgs.	29,670.5	$0.4300	12,758		12,758
Temperature Normalization Adjustment	(70,753.1)	$0.4300	(30,424)		(30,424)
Adjustment to Reflect Year-End Customers	(167,555.0)		(75,115)		(75,115)
UCDI Charge - Daily Demand Charge (current Nov03-Jan04)	930,330.8	$ 0.2607	242,537		242,537
Total Firm Transportation (Non-Standby) Rate FT	8,154,358.3		$ **3,939,208**		$ **3,939,208**
Proposed Increase in Revenue					$ **-**
					0.00%
Pooling Service Rate PS-FT	*Customer Months*	*Per Customer*			
Pooling Charges:	808	$75.00	$60,600		$60,600
Correction Factor		1.00000			
Total Pooling Service Rate PS-FT			**$60,600**		**$60,600**
Proposed Increase in Revenue					**$0**
					0.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
.I ION OI SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

		Billing Determinants	Present Rates		Calculated Revenue at Present Rates	Settlement Rates		Calculated Revenue at Proposed Rates
Special Contract		*Customer Months*	*Per Customer*			*Per Customer*		
	Customer Charges:	12	$180.00		2,160	$180.00		2,160
	Administrative Charges:	12	$90.00		1,080	$90.00		1,080
		MCF	*Per Mcf*			*Per Mcf*		
	Distribution Cost Component	1,107,542.5	$0.1049		116,181	$0.1049		116,181
	Demand Charges	112,956.9	$2.7500		310,631	$2.7500		310,631
Subtotal				$	430,053		$	430,053
	Correction Factor		0.99994			0.99994		
Subtotal After Application of Correction Factor					430,078			430,078
VDT Amortization & Surcredit Adjustment					329			329
Value Delivery Surcredit					(1,754)			(1,754)
Temperature Normalization Adjustment		(36,490.3)	$0.1049		(3,828)	$0.1049		(3,828)
Total Special Contract		1,071,052.2		$	424,825		$	424,825
	Proposed Increase in Revenue						$	-
								0.00%

		Billing Determinants	Present Rates		Calculated Revenue at Present Rates	Settlement Rates		Calculated Revenue at Proposed Rates
Special Contract		*Customer Months*	*Per Customer*			*Per Customer*		
	Customer Charges:	12	$180.00		2,160	$180.00		2,160
	Administrative Charges:	12	$90.00		1,080	$90.00		1,080
		MCF	*Per Mcf*			*Per Mcf*		
	Distribution Cost Component	1,324,790.6	$0.1049		138,971	$0.1049		138,971
	Demand Charges	71,028.5	$2.7500		195,328	$2.7500		195,328
Subtotal				$	337,539		$	337,539
	Correction Factor		1.00000			1.00000		
Subtotal After Application of Correction Factor				$	337,539		$	337,539
VDT Amortization & Surcredit Adjustment					263			263
Value Delivery Surcredit					(1,402)			(1,402)
Temperature Adjustment		(10,561.7)	$0.1049		(1,108)	$0.1049		(1,108)
Total Special Contract		1,314,228.9		$	335,292		$	335,292
	Proposed Increase in Revenue						$	-
								0.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Special Contract	*Customer Months*	*Per Customer*		*Per Customer*	
Customer Charges:	24	$180.00	4.320	$180.00	4.320
Administrative Charges:	24	$90.00	2.160	$90.00	2,160
	MCF	Per *M d*		*Per Mcf*	
Distribution Cost Component	2,941,326.6	$0 3200	941.225	$0.3200	041.225
Subtotal		I	947.705	$	947.705
Correction Factor		*1.00000*		1.00000	
Subtotal After Application of Correction Factor		$	947.704	I	947,704
VDT Amortization & Surcredit Adjustment			698		698
Value Delivery Surcredit			(3,723)		(3,723)
Temperature Adjustment	(71,333.1)	$0.3200	(22,827)	$0.3200	(22,627)
Total Special Contract	2,869,993.5	$	921,853	$	921.853
Proposed Increase in Revenue				I	
					0.00%

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Reserved Balancing Service Rate RBS					
	MCF	*Per Mcf*		*Per Mcf*	
Monthly Balancing Charge:		$ 3.65	S0	I 3.85	$0
Monthly Demand Charge:		I 7.93	$0	I 7.93	$0
			$0		$0
Correction Factor				0	
Total after Application of Correction Factor			$0		$0
Proposed Increase in Revenue					$0
					0.00%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAY 0 4 2004

PUBLIC SERVICE

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

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO: 2003-00434

STIPULATION

WHEREAS, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") filed applications to make general adjustments to the Companies' rates, terms and conditions on December 29, 2003 in Case Nos. 2003-00433 and 2003-00434;

WHEREAS, The Kroger Co. was granted full intervention by the Kentucky Public Service Commission ("Commission") on January 22, 2004;

WHEREAS, the Companies and The Kroger Co. (the "parties") wish to facilitate the disposition of these two proceedings through the submission of a joint stipulation on revenue requirement and rate design issues; and,

NOW THEREFORE, pursuant to 807 KAR 5:001 Section 4(6) the parties stipulate as follows:

The Companies will request authority from the Commission to offer experimental time-ofday rate schedules for commercial customers whose maximum monthly demands were greater than 250 KW and less than 2,000 KW during the calendar year 2003 on a revenue-neutral basis. The experimental time-ofday rate schedules will be available to 100 accounts currently served under Rate LC by LG&E, and to 100 accounts currently served under Rate LP by KU.

2 After three years, the Companies will evaluate the performance of the experimental time-of-day rate schedules for the following purposes: (i) to determine the amount of load shifted from the on-peak period to the off-peak period, (ii) to determine the amount of revenue loss from the experimental time-of-day rate schedules, (iii) to evaluate customer acceptance of the experimental time-ofday rate schedules, and (iv) to evaluate the potential for implementing the experimental time-of-day rate schedules as either a permanent demand-side management program or as a standard rate schedule. The Companies shall file a report with the Commission describing their findings within six months after the first three years of implementation of the experimental time-of-day rate schedules. The experimental time-ofday rate schedules shall remain in effect until the rate schedules are terminated by order of the commission.

3. Any customer-specific costs of offering the experimental time-ofday rate schedules, including but not limited to the additional cost of the metering equipment, meter reading, and customer-specific billing costs, shall be recovered through a monthly facilities charge billed to the participants of the experimental time-of-day rate schedules. The monthly facilities charge shall be $15.00 per customer per month.

4. The experimental time-ofday rate schedule for customers served under LG&E's Rate LC shall include energy charges corresponding to $0.0300 per kWh during the designated

on-peak period and $0.0140 per kWh during the designated off-peak period. These charges are based on an energy charge filed by LG&E of $0.0240/kWh. Should the Commission approve an energy charge in this proceeding for Rate LC that differs from the one filed by LG&E, the on-peak and off-peak energy charges shall be adjusted pro-rata to reflect the energy charge established by the Commission. During the summer billing months of June through September, the designated on-peak period shall be: weekdays, from 10 AM. to 9 P.M. Eastern Standard Time (EST) during the four monthly billing periods of June through September. During the winter billing months of October through May, the designated on-peak period shall be: weekdays, from 8 A.M. to 10 P.M Eastern Standard Time (EST) during the eight monthly billing periods of October through May. The designated off-peak period shall be all hours not included during the summer and winter peak periods. The demand and customer charges shall be the Same as approved by the Commission for Rate. LC.

5. The experimental time-of-day rate schedule for customers served under KU's Schedule LP shall include energy charges corresponding to $0.0280 per kWh during the designated on-peak period and $0.0150 per kWh during the designated off-peak period. These charges are based on an energy charge filed by KU of $0.0220/kWh. Should the Commission approve an energy charge for Schedule LP in this proceeding that differs from the one filed by KU, the on-peak and off-peak energy charges shall be adjusted pro-rata to reflect the energy charge established by the Commission. During the summer billing months of June through September, the designated on-peak period shall be: weekdays, from 10 A.M. to 9 P.M. Eastern Standard Time (EST) during the four monthly billing periods of June through September. During the winter billing months of October through May, the designated on-peak period shall be: weekdays, from 8 A.M. to 10 P M Eastern Standard Time (EST) during the eight monthly

billing periods of October through May. The designated off-peak period shall be all hours not included during the summer and winter peak periods. The demand and customer charges shall be the same as approved by the Commission for Schedule LP.

6. The non-customer specific costs of modifying LG&E's customer billing system to bill customers under the experimental time-of-day rate schedule will be recovered through a charge per kWh billed to customers taking service under Rate LC determined in the same manner as the DSM Cost Recovery Component of LG&E's Demand-Side Management Cost Recovery Mechanism. The cost of modifying LG&E's customer billing system is estimated to be a total of $87,150, or $29,050 annually for three years. The charge would be $0.00001/kWh.

7. The non-customer specific costs of modifying KU's customer billing system to bill customers under the experimental time-of-day rate schedule will be recovered through a charge per kWh billed to customers taking service under Rate LP determined in the same manner as the DSM Cost Recovery Component of KU's Demand-Side Management Cost Recovery Mechanism. The cost of modifying KU's customer billing system is estimated to be a total of $87,150, or $29,050 annually for three years. The charge would be $0.00001/kWh.

8. LG&E will collect any revenue from lost sales from the experimental time-of-day rate schedule through a charge billed to customers taking service under Rate LC determined in the same manner as the DSM Revenue From Lost Sales Component of LG&E's Demand-Side Management Cost Recovery Mechanism. The Revenue From Lost Sales will be determined annually by comparing billings of customers taking service under the experimental time-of-day rate schedule to billings computed under Rate LC for twelve–month periods.

9. KU will collect any revenue from lost sales from the experimental time-of-day rate schedule through a charge billed to customers taking service under Rate LP determined in

the same manner as the DSM Revenue From Lost Sales Component of KU's Demand-Side Management Cost Recovery Mechanism. The Revenue From Lost Sales will be determined annually by comparing billings of customers taking service under the experimental time-of-day rate schedule to billings computed under Rate LP for twelve-month periods.

10. The experimental time-of-day rate schedules will become effective fourteen weeks after the dates of the Commission's Orders in the above-captioned proceedings.

11. The Kroger Co. shall withdraw the direct testimony submitted by Kevin C. Higgins on behalf of The Kroger Co. in Case Nos. 2003-00433 and 2003-00434 and shall not otherwise contest the Companies' proposals in Case Nos. 2003-00433 and 2003-00434 regarding the application of the Merger Surcredits, the shareholder components of the Merger Surcredits, the VDT Surcredits, the shareholder components of the VDT Surcredits, the Companies' proposed revenue increase, or the Companies' proposed allocation of the rate increase.

The parties submit the foregoing stipulation is a fair, just and reasonable resolution of the issues identified herein and request the Commission to determine the resolution of the issues herein based upon the stipulation.

Dated: May 4,2004

Respectfully submitted,

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COUNSEL FOR LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

- and -

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COUNSEL. FOR THE KROGER COMPANY

STANDARD RATE SCHEDULE STOD

Small Time of Day Rate

N

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to commercial customers whose average maximum monthly demands are greater than 250 KW and less than 2,000KW.

a) STOD shall be available as an optional pilot program for three years effective 14 weeks following the Final Order in PSC Case No 2003-00433 for existing customers on Rate LC, Original Sheet No 15, PSC of Kentucky Electric No *6.*
b) As an optional pilot program, STOD is restricted to 100 customers. The Company will notify all eligible customers of STOD and accept applications on a first-come-first-served basis with the beginning of business *6* weeks following the Final Order in PSC Case No 2003-00433.
c) For each year or partial year of the pilot program, programming costs plus lost revenues will be recovered from customers served under Rate LC by a program cost recovery mechanism.
d) No customers will be accepted for STOD following the end of the second year of the pilot program.
e) The Company will file a report on STOD with the Commission within six months of the end of the third year of the pilot program. Such report will detail findings and recommendations.
f) STOD shall remain in effect until terminated by order of the Commission.

RATE
Customer Charge: $80.00 per month

Plus a Demand Charge:
Winter Rate applies to the eight consecutive billing months October through May

Secondary Service -	$11.14 per KW per month
Primary Service -	$ 9.52 per KW per month

Summer Rate applies to the four consecutive billing months June through September

Secondary Service -	$14.20 per KW per month
Primary Service -	$12.32 per KW per month

Plus an Energy Charge of:

On-Peak Energy -	$0.02936 per KWH
Off-Peak Energy -	$0.01370 per KWH

Where the On-Peak Energy is defined for bills rendered during a billing period as the metered consumption from:

a) 10 A.M. to 9 P.M., Eastern Standard Time, on weekdays for the four consecutive billing months of June through September or
b) *8* A.M. to 10 P.M., Eastern Standard Time, on weekdays for the eight consecutive billing months from October through May.

All other metered consumption shall be defined as Off-Peak Energy.

DETERMINATION OF BILLING DEMAND
The monthly billing demand shall be the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period: but not less than 50% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 25 kilowatts (10 kilowatts to any customer served under this rate schedule on March 1, 1964).

STANDARD RATE SCHEDULE — STOD

Small Time of Day Rate

N

PROGRAM COST RECOVERY MECHANISM

The monthly billing amount computed under Rate LC shall be adjusted by the Program Cost Recovery Factor which shall be calculated per KWH in accordance with the following formula:

Program Cost Recovery Factor = (PC + LR) / LPKWH

Where:

a) PC is the cost of programming the billing system and will be no more than $29,050 for each of the three years of the pilot program.
b) LR is the lost revenues of the pilot program calculated by subtracting the revenues that would have been billed under Rate LC from the revenues realized by actual billings under STOD. LR will be calculated for the first program year and applied in the second program or recovery year. That procedure will repeat for each year or partial year the pilot is in effect.
c) LPKWH is the expected KWH energy sales for the LC rate in the recovery year.
d) The Company will file any change in the Program Cost Recovery Factor with supporting calculations ten days prior to application.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 70
Demand Side Management Cost Recovery Mechanism	Sheet No. 71
Environmental Cost Recovery Surcharge	Sheet No. 72
Merger Surcredit Rider	Sheet No. 73
Earnings Sharing Mechanism	Sheet No. 74
Value Delivery Surcredit Rider	Sheet No. 75
Franchise Fee Rider	Sheet No. 76
School Tax	Sheet No. 77

MINIMUM CHARGE

The bill shall in no event be less than the Customer Charge plus the Demand Charge computed upon the billing demand for the month.

LATE PAYMENT CHARGE

The bill will be rendered at the above net charges (including net minimum bills when applicable) plus an amount equivalent to 1% thereof, which amount will be deducted provided bill *is* paid within 15 days from date

EXIT AND EMERGENCY LIGHTING

Where governmental code or regulation requires a separate circuit for exit or emergency lighting, the demand and consumption of such separate circuit may be combined for billing with those of the principal light and power circuit or circuits

TERM OF CONTRACT

For a fixed term of not less than one year and for such time thereafter until terminated by either party giving 30 days written notice to the other of the desire to terminate. A customer exiting the pilot program will not be allowed to return to it until the Commission has issued a decision on the STOD program report.

STANDARD RATE SCHEDULE	STOD
Small Time of Day Rate	

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto N

ELECTRIC RATE SCHEDULE STOD

Small Time-of-Day Service

APPLICABLE

In all territory sewed by the Company.

AVAILABILITY OF SERVICE

Available to commercial customers whose average maximum monthly demands are greater than 250 KW and less than 2,000KW.

a) STOD shall be available as an optional pilot program for three years effective 14 weeks following the Final Order in PSC Case No 2003-00434 for existing customers on Rate LP, Original Sheet No 20, PSC No 13.
b) As an optional pilot program, STOD is restricted to 100 customers. The Company will notify all eligible customers of STOD and accept applications on a first-come-first-served basis with the beginning of business *6* weeks following the Final Order in PSC Case No 2003-00434.
c) For each year or partial year of the pilot program, programming costs plus lost revenues will be recovered from customers served under Rate LP by a program cost recovery mechanism.
d) No customers will be accepted for STOD following the end of the second year of the pilot program.
e) The Company will file a report on STOD with the Commission within six months of the end of the third year of the pilot program. Such report will detail findings and recommendations
f) STOD shall remain in effect until terminated by order of the Commission.

RATE

Customer Charge: $90.00 per month

Plus a Demand Charge:

Secondary Service -	$6.65 per KW per month
Primary Service -	$6.26 per KW per month
Transmission Service -	$5.92 per KW per month

Plus an Energy Charge of:

On-Peak Energy -	$0.02800 per KWH
Off-Peak Energy -	$0.01500 per KWH

Where the On-Peak Energy is defined for bills rendered during a billing period as the metered consumption from:

a) 10 A.M. to 9 P.M., Eastern Standard Time, on weekdays for the four consecutive billing months of June through September or
b) 8 **A.M.** to 10 P.M., Eastern Standard Time, on weekdays for the eight consecutive billing months from October through May.

All other metered consumption shall be defined as Off-Peak Energy.

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average KW demand delivered to the customer during the 15-minute period of maximum use during the month.

The company reserves the right to place a KVA meter and base the billing demand on the measured KVA. The charge will be computed based on the measured KVA times 90 percent of the applicable KW charge.

ELECTRIC RATE SCHEDULE STOD

Small Time-of-Day Service

In lieu of placing a KVA meter, the Company may adjust the measured maximum load for billing purposes when power factor is less than 90 percent in accordance with the following formula:
(BASED ON POWER FACTOR MEASURED AT TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum KW Load for Billing Purposes} = \frac{\text{Maximum Load Measured} \times 90\%}{\text{Power Factor (in Percent)}}$$

PROGRAM COST RECOVERY MECHANISM

The monthly billing amount computed under Rate LP shall be adjusted by the Program Cost Recovery Factor which shall be calculated per KWH in accordance with the following formula:

Program Cost Recovery factor = (PC + LR) / LPKWH

Where:

a) PC is the cost of programming the billing system and will be no more than $29,050 for each of the three years of the pilot program.
b) LR is the lost revenues of the pilot program calculated by subtracting the revenues that would have been billed under Rate LP from the revenues realized by actual billings under STOD. LR will be calculated for the first program year and applied in the second program or recovery year. That procedure will repeat for each year or partial year the pilot is in effect.
c) LPKWH is the expected KWH energy sales for the LP rate in the recovery year.
d) The Company will file any changes to the Program Cost Recovery Factor with supporting calculations ten days prior to application.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 70
Demand Side Management Cost Recovery Mechanism	Sheet No. 71
Environmental Cost Recovery Surcharge	Sheet No. 72
Merger Surcredit Rider	Sheet No. 73
Earnings Sharing Mechanism	Sheet No. 74
Value Delivery Surcredit Rider	Sheet No. 75
Franchise Fee Rider	Sheet No. 76
School Tax	Sheet No. 77

MINIMUM CHARGE

Service under this schedule is subject to an annual minimum of $81.24 per kilowatt for secondary delivery, $77.16 per kilowatt for primary delivery and $73.08 per kilowatt for transmission delivery for each yearly period based on the greater of (a), (b), (c), (d), or (e) as follows:

(a) The highest monthly maximum load during such yearly period.
(b) The contract capacity, based on the expected maximum KW demand upon the system.
(c) 60 percent of the KW capacity of facilities specified by the customer.
(d) Secondary delivery, $812.40 per year; Primary delivery, $1,929.00 per year; Transmission delivery, $3,654.00 per year.
(e) Minimum may be adjusted where customer's service requires an abnormal investment in special facilities.

ELECTRIC RATE SCHEDULE STOD

Small Time-of-Day Service

Payments to be made monthly of not less than **1/12** of the Annual Minimum until the aggregate payments during the contract year equal the Annual Minimum. However, payments made in excess of the amount based on above rate schedule will be applied as a credit on billings for energy used during contract year. A **new** customer or an existing customer having made a permanent change in the operation of electrical equipment that materially affects the use in kilowatt-hours and/or use in kilowatts of maximum load will be given an opportunity to determine new service requirements in order to select the most favorable contract year period and rate applicable. N

DUE DATE OF BILL

Customer's payment will be due within 10 days from date of bill

TERM OF CONTRACT

For a fixed term of not less than one year and for such time thereafter until terminated by either party giving 30 days written notice to the other of the desire to terminate. A customer exiting the pilot program will not be allowed to return to it until the Commission has issued a decision on the STOD program report.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto

Case Nos. 2003-00433 and 2003-00434 – LG&E and KU
Modification of Environmental Surcharge (ECR)

KU

- The rate base, operating expenses, and gross proceeds from by-product and allowance sales included in KU's environmental surcharge associated with its 1994 Compliance Plan ("1994 Plan") will be included and recovered through KU's base rates.

- KU's 1994 Plan will be removed from its environmental surcharge.

- The Base Period Jurisdictional Environmental Surcharge Factor ("BESF) in KU's surcharge will be recalculated to remove the effects of KU's 1994 Plan. The calculation of the revised BESF will be included as part of the first monthly surcharge filing submitted after the removal of the 1994 Plan from the environmental surcharge.

- The costs and allowance expense associated with the sulfur dioxide ("SO_2") emission allowances received from the Owensboro Municipal Utilities will be included as a component of the environmental surcharge costs recovered as part of KU's Post-I994 Plan.

- For KU, any environmental surcharge reporting format that exclusively reports information associated with the 1994 Plan will be deleted from the monthly surcharge filing. For reporting formats presenting information associated with both the 1994 Plan and Post-I994 Plan, the 1994 Plan information will be shown as "0". Reporting formats will be renumbered to reflect the deleted reporting formats during the next surcharge review.

- KU's ES Form 2.31, of Emission Allowances – Current Vintage Year," will no r :e d with th mo / environmental surcharge s KU will continue t include ; Form 2.30, "Inventory of Emission All "

LG&E

- The rate base, rating expenses, and s proce d from d allo sales uded i LG&E's l g associated with its 1995 Compliance Plan (' Plan") will be included and recovered t LG&E's base ates.

- I 995 Plan will be removed f m its environmental urcharge.

- The BESF in LG&E's surcharge will be recalculated t remove the effects of I 1995 Plan. The calculation f the revised BESF will be included as t f the first monthly surcharge filing submitted after the removal of the 1995 Plan from the environmental surcharge.

- For LG&E, any environmental surcharge reporting format that exclusively reports information associated with the 1995 Plan will be deleted from the monthly surcharge filing. For reporting formats presenting information associated with both the 1995 Plan and Post-1995 Plan, the 1995 Plan information will be shown as "0". Reporting formats will be renumbered to reflect the deleted reporting formats during the next surcharge review.

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00434 DATED June 30, 2004

Determination of KU's Jurisdictional Rate Base Ratio
And the Pro Forma Adjustments to KU's Jurisdictional Rate Base

Jurisdictional Rate Base Ratio

The determination of KU's jurisdictional capitalization reflects the allocation of the total company capitalization using an allocation factor based on KU's actual test-year jurisdictional rate base compared to the total company rate base.

	Jurisdictional Rate Base As of 09/30/03	Total Company Rate Base As of 09/30/03
Total Utility Plant in Service	$3,065,995,545	$3,527,901,229
Add:		
Materials & Supplies	57,926,039	66,981,537
Prepayments	2,935,464	3,360,692
Emission Allowances	59,742	69,415
Cash Working Capital Allowance	52,060,201	59,554,982
Subtotal	$ 112,981,446	$ 129,966,626
Deduct:		
Accumulated Depreciation	1,391,726,423	1,600,258,255
Customer Advances	1,455,980	1,504,616
ADIT	244,773,165	286,727,746
SFAS 109 ADIT	(17,891,956)	(19,948,859)
Investment Tax Credit (prior law)	5,453,260	6,519,139
Subtotal	$1,625,516,872	$1,875,060,897
Net Original Cost Rate Base	$1,553,460,119	$1,782,806,958
Percentage of Electric Rate Base to Total Company Rate Base		87.14%

The electric and total company rate base calculations match those submitted by LG&E in Rives Direct Testimony, Rives Exhibit 3, page 1 of 2, with the except of:

- the treatment of Accumulated Deferred Income Taxes ("ADIT"), which are described in the Order;
- the utility plant balances, accumulated depreciation balances, and cash working capital allowances shown in Rives Exhibit 3 did not agree with the KU's Trial Balance, See Response to the Commission Staff's First Data Request dated December 19, 2003, Item 13(a)(b). The Commission has used the balances shown in the trial balance.

APPENDIX D (continued)

Pro Forma Adjustments to KU's Jurisdictional Rate Base

	Post-1994 Environmental Surcharge	E. W. Brown Improvement Reimburse.	SFAS No. 143 Adjustment	Retire Green River Units 1 &2	Commission Expense Adjustments	Total All Pro Forma Adjustments
Total Utility Plant in Service	(137,666,130)	(4,706,912)	(7,408,501)	(18,137,447)	0	(167,918,990)
Add:						
Materials & Supplies	0	0	0	0	0	0
Prepayments	0	0	0	0	0	0
Cash Working Capital	0	0	0	0	(2,206,749)	(2,206,749)
Subtotal	0	0	0	0	(2,206,749)	(2,206,749)
Deduct:						
Accumulated Depreciation	(279,056)	0	0	(17,086,448)	412,065	(16,953,439)
Customer Advances	0	0	0	0	0	0
ADIT	(303,818)	0	0	0	0	(303,818)
SFAS 109 ADIT	0	0	0	0	0	0
Investment Tax Credit	0	0	0	0	0	0
Subtotal	(582,874)	0	0	(17,086,448)	412,065	(17,257,257)
Net Adjustments	(137,083,256)	(4,706,912)	(7,408,501)	(1,050,999)	(2,618,814)	(152,868,482)

All amounts reflect the Kentucky jurisdictional balance.
The adjustments for the Post-1994 Environmental Surcharge, E.W. Brown Improvement Reimbursement, the SFAS No. 143, and the Green River retirements were provided by KU in its response to the Commission Staff's Third Data Request dated March 1, 2004, Item 38.
The Post-1994 Environmental Surcharge adjustment reflects the removal of all rate base-related components. The amounts shown about have been revised to include the ADIT associated with the Post-1994 Environmental Surcharge. When the corresponding adjustment is made to capitalization, the ADIT amount will not be included since ADIT is not funded by capitalization. This treatment is consistent with the Commission's decision in Case No. 1998-00474.
The Commission Expense Adjustments reflect the calculation of the cash working capital allowance using the 1/8th formula and the change in Operation and Maintenance Expenses and the adjustment to depreciation expense as described in the Order.

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00434 DATED June 30, 2004

Determination of KU's Jurisdictional Capitalization

KU's Total Company Capitalization

	Test Year Actual Balances	Updated Capital Structure	Revised TY Actual Balances	Adjustments to Total Company Capitalization	Adjusted Total Company Capitalization
Long-Term Debt	613,712,167	43.69%	729,956,465	(4,822,123)	725,134,342
Short-Term Debt	98,730,542	2.41%	40,265,394	(265,995)	39,999,399
Accounts Receivable Securitization	49,300,000	0.00%	0	0	0
Preferred Stock	40,000,000	2.36%	39,430,013	(260,476)	39,169,537
Common Equity	869,020,543	51.54%	861,111,380	(4,169,442)	856,941,938
Totals	1,670,763,252	100.00%	1,670,763,252	(9,518,036)	1,661,245,216

Adjustments to Total Company Capitalization

	Undistributed Subsidiary Earnings	Investment in Electric Energy, Inc	Other Investments	Minimum Pension Liability	Adjustments to Total Company Capitalization
Long-Term Debt	0	(4,473,454)	(348,669)	0	(4,822,123)
Short-Term Debt	0	(246,762)	(19,233)	0	(265,995)
Preferred Stock	0	(241,642)	(18,834)	0	(260,476)
Common Equity	(8,943,279)	(5,277,221)	(411,317)	10,462,375	(4,169,442)
Totals	(8,943,279)	(10,239,079)	(798,053)	10,462,375	(9,518,036)

APPENDIX E (continued)

KU's Kentucky Jurisdictional Capitalization

	Adjusted Total Company Capitalization	Jurisdictional Rate Base Percentage	Kentucky Jurisdictional Capitalization	KY Juris. Capital Structure	Adjustments to KY Juris. Capitalization	Adjusted KY Juris. Capitalization
Long-Term Debt	725,134,342	87.14%	631,882,066	43.65%	(65,716,597)	566,165,469
Short-Term Debt	39,999,399	87.14%	34,855,476	2.41%	(3,628,339)	31,227,137
Preferred Stock	39,169,537	87.14%	34,132,335	2.36%	(3,553,063)	30,579,272
Common Equity	856,941,938	87.14%	746,739,205	51.58%	(77,655,487)	669,083,718
Totals	1,661,245,216		1,447,609,082	100.00%	(150,553,486)	1,297,055,596

Adjustments to Kentucky Jurisdictional Capitalization

	KY Juris. Capital Structure	Post-1994 Environ. Surcharge	E. W. Brown Repairs	Retire Green River Units 1 & 2	SFAS No. 143 ARO	Adjustments to KY Juris. Capitalization
Long-Term Debt	43.65%	(59,969,458)	(2,054,567)	(458,761)	(3,233,811)	(65,716,597)
Short-Term Debt	2.41%	(3,311,028)	(113,437)	(25,329)	(178,545)	(3,628,339)
Preferred Stock	2.36%	(3,242,335)	(111,083)	(24,804)	(174,841)	(3,553,063)
Common Equity	51.58%	(70,864,252)	(2,427,826)	(542,105)	(3,821,304)	(77,655,487)
Totals	100.00%	(137,387,073)	(4,706,913)	(1,050,999)	(7,408,501)	(150,553,486)

Adjustments to Total Company Capitalization:

The Updated Capital Structure percentages were used to allocate adjustments to Total Company Capitalization on a pro rata basis. The Undistributed Subsidiary Earnings and Minimum Pension Liability impact only the Common Equity, so a pro rata allocation to all components of Total Company Capitalization is not appropriate.

Adjustments to Kentucky Jurisdictional Capitalization:

As noted in Appendix C, the adjustment for the Post-1994 Environmental Surcharge does not include the balance for ADIT, since ADIT is not funded by capitalization.

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00434 DATED June 30, 2004

Schedule of Adjustments

The following adjustments were proposed by KU in its application, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
1. Adjustment to eliminate unbilled revenues.	Sch. 1.00	+$675,000	0
2. Adjust base rates and Fuel Adjustment Clause ("FAC") to reflect a full year of FAC roll-in.	Sch. 1.02	+$1,417,623	0
3. Adjustment to eliminate environ-mental surcharge revenues and expenses.	Sch. 1.03	-$25,039,979	-$248,468
4. Adjust base rate revenues to reflect a full year of the environmental surcharge roll-in.	Sch. 1.04	+$17,986,813	0
5. Eliminate electric brokered sales revenues and expenses.	Sch. 1.06	-$5,571,256	-$7,725,329
6. Eliminate electric ESM revenues collected.	Sch. 1.07	-$4,604,742	0
7. Eliminate ESM, environmental surcharge, and FAC in Rate Refund Account 449.	Sch. 1.08	+$1,630,147	0
8. Eliminate demand-side manage-ment revenues and expenses.	Sch. 1.09	-$2,942,935	-$2,946,471
9. Eliminate advertising expenses pursuant to 807 KAR 5:016.	Sch. 1.15	0	-$45,386
10. Adjustment to remove One-Utility costs.	Sch. 1.18	0	-$1,550,907
11. Adjustment for VDT net savings to shareholders.	Sch. 1.20	0	+$2,895,000

APPENDIX F (continued)

	Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
12.	Adjust VDT-related revenues and expenses to settlement agreement.	Sch. 1.21	+$85,337	-$466,280
13.	Adjustment for merger savings.	Sch. 1.22	-$2,564,269	+$18,968,825
14.	Adjustment to eliminate LG&E/KU merger amortization expense.	Sch. 1.23	0	-$2,726,510
15.	Adjustment for MISO Schedule 10 credits.	Sch. 1.24	0	+$843,344
16.	Adjust for cumulative effect of accounting change. [AG withdrew objection to adjust- ment; AG Post-Hearing Brief at 17]	Sch. 1.25	0	+$8,434,618
17.	Adjustment to remove E. W. Brown legal expenses.	Sch. 1.27	0	-$3,126,995
18.	Adjust for customer rate switching.	Sch. 1.28	-$1,898,980	0
19.	Adjustment for sales tax refunds.	Sch. 1.29	0	+$120,391
20.	Adjustment for 1992 management audit fees.	Sch. 1.32	0	+$163,982
21.	Adjust for prior income tax true-ups and adjustments.	Sch. 1.36	0	+$681,889

APPENDIX F (continued)

The following adjustments were proposed in the application and later revised by KU, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Revision Reference	Change to Revenues	Change to Expenses
1.	Adjust mismatch in fuel cost recovery. [Rives Ex. 1, Sch. 1.01]	Seelye Rebuttal Ex. 2	-$35,887,728	-$28,474,767
2.	Adjust off-system sales revenues for the environmental surcharge calculations. [Rives Ex. 1, Sch. 1.05]	Seelye Rebuttal Ex. 2	-$2,266,829	0
3.	Adjustment to reflect amortization of ESM audit expenses. [Rives Ex. 1, Sch. 1.17]	Scott Rebuttal Ex. 5	0	+$63,933

EXHIBIT__(LK-PSC-13-1)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 10064

O R D E R

TABLE OF CONTENTS

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 10064

O R D E R

On November 20, 1987, Louisville Gas and Electric Company ("LG&E") filed an application with the Commission requesting authority to increase its electric and gas rates for service rendered on and after December 20, 1987. The proposed rates would increase annual electric revenues by $37,794,000, an increase of 8.5 percent, and annual gas revenues by $12,073,000, an increase of 7.27 percent. These increases represent an annual increase in total operating revenues of $49,867,000, or 8.16 percent, based on normalized test year sales. This Order grants an increase in annual gas and electric revenues of $21,993,394 or 3.5 percent.

The Commission suspended the proposed rate increases until May 20, 1988 in order to conduct public hearings and investigations into the reasonableness of the proposed rates. A hearing was scheduled for March 22, 1988 for the purpose of cross-examination of the witnesses of LG&E and the intervenors. LG&E was directed to give notice to its consumers of the proposed rates and the scheduled hearing pursuant to 807 KAR 5:011, Section 8. A hearing to receive public comment and testimony was conducted on

March 7, 1988 at the Jefferson County Courthouse in Louisville, Kentucky.

The Commission granted motions to intervene filed by the Utility and Rate Intervention Division of the Office of the Attorney General ("AG"); Jefferson County ("County"); the City of Louisville ("City"); the Department of Defense of the United States ("DOD"); the Utility Ratecutters of Kentucky, Inc. and the Paddlewheel Alliance, referred to as Consumer Advocacy Groups ("CAG"); the Legal Aid Society, Inc. on behalf of Darlene Baker and Jacolyn Petty, residential customers of LG&E and the Fairdale Area Community Ministries, Inc., the West Louisville Community Ministries, Inc., the Sister Visitors Center, and the Inter-religious Coalition for Human Services, Inc., who assist low-income households ("Residential Intervenors"); and the groups of Alcan Aluminum Company, Ashland Oil Inc., Ford Motor Company, Frito-Lay, Inc., General Electric Company, B. F. Goodrich Chemical Group, Interez, Inc., Reynolds Metals Company, and Rohm and Haas Kentucky, Inc., the Kentucky Industrial Utility Customers ("KIUC").

The hearings for the purpose of cross-examination of the witnesses of LG&E and the intervenors were held in the Commission's offices in Frankfort, Kentucky, on March 22-25, 28-29, 1988 and April 4-8, 11-12, 14 and 18, 1988 with all parties of record represented. Briefs were filed May 9, 1988 and the information requested during the hearings has been submitted.

COMMENTARY

LG&E is a privately-owned electric and gas utility which distributes and sells electricity to approximately 311,600 consumers in Jefferson County, and in portions of Bullitt, Hardin, Meade, Oldham, Shelby, Spencer, and Trimble counties and distributes and sells natural gas to approximately 237,000 consumers in Jefferson County and in portions of Barren, Bullitt, Green, Hardin, Hart, Henry, LaRue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Trimble, and Washington counties.

TEST PERIOD

LG&E proposed and the Commission has accepted the 12-month period ending August 31, 1987 as the test period for determining the reasonableness of the proposed rates. In utilizing the historic test period the Commission has given full consideration to appropriate known and measurable changes.

VALUATION

LG&E presented the net original cost, capital, and reproduction cost as the valuation methods in this case. The Commission has given due consideration to these and other elements of value in determining the reasonableness of the proposed rates. As in the past, the Commission has given limited consideration to the proposed reproduction cost.

Net Original Cost

LG&E proposed a total company net original cost rate base of $1,345,749,137. Generally, the proposed rate base was determined in accordance with the Commission's decision in LG&E's last rate case. The net investment rate base has been adjusted to reflect the accepted pro forma adjustments to operation and maintenance expenses in the calculation of the allowance for working capital. As discussed further in the section of this Order relating to the extraordinary property losses, the net investment rate base has been reduced by $19,571,002 to reflect adjustments to the accumulated depreciation reserve and the deferred income tax accounts. The rate base has been increased by $72,780 to recognize 1 year's amortization of the unprotected excess deferred income taxes resulting from the reduction of the corporate tax rate in the Tax Reform Act of 1986 ("Tax Reform Act"). This is achieved by decreasing the deferred tax reserve account to reflect the amortization adjustment described in the section of this Order relating to Excess Deferred Taxes. All other elements of the net original cost rate base have been accepted as proposed by LG&E.

In LG&E's last rate case, the Commission placed LG&E on notice that the Federal Energy Regulatory Commission ("FERC") rulemaking procedure concerning the calculation of working capital would be considered in LG&E's future rate proceedings. FERC has not moved forward on this matter and at this time has not required a lead-lag study for the calculation of cash working capital. In this case, LG&E has determined the allowance for working capital in the same manner as in past rate cases with cash working capital calculated using the 45 day or 1/8 formula.

Thomas J. Prisco, on behalf of the DOD, recommended the use of the balance sheet approach to calculate working capital. His methodology was based upon correspondence from the National Association of Regulatory Utility Commissioners Annual Regulatory

Studies Program and various accounting books. The Commission agrees with the position of the DOD that consumers should not be required to pay rates which include an allowance for excess working capital. However, based on the evidence presented in this proceeding, the Commission is not convinced that the method offered by the DOD is an accurate representation of the balance sheet approach and, therefore, of LG&E's working capital needs. The Commission has, therefore, determined the allowance for working capital in the same manner as proposed by LG&E using the 45 day or 1/8 formula for cash working capital.

The net original cost rate base devoted to electric and gas operations is determined by the Commission to be as follows:

	Gas	Electric	Total
Total Utility Plant	$196,479,603	$1,702,353,408	$1,898,833,011
ADD:			
Materials & Supplies	1,443,870	46,126,080	47,569,950
Gas Stored Underground	22,166,664	-0-	22,166,664
Prepayments	341,417	1,431,429	1,772,846
Cash Working Capital	4,092,780	31,914,475	36,007,255
Subtotal	$ 28,044,731	$ 79,471,984	$ 107,516,715
DEDUCT:			
Reserve for Depreciation	72,817,435	416,540,389	489,357,824
Customer Advances	2,876,070	1,228,267	4,104,337
Accumulated Deferred Taxes	16,988,797	167,531,323	184,520,120
Investment Tax Credit (3%)	508,000	1,421,030	1,929,030
Subtotal	$ 93,190,302	$ 586,721,009	$ 679,911,311
NET ORIGINAL COST RATE BASE	$131,334,032	$1,195,104,383	$1,326,438,415

Capital

LG&E's Controller, M. Lee Fowler, proposed adjustments to LG&E's $1,362,822,255 end-of-test-year capital of $12,250,000. Long-term debt was adjusted to reflect "(1) the retirement of $12,000,000 of 4 7/8 percent First Mortgage Bonds; Series due September 1, 1987; (2) the scheduled redemption of $250,000 of 1975 Pollution Control Bonds due September 1, 1987; and (3) the refinancing of $49,000,000 of the 9.40 percent Pollution Control Bonds."[1] The refinancing of these Pollution Control Bonds did not affect the level of capital but rather the cost of this item. A further adjustment was made to capital to reflect discounts on preferred and common stock.[2]

Dr. Carl G. K. Weaver, an economist and principal with M. S. Gerber & Associates, Inc. and witness for the AG, proposed a capital balance of $1,246,106,059.[3] The difference between Dr. Weaver's proposed capital and Mr. Fowler's was in (1) Dr. Weaver's use of an October 31, 1987 capital balance as reported in LG&E's Financial and Operating Report; and (2) in the adjustments to reflect discounts on preferred stock and common equity.[4]

Lane Kollen, a utility rate and planning consultant with the firm Kennedy and Associates and witness for KIUC, proposed a

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1 Fowler Prepared Testimony, page 14.

2 Ibid., page 17.

3 Weaver Prepared Testimony, Exhibit CGW, Statement 24.

4 Ibid., pages 35-36.

capital balance of $1,289,422,255.[5] Mr. Kollen used LG&E's proposed adjusted capital balance, but made an additional adjustment to common equity to remove "$61.15 million in excess capitalization which is not utilized to support investment in utility property."[6]

Mr. Kollen provided three arguments for reducing common equity by the $61.15 million. First, because preferred stock has remained unchanged and the long-term debt increase of $51 million in pollution control bonds was invested in utility plant, it is the growth in common equity that has been used to finance short-term investments in non-utility plant since test year end of August 31, 1983.[7] Second, "LG&E has only debt and preferred stock directly attributable to utility operations and none whatsoever for non-utility operations."[8] Third, interest and other income from short-term investments is not flowed through to the ratepayers but is received below the line as a direct benefit to the shareholders.[9]

The process proposed by Mr. Kollen of isolating one asset which is not a part of rate base and reducing capital, without a complete evaluation of other assets and liabilities with regard to rate base and capital valuation is inappropriate. In order to

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5 Kollen Prepared Testimony, Exhibit LK-2.

6 Ibid., page 6.

7 Ibid., pages 8-9.

8 Ibid., page 9.

9 Ibid., page 10.

accept Mr. Kollen's adjustment, a complete reconciliation of the assets and liabilities would be necessary to determine appropriate additions and deletions of assets and liabilities to rate base and capital. None of the parties to this proceeding have attempted to make a complete reconciliation of rate base and capital. In the absence of such thorough analysis, the Commission cannot isolate and adjust selective items as proposed by Mr. Kollen. Moreover, the dollar relationship of rate base and capital as provided in this Order is approximately $4.5 million which is reasonable. The isolated adjustment proposed by Mr. Kollen would result in rate base exceeding capital by approximately $56 million. Therefore, Mr. Kollen's adjustment to capital has not been included for rate-making purposes herein.

The adjustments to the end-of-test-year capital proposed by LG&E reflect actual changes in LG&E's end-of-test-year capital which occurred on September 1, 1987 only 1 day after the end of the test period and should be accepted. In addition, the Commission has adjusted LG&E's capital by $19,571,002 to reflect the extraordinary property losses, which are explained in another section of this Order. Concurrent with its adjustment to the rate base to remove the extraordinary losses, a similar adjustment must be made to capital. A company's net investment in utility operations and capital supporting utility operations should be equal, and rate-making steps should be undertaken to attempt to reach this equality. Since the losses do not relate specifically to any specific component of capital, the most equitable approach is to adjust capital on a pro rata basis. Therefore, the Commission is of the opinion that an adjusted capital balance of $1,331,001,253 is reasonable.

In determining capital the test-year-end Job Development Investment Tax Credit ("JDIC") has been allocated to each component of capital on the basis of the ratio of each component to total capital excluding JDIC, as proposed by LG&E. The Commission is of the opinion that this treatment is entirely consistent with the requirement of the Internal Revenue Service that JDIC receive the same overall return allowed on common equity, debt, and preferred stock.

Reproduction Cost

LG&E presented the reproduction cost rate base in Fowler Exhibit 9. Therein, LG&E estimated the value of plant in service, plant held for future use, and construction work in progress ("CWIP") at the end of the test year. The resulting reproduction cost rate base is $2,542,427,739 which includes electric facilities of $2,174,716,164 and gas facilities $367,810,575.

TRIMBLE COUNTY GENERATING STATION ("TRIMBLE COUNTY") - CWIP

In LG&E's last rate case, as well as the Order issued on October 14, 1985 in Case No. 9243, An Investigation and Review of Louisville Gas and Electric Company's Capacity Expansion Study and the Need for Trimble County Unit No. 1, the Commission put LG&E on notice that the historical treatment of CWIP allowed in previous cases should not be taken as an indication that the treatment would continue indefinitely in future cases. In addition, due to the uncertainties surrounding the Trimble County project, the Commission initiated monitoring procedures to keep abreast of the

Trimble County activity. This monitoring contributed to the establishment of Case No. 9934, A Formal Review of the Current Status of Trimble County Unit No. 1.

In the Order in Case No. 9934 entered on July 1, 1988, the Commission found that 25 percent of Trimble County should be disallowed. In this proceeding, the Commission has heard evidence with regard to the rate-making treatment of Trimble County CWIP; however, there has been no specific testimony offered regarding the various options for rate-making treatment of a disallowance of 25 percent of the cost of Trimble County. Furthermore, in Case No. 9934, since the Commission's decision is being issued concurrently with this Order, there has been no specific investigation of the revenue requirement effects of a 25 percent disallowance of Trimble County. Therefore, the Commission has determined that another proceeding will be established to allow a full investigation of this issue. An Order establishing this case will be rendered in the immediate future.

In order to protect the interests of the consumers and assure that the disallowance will be recognized from the date of this Order, the Commission is of the opinion that all revenues associated with additions to CWIP since LG&E's last rate case should be collected subject to refund. The Trimble County CWIP included in rate base in LG&E's last rate case was $268 million and Trimble County CWIP has achieved a level of $382 million at the end of the test period in this case. Applying the overall rate of return allowed in this case to the increase in Trimble County CWIP of $114 million results in an annual provision of $11.4 million to be collected subject to refund. The final amount of disallowances will be determined in the forthcoming Trimble County CWIP case soon to be established and the current ratepayers will realize the benefits of the disallowance when an Order is issued in that case.

In this proceeding, as in LG&E's last two rate cases, the Commission has addressed the issue of continuing the practice of allowing CWIP in LG&E's rate base. While both LG&E and the intervenors have presented arguments supporting and opposing the practice of allowing a return on CWIP, neither side has presented any new arguments or evidence which has not already been considered by this Commission. Consequently, based on the evidence in this case, the Commission is of the opinion that the present regulatory treatment of allowing a cash return on CWIP should continue in light of the decision to complete Trimble County. However, the final amounts utilized for rate-making and revenue requirement determination will be decided in the future proceeding announced in this section of the Order.

RETIREMENTS OF SULFUR DIOXIDE REMOVAL SYSTEMS ("SDRS") AND GAS PLANT

As part of this case, the Commission Staff reviewed LG&E's accounting treatment for the retirement of SDRS and three underground storage fields ("gas fields"). The Staff gave LG&E notice through cross-examination and data requests that the accounting treatment utilized by LG&E ignored the impact these retirements had on LG&E's rate base and the return on that rate base.[10] LG&E

[10] Response to the Commission Orders dated December 23, 1987, Item No. 42(a-e); dated January 15, 1988, Item No. 69; and Hearing Transcript, Vol. IV, pages 7, 13-19.

initially advised the Staff in 1986 that it planned to account for the abandoned gas fields as a normal retirement under the Uniform System of Accounts ("USoA"). The accounting treatment was investigated in this case because this was LG&E's first general rate case since these retirements had taken place.

LG&E stated that this accounting treatment was its usual procedure in accounting for abandonments and retirements.[11] In addition, LG&E determined that these entries resulted in a depletion of the depreciation reserve which was now deficient. LG&E proposed to revise upward the depreciation rates for underground gas plant to eliminate the deficiency. The revision was made in 1986, with the depreciation rate for underground gas plant increasing from 3.37 percent to 5.05 percent.[12]

The abandoned gas fields were comprised of several million dollars of undepreciated plant per the company's books. While most of the gas fields were being depreciated over approximately 30 years, significant portions of the gas fields had been in service less than 15 years. As a result of the abandonment, LG&E reported an income tax loss of $3,973,815[13] in 1985. Preliminary figures supplied by LG&E indicated that a book loss, at least as great as the tax loss, existed.[14]

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[11] Response to the Commission Order dated December 23, 1987, Item No. 42(a), page 1 of 2.

[12] Ibid., dated January 15, 1988, Item No. 69(f)(3), page 3 of 3.

[13] 1985 FERC Form No. 1, Annual Report of LG&E, page 261.

[14] Response to the Commission Order dated January 15, 1988, Item No. 69(f)(1), page 2 of 37.

During 1986, Commission Staff obtained information from LG&E which reflected that early retirements of SDRS units were significant and had been accounted for in the same manner as the abandoned gas fields.[15] It was apparent that a depletion of the electric steam production plant depreciation reserve resulted. Since the accounting treatment for these early retirements results in a material impact on revenue requirements, the Commission is of the opinion that this subject is appropriately an issue in this case.

The subject of these early retirements and abandonments has been thoroughly explored through information requests and in cross-examination of LG&E witness, Mr. Fowler. From the information requests, it was determined that for the period 1984 through 1986, LG&E had incurred losses of $21,052,354 due to the early retirements of SDRS units and losses of $6,862,820 due to the abandonment of the gas fields in 1985.[16] If the electric and gas losses are combined, the total losses on these early retirements are $27,915,174. LG&E claimed tax losses on the SDRS units retired between 1984 and 1986 of $3,029,756.[17]

LG&E objected to the questioning of Mr. Fowler on the grounds that the accounting treatments utilized for the SDRS units and gas fields were not relevant to its rate application. LG&E observed that the events did not occur in the test year, and it believed

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[15] Ibid., Item No. 69(f)(2 and 3), page 1 of 3.

[16] Ibid., Item No. 69(f)(1), page 2 of 37.

[17] Ibid., Item No. 69(a), page 1 of 4.

that it was not a proper issue for consideration in this case.[18] The Commission finds that even though the actual retirements and abandonments did not occur in the test year, the subject is highly relevant to this rate case. The impact of retirements losses totaling $27,915,174 exists in the accumulated depreciation reserve and thus is reflected in the net original cost rate base. LG&E has already revised its depreciation rates for underground gas storage plant to offset a portion of the loss and seeks to reflect that change in this case. Moreover, the accounting treatment employed by LG&E does not properly disclose the impact of the early retirements and allows LG&E a full return on the net amount of the losses while the losses are being recovered through depreciation accruals.

LG&E's approach to the retirements transactions, on the surface, is simple and straightforward. While book losses generated by early retirements and abandonments can produce deficiencies in the accumulated depreciation reserve, the increasing of depreciation rates on existing plant will make up the deficiency. Mr. Fowler pointed out that, under LG&E's use of whole life, functional group depreciation, utility plant will often be depreciated beyond the estimated service life and thus can help reduce any existing deficiency.[19]

However, LG&E has failed to recognize that its approach allows the company to reap a double benefit at the ratepayers'

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18 Hearing Transcript, Vol. III, pages 177-178.

19 <u>Ibid</u>., Vol. IV, page 12.

expense. While plant is in service, a company will usually receive a return on the plant and recover the cost of the plant. This is accomplished through the return on the rate base and depreciation expense. LG&E seeks to retain this arrangement on plant that has been retired or abandoned. This approach not only allows for recovery of the inherent deficiency in accumulated depreciation through depreciation expense, but also allows a return on the loss by overstating the rate base. LG&E has maintained that its current treatment benefits its ratepayers by the reserve deficiencies being made up over several years, rather than recovered over a 3- to 5-year period. LG&E contends that 3 to 5 years is a normal amortization period for extraordinary losses, but Mr. Fowler could not cite a publication or pronouncement that supported this claim.[20]

The Commission recognizes that one of the problems which causes this situation is that general plant accounting instructions contained in the USoA does not specifically provide for the possibility of a loss occurring at the time of any retirement. There are three types of property losses provided for in the USoA: losses arising from the disposition of future-use utility plant; losses on the sale, conveyance, exchange or transfer of utility or other property to another; and extraordinary property losses. This last type of loss requires the creation of a deferred debit in Account No. 182, Extraordinary Property Losses.[21] The

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20 Ibid., Vol. III, pages 188-189; Vol. IV, pages 22-23, 51-52.

21 USoA, Electric and Gas Plant Instructions, Item No. 10, parts E and F.

amortization of the account over a set period of years is anticipated in USoA instructions.

In the absence of specific accounting treatment in the USoA, the Commission may utilize other authoritative accounting sources. The Commission generally attempts to minimize discrepancies between generally accepted accounting principles ("GAAP") and its prescribed accounting treatment. Under GAAP applied to non-utility business enterprises, the possibility of a loss occurring at the time of retirement of an asset is specifically recognized. Under those standards, when a major asset is retired from use, the cost and related accumulated depreciation are removed from the accounts, which is similar to the approach outlined in the USoA. However, under GAAP, the charge to accumulated depreciation is limited to the depreciation provided on the asset and since the depreciation expense charged over the estimated useful life of the asset is only an allocation of the cost based on an estimate, a gain or loss will normally be realized on disposal of the asset.

It is conceivable that in GAAP accounting for non-utility enterprises, the practice of group depreciation would exist in which case the entity would account for an asset retired from service in the same manner as prescribed in utility accounting. Thus, it is apparent that another discrepancy in dealing with this issue lies in the eligibility of an asset for group life depreciation. The Commission is of the opinion that the assets here, the gas fields and the SDRS units, are of sufficient value and identifiable enough to warrant individual asset accounting treatment for depreciation and retirement accounting. Thus, the arguments with regard to group depreciation are not valid.

Of the three types of treatment of losses available to LG&E under the USoA, the only applicable treatment is the extraordinary property loss. To be considered extraordinary, the transaction must be of significant effect, not typical or a customary business activity, and would not be expected to recur frequently or be considered as a recurring factor in the evaluation of the ordinary operating process of the business.[22] These restrictions are similar to those prescribed under GAAP. In Accounting Practices Board ("APB") Opinion 30, an extraordinary item is defined as a transaction which is of an unusual nature and has an infrequency of occurrence given the environment in which the business operates.[23] Under the current USoA, the use of extraordinary treatment must be approved by the Commission, upon the request of the company.

Based on the information contained in the record, the Commission finds that the early retirements and abandonments constituted extraordinary property losses, and that LG&E should have requested such treatment. The size of the book losses for the SDRS units and gas fields would be considered significant. LG&E has been an industry leader in SDRS technology, a technology which was new and for which service life history was nonexistent. Mr. Fowler stated at the hearing that the company's experience with SDRS units was

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22 Ibid., Item No. 7.

23 APB Opinion 30, paragraph 20.

unusual.[24] The gas fields were abandoned based on the recommendations of a consultant hired by LG&E.[25] While the USoA requires the company to seek Commission approval for the use of extraordinary treatment, the lack of such action on the part of LG&E causes the initiative to shift to the Commission.

It appears that LG&E has failed to recognize the impact its approach has on accounting and rate-making treatments. The use of revised depreciation rates on existing total utility plant is an example of the accounting impact. It is understandable that depreciation rates need to be revised from time to time due to changes in the actual service life history and technological advances. However, increasing the depreciation rates on existing plant to recover deficiencies created by early retirement or abandonment of major items of plant is not justifiable in this instance. If depreciation rates should be increased to make up deficiencies resulting from extraordinary property losses, once the deficiencies are made up the rates should be revised downward. With regard to the rate-making impact, the accumulated depreciation reserve is understated until the reserve is restored by the increased depreciation resulting from the depreciation rate revision. The understated accumulated depreciation reserve in turn causes the net original cost rate base to be overstated. Thus, if the revenue requirement is based on the return granted on

24 Hearing Transcript, Vol. III, pages 179-180, 190-191.

25 Response to KIUC's Second Data Request filed February 1, 1988, Item No. 16.

rate base, the revenue required is inflated due to the overstated rate base.

In addition to the impact of the deficiencies in the accumulated depreciation reserve, there is also the issue of the rate-making treatment of deferred income taxes generated by the retired assets. LG&E was asked to provide the deferred income tax balances related to the SDRS units and the gas fields. For the gas fields, LG&E was able to respond that at the date of abandonment deferred income taxes totaled $3,059,100, and that $162,000 had been flowed back by the test year-end, for a balance of $2,897,100.[26] For the SDRS units, LG&E continually stated that this deferred income tax figure could not be readily determined due to the manner in which its deferred tax accounts were maintained. LG&E has identified the total SDRS deferred income tax balance as $4,910,100 at the date of retirement,[27] $5,146,000 at test year-end,[28] and $5,268,800 at calendar year-end 1987.[29] In addition, LG&E stated these figures included the impact of any flowbacks of these taxes. In calculating the balances, LG&E frequently speaks of "presumed retirement dates," and that in some cases, tax depreciation continues after retirement.[30] These

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26 Supplemental Hearing Data Request, filed May 17, 1988, page 4.

27 Response to the Commission Order dated January 15, 1988, Item No. 69(d)(1).

28 Supplemental Hearing Data Request, filed May 17, 1988, page 2.

29 Ibid., filed May 10, 1988, page 1.

30 Ibid., filed May 10 and 17, 1988, page 1.

retirements have occurred, there is no presumption involved. Also, LG&E has not cited references to the Internal Revenue Code to support its claim that tax depreciation can be taken after the retirement of the depreciated asset. Based on the information supplied by LG&E, the Commission believes the most accurate deferred income tax balance for the SDRS units is $4,910,100, the reported balance at the time of the retirement.

In its brief, LG&E proposed that if the Commission required it to recognize the losses as extraordinary and establish regulatory assets, that the regulatory assets should be amortized over a period of 5 years.[31] However, Mr. Fowler stated that, utilizing a 5-year amortization period, the revenue requirements generated under the extraordinary loss proposal would be higher than those generated using LG&E's original accounting and rate-making treatment of the retirements.[32]

The Commission believes that the approach proposed by LG&E in this situation is not proper. The Commission believes that in the situation of the early retirement of the SDRS units and the abandonment of the gas fields, LG&E should have sought extraordinary property loss treatment for these transactions. LG&E's assumption that early retirements are offset by late retirements may be true for certain assets which qualify for group depreciation, but not in the current situation which demonstrates the basic problems of the assumption with regard to the plant retirements in question.

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31 LG&E Brief, filed May 9, 1988, page 44.

32 Hearing Transcript, Vol. IV, pages 14-15.

The dollar magnitude of these retirement losses should not be made up by LG&E by "over depreciating" current assets, since this would result in excessive recovery under ordinary rate-making practices and is not an appropriate criterion on which to base a change in depreciation rates.

Therefore, the Commission hereby requires the extraordinary property loss treatment for the losses experienced with the early retirement of the SDRS units and the abandonment of the gas fields. As such, the accumulated depreciation reserves for both the electric and gas plants should be credited $21,052,354 and $6,862,820, respectively. The debit should be to Account No. 182, Extraordinary Property Losses, with electric and gas subaccounts maintained. The deferred income tax accounts should be debited $4,910,100 for electric and $2,897,100 for gas. The corresponding credits will be to the appropriate subaccount of Account No. 182. The ratepayers of LG&E have provided the dollars represented in the deferred income tax balances. The netting of the total loss to be amortized recognizes this fact.

In determining a proper amortization period, the Commission has considered the undepreciated balance of the assets retired, the impact on operating expenses, and the ultimate effect on the ratepayers and stockholders. The Commission is of the opinion that an amortization period of 19 years is reasonable for the electric extraordinary property loss and that 18 years is reasonable for the gas extraordinary property loss. This represents an approximation of the number of years of the remaining service lives on the assets retired which LG&E had utilized for book depreciation purposes. Had LG&E's approach proposed in its Brief been utilized, with no change in the depreciation rates, it would have recovered the losses approximately over the same period of time. An annual amortization expense of $849,592 for the electric and $220,318 for the gas has been included for revenue requirement determination herein.

The company's proposal to increase the gas depreciation by $211,035 is unnecessary and the gas depreciation expense has been adjusted to reflect the depreciation expense based on the 3.37 percent depreciation rate in effect before the gas field abandonment. The income tax impacts of these adjustments have been included in the calculation of book income tax expense. The net-original cost rate base has been adjusted by $19,571,002 to reflect the accounting entries to the accumulated depreciation reserve and the deferred income tax accounts. The electric rate base has been reduced by a net amount of $16,142,254 reflecting the $21,052,354 increase to electric accumulated depreciation and reduced by the $4,910,100 reduction to electric deferred income taxes. The gas rate base has been reduced by a net amount of $3,428,748 reflecting the $6,862,820 increase to gas accumulated depreciation and reduced by the $2,897,100 reduction to gas deferred income taxes and the $536,972 reduction to gas depreciation expense due to the depreciation rate adjustment.

MANAGEMENT AUDIT OF LG&E

In August 1986, the Commission's Management Audit of LG&E ("Management Audit") was completed. The audit was performed by Richard Metzler and Associates, Inc. and Scott Consulting Group

("RM&A/Scott") under a statute enacted by the Kentucky General Assembly. According to the Executive Summary, the potential cost avoidance or reduction identified during the audit is probably in excess of $6 million to $7 million in annual recurring and $9 million to $10 million in one-time cost savings.[33] RM&A/Scott developed implementation action plans ("Action Plans") for each of the 146 recommendations and LG&E was directed to provide semi-annual reports to the Commission on the implementation of the recommendations.

This is LG&E's first request for a general increase in rates since the completion of the Management Audit. In prepared testimony, Robert L. Royer, President and Chief Executive Officer of LG&E, and Fred Wright, Senior Vice-President of Operations, noted that LG&E had incurred substantial expenditures to implement the Management Audit recommendations. The Commission demonstrated concern regarding the costs and benefits resulting from the Management Audit through the numerous information requests submitted to LG&E. LG&E was requested to provide a witness at the hearing for cross-examination regarding the Management Audit.

This section will focus on four general areas of the audit identified by the following subsections.

1. Closed Recommendations.
2. Management Information Systems.
3. Work Force - Compensation Recommendations.
4. Open Recommendations.

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33 Management Audit of LG&E, Executive Summary, II-13.

Closed Recommendations

In response to the Commission Order dated January 15, 1988, F. L. Wilkerson, Vice-President of Corporate Planning and Accounting for LG&E, provided information regarding the cost and savings of 45 audit recommendations which have been implemented and closed.[34] The response indicated that the test year included $510,300 to $535,300 in costs associated with these recommendations and that the estimated recurring costs were in the order of $719,500 to $749,500. The estimated savings associated with these recommendations actually quantified in that response was related to only 2 of the 45 closed recommendations and totaled $167,000. During cross-examination, Mr. Wilkerson indicated that it is difficult to quantify the savings for this group of recommendations and that the savings, for the most part, were not measurable.[35] As a result, LG&E was requested to file additional information which would provide a description of the nature of the costs included in the test year, identify the type of savings or benefit and the functional area in which the savings will occur, and indicate whether the benefits will be one-time or recurring in nature.

The Commission has reviewed the information filed relevant to these closed recommendations and finds that the actions taken by LG&E in association with the implementation of these recommendations are in the interests of LG&E's consumers. The Commission is

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[34] Response to the Commission Order dated January 15, 1988, Item No. 5.

[35] Hearing Transcript, Vol. VIII, pages 194-195.

however, concerned with LG&E's failure to quantify the savings and/or benefits associated with implementation of audit recommendations and particularly with the level of estimated recurring costs. In future rate proceedings, LG&E should be better prepared to support the recurring costs associated with closed recommendations in order for the Commission to be able to better determine their reasonableness in light of the associated savings and/or benefits.

Management Information Systems

In response to Item Nos. 1(a) and (b) of the Commission Order dated December 23, 1987, LG&E provided a discussion of its efforts to develop or enhance its major management information systems. The actual development of most of these systems was begun prior to the Management Audit.[36] However, the Management Audit includes numerous recommendations relating to these systems.

The test year includes operating expenses of approximately $2,476,000 associated with development of these systems. LG&E has estimated that they will incur additional costs of $2,421,000 over the 12-month period ending August 31, 1988.[37] Additionally, LG&E has indicated that the estimated expenditures at the completion of the development of these systems will be $11,711,000 operating and maintenance costs and $2,327,000 capital costs.[38]

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36 Ibid., page 208.

37 Response to the Commission Order dated December 23, 1987, Item No. 1(a).

38 Response to Hearing Information Request, Item No. 3, Response 7.

The Executive Summary of the Management Audit addresses, in general terms, the status of LG&E's business systems and indicates that 3 to 5 years will be required to bring LG&E's computer-based systems up to par with the industry.[39] In response to a request for information made during the hearing, LG&E filed documentation indicating that the systems would be completed beginning in 1988 and continuing through 1991.[40] That response also indicated that the development of some of these systems began as early as 1983. Additional information in the record indicates these systems are still under development and that benefits that may result have not yet been realized. Further, LG&E has indicated that any savings or benefits are not likely to exceed the costs during the immediate future.[41]

LG&E was questioned regarding any cost-benefit analysis performed in connection with these systems and the appropriateness of expensing rather than capitalizing the cost of developing these systems. Cost-benefit analyses of the management information systems, though requested, have not been filed in this proceeding and it is not clear if LG&E has prepared updated cost-benefit analyses as projects progress.[42] Mr. Wilkerson indicated that LG&E felt that it was appropriate to expense the development costs

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39 Management Audit of LG&E, Executive Summary, II-7 to II-8.

40 Response to Hearing Information Request, Item No. 3, Response 7.

41 Response to the Commission Order dated December 23, 1987, Item No. 1(b).

42 Hearing Transcript, Vol. VIII, page 218.

of these systems because LG&E is paying for those costs in today's dollars, because the systems cost money up front, and because unless the company is willing to spend the money no savings will result. Mr. Wilkerson cited a paragraph relating to cost reduction penalties from the Executive Summary as support for LG&E's position.[43] This paragraph however does not address the accounting or rate-making treatment associated with the costs, and includes no prohibition in regard to capitalization of development costs.

The Commission is of the opinion that for the purpose of determining revenue requirements in this proceeding, the test-year operating expenses should be decreased by the $2,475,092 associated with the development costs of the management information systems. The management information systems are being developed to provide benefits to LG&E and its customers over an extended period time. LG&E should begin subsequent to the date of this Order to capitalize and amortize, over a reasonable time period, development costs associated with the management information systems. The costs incurred during and prior to the test year have been expensed during those accounting periods. Therefore, no adjustment to rate base is necessary. The rate-making treatment of costs, capitalized subsequent to the date of this Order, will be considered in future rate proceedings.

<u>Work Force - Compensation Recommendations</u>

The Management Audit contained numerous recommendations relating to the organization structure, work force, and compensation and benefits programs of LG&E. The Executive Summary noted that LG&E could produce annual payroll savings of at least $2.5 million by implementing work force recommendations exclusive of Trimble County considerations.[44] The Management Audit indicated that these savings can be accomplished by:

> . . . increasing organizational productivity through the establishment of work management systems, reducing layers of management, increasing spans of managerial control and revising the personnel skill mix . . .[45]

In addition, specific recommendations instructed LG&E to review the compensation and benefit programs and to annually review health insurance and other benefits programs.

These recommendations are of particular concern to the Commission for several reasons. First, the proposed $5,390,668 increase to test-year operating expenses for labor and labor-related costs was the largest single adjustment proposed by LG&E excluding the adjustments for electric weather normalization and fuel expenses. Second, LG&E was notified in its last rate proceeding, wherein it proposed an increase of $558,000 for Blue Cross-Blue Shield insurance, of the Commission's intended review in the next rate proceeding. In this case, $1,224,561 or approximately 23 percent of the proposed labor and labor-related increase is for health insurance. Third, the level of LG&E's employees has

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43 Ibid., pages 239-240.

44 Management Audit of LG&E, Executive Summary, II-13.

45 Ibid.

been steadily increasing, from 3,646 in 1985[46] to 3,920 on September 6, 1987 and to 3,988 on November 15, 1987.[47]

Moreover, when all of these work-force related recommendations are considered as a whole, they indicate the need for a thorough, comprehensive evaluation of LG&E's organizational structure, and compensation and benefit packages. According to LG&E, the review of the organizational structure, including work force considerations, has begun and LG&E should be able to meet the 3- to 5-year time frame for completion cited in the audit. The Commission is concerned with LG&E's progress in implementing the work-force reduction recommendation of the Management Audit. In August 1986, the Management Audit Report recommended that a reduction in LG&E's work force of 50 to 200 personnel over a 3- to 5-year period exclusive of the Trimble County construction should be accomplished. In response to the recommendation on October 31, 1987 LG&E promulgated its Human Resources Control Program essentially freezing the level of employment on that date and stating a company goal of reducing employment overall. Though LG&E is apparently implementing the planning mechanism called for in the Management Audit, the Commission is concerned with the continued expansion of its work force and the speed at which LG&E is implementing its employment control program. During the period from December 1986 to November 1987, LG&E expanded its work force

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46 Management Audit of LG&E, Chapter XI, Human Resources Management, Exhibit XI-10, Staffing Trends by Employee Group (1975-1985).

47 Response to the Commission Order dated January 15, 1988, Item No. 14.

exclusive of Trimble County from 3,162 to 3,210. The trend in employment is contrary to the intent of the auditors' recommendation and at the very least requires a more detailed explanation than has been provided by LG&E as to the reasons for the work force expansion. The Commission will continue to monitor the non-Trimble County level of employment in the future and will require LG&E to provide a complete explanation for any change in the work force on a semiannual basis. This initial report should be provided to the Management Audit Section starting October 31, 1988.

During the test year, LG&E developed a benefit improvement package for nonunion employees, granted the officer group salary increases greater than would normally have been considered and improved the supplemental benefits authorized for officers.

The improvements for the officer group were intended to address salary compression, and compensation and benefit levels lower than industry averages. LG&E has indicated that the incremental cost of the improvements for this group is between $40,900 and $50,200 for the test year. The benefit improvement package instituted by LG&E included changes in health insurance and group life insurance, and added a thrift-savings plan. This package is of particular concern to the Commission because of the impact on test year costs and the overall level of fringe benefits.

LG&E was notified in Case No. 8924, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated May 16, 1984, of the Commission's intention to review health insurance costs in the next rate proceeding. In addition, the Management Audit contains recommendations directing LG&E to evaluate the compensation and benefit programs and to review health insurance and other benefits programs to ensure cost effectiveness. Mr. Wilkerson, during cross-examination, indicated that the benefit improvement package was not instituted in response to the Management Audit, but for other reasons, among them, maintaining the nonunion benefits comparable to the union employees.[48]

William H. Hancock, Jr., Senior Vice-President of Administration and Secretary of LG&E, presented testimony regarding health insurance and other fringe benefits. He discussed the health insurance cost containment measures taken by LG&E and the newly instituted flexible medical benefit plan. Hancock Exhibit 1 indicates that the rate of increase after cost containment for Blue Cross-Blue Shield insurance was 1.4 percent compared to a rate of 12.8 percent prior to cost containment.[49] Hancock Exhibit 2 reflects an increase in average cost per participant of 29 percent from August 1983 to August 1987 as compared to an industry trend factor of 63 percent over 4 years.[50] These exhibits provide the basis of support regarding LG&E's attempts to control health insurance costs. However, for the 2 years immediately following the institution of the cost containment measures the rate of

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48 Hearing Transcript, Vol. VIII, pages 223-224.

49 Hancock Prepared Testimony, Exhibit 1.

50 <u>Ibid</u>., Exhibit 2.

increase is above 10 percent per year.[51] In addition, the basis of the 63 percent industry trend factor was a letter from an actuarial consultant[52] which neither defines the precise calculation of the factors nor the region considered. The only evidence by which the success of LG&E's cost control efforts can be compared to other utilities or companies in the area that LG&E serves or the state is this ambiguous letter from the actuarial consultant.

Mr. Hancock's testimony indicates that the annual reduction in medical benefits resulting from the flexible benefits program is approximately $500,000.[53] However, the savings are offset by a 3-year cash incentive payment to employees switching to the plan. The test-year operating expenses include $196,408 associated with the payment of the cash incentive for the first year. However, this is only the amount not paid in cash but contributed to the new thrift savings plan. The employees electing to receive actual cash payments received those payments in December 1987 after the end of the test period.

In the Management Audit Action Plan Progress Reports ("Progress Reports") submitted to the Commission in November 1986, LG&E indicated that the company was working with a consultant to evaluate alternate benefit packages and would submit a proposal to

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51 Response to the Commission Order dated December 23, 1987, Item No. 5(d).

52 Response to KIUC First Information Request dated January 14, 1988, Item No. 8, page 2.

53 Hancock Prepared Testimony, page 4.

senior management for consideration.[54] The record in this case contains no evidence that LG&E made any evaluations with regard to any fringe benefits other than health insurance. However, on April 1, 1987, LG&E instituted the new benefit improvement package which will increase LG&E's expenses.

The Commission stated its concern in LG&E's last rate case regarding the level of Blue Cross-Blue Shield insurance. Furthermore, the management auditors recommended that LG&E review, not only health insurance, but the total benefits package. The Commission's and the auditors' concern in this area would require that LG&E provide more adequate support than that which has been included in this proceeding to justify the cost increases to be borne by the ratepayers. Therefore, the Commission is of the opinion that the cost of the change in group life insurance, the cost of the thrift savings plan, and the cost of the cash incentive payments should not be borne by LG&E's ratepayers. The effect of these changes on LG&E's test year costs is specified in the later section of this Order dealing with the proposed labor and labor-related adjustments.

Open Management Audit Recommendations

During cross-examination, Mr. Wilkerson was asked to provide budget projections which reflect the future costs for the projects that were being implemented pursuant to the Management Audit. Mr. Wilkerson responded that the 90 or so open recommendations had not been identified in the budget process and were not readily

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[54] Management Audit Action Plans, November 1986, XI-8, page 2.

identifiable.[55] LG&E is hereby placed on notice that in future rate proceedings, the company should be prepared to identify and provide the costs associated with Management Audit recommendations. Due to LG&E's current inability to track these costs and its failure to adequately support, with proper documentation, the claim that post-test year costs will be incurred at the same level as the test year, the Commission finds that the costs associated with the open recommendations should not be included in the determination of revenue requirements.

The test year costs associated with these recommendations were provided in response to Item No. 1 of the Commission's Order dated January 15, 1988. The calculation of the amount disallowed, which is approximately $258,000, is included in a later section of this Order.

Summary

The Commission compliments LG&E on the progress it has made in the implementation of its Action Plans. The Commission continues to have confidence in the benefits that both LG&E and its consumers can derive from proper implementation of its Action Plans. However, the Management Audit, Action Plans, and Progress Reports do not absolve management from its responsibility to continuously monitor and document both the costs and benefits from implementing the recommendations of the management auditors. In future rate proceedings, LG&E should be better prepared to

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55 Hearing Transcript, Vol. IX, pages 76-77.

identify implementation costs, ongoing costs, as well as benefits resulting from implementation of its Action Plan.

REVENUES AND EXPENSES

For the test period, LG&E had actual net operating income of $118,858,318. LG&E originally proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions which resulted in an adjusted net operating income of $111,795,250.[56] Subsequent to its original filing, LG&E proposed several correcting adjustments, which are addressed herein. The Commission is of the opinion that the proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications.

Temperature Normalization - Electric

LG&E proposed an adjustment to electric revenues and expenses for deviations from normal temperatures. The proposed adjustment would reduce operating income by $7,673,763 based on the assumption that the test year included an excess of 402 cooling degree days ("CDD") and a deficiency of 362 heating degree days ("HDD").

An electric temperature normalization adjustment has been proposed in each of LG&E's past three rate applications. In Case No. 8284, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated January 4, 1982, and Case No. 8616, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated March 2, 1983, the adjustment was proposed by LG&E; however, in Case No.

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56 Fowler Prepared Testimony, Exhibit 4.

8924, the adjustment was proposed by an intervenor. The Commission denied the proposed adjustments in each case. In his oral testimony, Patrick Ryan, a Load and Economic Research Analyst with LG&E, summarized the concerns expressed by the Commission in those past cases and stated that the methodology presented in this case addressed those concerns and was the most appropriate way to make this type of adjustment.[57]

This adjustment accounts for 15.4 percent[58] of LG&E's overall requested revenue increase. Additionally, Mr. Ryan has stated that if LG&E's rates are based on excess KWH sales, LG&E's only opportunity to recover its revenue requirement is if the test-year weather pattern occurs in each succeeding year.[59] However, this statement covers only one part of the Commission's concern with the proposed adjustment and the converse of this statement must also be considered. That is, if revenues are based on below normal sales, then consumers will be paying rates that may generate revenue in excess of authorized revenue requirements. Thus, prior to acceptance, it is imperative that the Commission determine if LG&E has accurately reflected the relationship of KWH sales and temperature.

LG&E's methodology begins with the definition of normal weather and the determination of the difference between normal (or expected) weather and actual test year weather. For purposes of

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57 Hearing Transcript, Vol. V, pages 9-11.

58 Ryan Prepared Testimony, page 4.

59 Ibid.

calculating the weather adjustment, actual and normal degree day data, the measures of weather used in this analysis were converted from a calendar month basis to that of billing cycles. Because LG&E bills its customers in cycles, it was necessary to calculate both billing cycle days and billing-cycle degree days to match weather data with sales data.

In determining normal billing-cycle degree days, LG&E used the National Oceanic and Atmospheric Administration's ("NOAA") 1951-1980, 30-year average degree day data. By using this average, LG&E has failed to include the degree day data from the most recent 7 years. The Commission is aware from a review of NOAA literature that the NOAA will prepare special HDD or CDD tabulations or other summaries which would include more recent data.[60] However, at the hearing, LG&E indicated that no attempt has been made recently to contact the NOAA to try to get more current degree day normals.[61] The Commission's language in its Order in Case No. 8616 clearly states that current data should be used to define normal degree days:

> A current [emphasis added] 30-year period provides accurate up-to-date information and at the same time is long enough to mitigate any abnormalities in weather conditions, whether they be yearly or cyclical.[62]

60 Environmental Information Summaries, C-14, HDD and CDD Day Data, NOAA, Department of Commerce, USA.

61 Hearing Transcript, Vol. VI, pages 192-193.

62 Case No. 8616, final Order dated March 2, 1983, page 13.

LG&E's use of NOAA's published 1951-80 degree day data[63] as a "current" 30-year average ignores the impact that any recent temperatures may have had in defining normal degree days. The Commission is concerned that it may bias that information which is being considered as the standard for temperature normality.

In Exhibit 2 of his direct testimony, Mr. Ryan constructed 95 percent confidence intervals around the NOAA 1951-1980 30-year means. He asserts that since the annual total degree days and most of the monthly degree days fall outside of the confidence interval, the entire test year must be normalized for abnormal weather. In LG&E's effort to demonstrate that test year weather was abnormal, Mr. Ryan stated:

> Q. Since temperature is a random variable, can't you employ a statistical procedure to determine whether or not actual temperatures were statistically different from the historical average?
>
> A. Yes. This basically would involve the construction of a confidence interval around the mean of the weather variable. If the number of degree days actually incurred during the test period falls outside the confidence interval limits, they can be considered statistically different from the average.[64]

Though LG&E has used a confidence interval as a standard for testing normality, LG&E did not use the confidence interval for temperature adjustment purposes. Mr. Ryan adjusted each month's actual billing cycle temperature-sensitive load to a mean-determined temperature-sensitive load instead of to a

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63 Climatography of the United States No. 81 (By State), Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1951-80, Kentucky.

64 Ryan Prepared Testimony, page 6.

temperature-sensitive load determined by the boundaries of a range of acceptable values constructed around the mean.

The Commission is of the opinion that there is adequate evidence to suggest that a range of temperatures and not a specific mean temperature is a more appropriate measure of normal temperatures. As long as the temperature falls within these bounds then it is inappropriate to adjust sales for temperature. However, if the temperature falls outside those bounds then it is appropriate to adjust sales to the nearest bound.

After determining normal weather and the departure of test year weather from normal, the methodology proposed by LG&E to determine weather-normalized sales involves estimating two components of total energy usage: baseload and temperature-sensitive load. LG&E's actual calculation of the weather normalization adjustment begins by determining the number of customers in each class for each month of the test year, as well as billing cycle days and billing-cycle degree days for each month of the test year. Billing cycle days were defined by Mr. Ryan to be the average number of days in all of LG&E's 21 billing districts for each month during the test year. Billing-cycle degree days were then defined to be the average number of degree days in each billing period for each month.

The Commission is concerned with the calculations of both billing cycle days and billing-cycle degree days. Mr. Ryan indicated on cross-examination that other LG&E personnel were specifically responsible for the calculations[65] and that these calculations assume an average and are not tied to the beginning and ending dates of district billing cycles.[66] This method of determining billing-cycle degree day fails to properly match customer load and their corresponding bills, because each billing cycle has discrete beginning and ending dates with specific degree days and customers associated with that period. Additionally, since no attempt was made to weight the billing-cycle degree days by the percentage of total customers included within each billing district, the results using billing-cycle degree days are not representative of the temperature's affect on electricity usage across billing districts unless each cycle includes approximately the same number of customers per class, an assumption which cannot be confirmed by LG&E.[67] Due to these problems and the lack of supporting evidence, the Commission finds that the method used to convert calendar month days and degree days into billing cycle days and degree days is inaccurate.

The accuracy of the billing cycle calculations is critical because these results are used in the calculation of the final temperature adjustment. Inaccuracies contained in LG&E's billing cycle calculations, therefore, render LG&E's entire electric temperature normalization adjustment unreliable and unacceptable.

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65 Hearing Transcript, Volume V, page 14.

66 Ibid., page 145.

67 Hearing Transcript, Volume V, pages 146-147.

As previously stated, LG&E separated total mWh sales into only two components: baseload and temperature-sensitive load. Residential baseload has been derived from the company's load research data. LG&E determined the daily residential baseload per customer based on the average of the 5 lowest days of daily energy usage from a selected sample of load research customers. For the test year this was determined to be 16.6 KWH per residential customer per day. To determine monthly total residential baseload, the 16.6 was then multiplied by the number of customers in each test year month. This product was then multiplied by monthly-billing cycle days. For the commercial sector, a weighted-average baseload was determined, which includes weekend and weekday usages.

The actual temperature-sensitive load was calculated by simply subtracting the actual estimated baseload per customer from the actual total load per customer. The number of actual billing-cycle degree days was then divided into the actual temperature-sensitive load to obtain the actual energy use per customer, per degree day. Normal temperature-sensitive load was then determined by multiplying the actual energy use per customer, per degree day times the number of customers times the normal number of billing-cycle degree days in that month. This normal temperature-sensitive load was then subtracted from actual temperature-sensitive load to determine the mWh sales adjustment.

Further, LG&E, in adopting its adjustment methodology, has failed to follow previous Commission orders to consider other variables in addition to temperature when normalizing sales. The methodology chosen by LG&E neglects to consider other factors (i.e., personal income, employment, humidity, wind, etc.) that may affect test-year electricity usage. LG&E has recognized that other factors may affect electricity sales but has not incorporated any of these factors in this adjustment.[68] By ignoring these variables LG&E's methodology does not accurately determine the actual relationship of electricity sales to degree days.

In his testimony, Mr. Ryan acknowledges the strong relationship between electricity usage and degree days,[69] as determined by a simple econometric model. Further, Mr. Ryan states that LG&E "is fully aware that variables other than weather affect electricity usage."[70]

The econometric modeling of temperature normalization is widely used by both the electric utility industry and regulatory agencies. During cross-examination, Dr. Carl Weaver, witness for the AG, recommended that to determine temperature-sensitive load, ". . . you should use a regression analysis but include more than one independent variable . . ."[71] Mr. Ryan admitted on cross-examination that to verify that relationships between loads and degree days existed on a class basis, regression analysis would be required.[72] However for the purpose of verifying these

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68 Ibid., Volume V, page 92.

69 Ryan Prepared Testimony, Exhibit 5.

70 Ibid., page 15.

71 Hearing Transcript, Vol. X, page 34.

72 Ibid., Vol. V, page 140.

relationships, Mr. Ryan has ignored those statistical techniques and instead relied upon "eyeballing" the temperature-sensitive load figures.[73] The primary use of an econometric or regression model in weather normalization is to adjust test year sales, which is the intended purpose of a weather normalization adjustment. During cross-examination, Mr. Ryan stated that there was no question in his mind regarding the accuracy of the relationship between degree days and KWH sales because he has been working with weather data and has made the type of computer runs that support the relationship. However, he further stated that the Commission has not seen those computer runs and that other than his assertion that loads per degree day look reasonable, nothing has been filed in the record of this case which verifies the accuracy of that relationship.[74] The Commission cannot allow an adjustment of over $7 million on such a nonspecific basis. In any case, if LG&E desires to propose an electric temperature adjustment in future rate applications, it should develop a methodology that will accurately and appropriately match the random effects of weather to electricity consumption. Further, LG&E should provide adequate support to verify the accuracy and appropriateness of any model presented. The Commission will require that LG&E provide documentation, including adequate statistical analysis, sufficient to support the accuracy of the relationships in the methodology developed and submitted in subsequent rate cases.

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73 Ibid., pages 141-142.

74 Ibid.

Stephen J. Baron of Kennedy and Associates proposed an alternative electric weather normalization adjustment on behalf of KIUC. In discussing the adjustment proposed by LG&E, Mr. Baron criticized several aspects of LG&E's model and concluded that LG&E's methodology was ". . . not precise and cannot be verified as to whether it is correct using actual monthly data."[75] Mr. Baron further stated that he believed that the most appropriate method to develop class weather normalization adjustments was by developing regression models utilizing load research data. No such analysis was presented in this case and Mr. Baron, therefore, determined that using the aggregate system sales and weather data supporting Ryan Exhibit 5 to develop system-wide sensitivity coefficients was the most appropriate way to correct LG&E's proposed adjustment. Mr. Baron then used these system-wide coefficients to adjust LG&E's class-by-class sales, revenue and expense adjustments.

Mr. Baron has recognized several important flaws in LG&E's methodology and attempts to correct these in order to calculate a more representative electric weather normalization adjustment. Mr. Baron's proposed adjustment, however, does not correct the problems presented by LG&E's methodology. By using the system company-wide data supporting Ryan Exhibit 5 (which represents a test year which has been characterized as abnormal) and then interpreting these into class-by-class adjustments, Mr. Baron has

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75 Baron Prepared Testimony, filed February 16, 1988, page 14.

incorporated in his model the same inaccuracies and problems he noted in LG&E's model.

The Commission, therefore, finds that LG&E's proposed electric temperature adjustment should be denied for the following reasons:

1. LG&E's definition of normal degree days is based on 30-year data for the period 1951-1980, which does not include data for the most recent 7 years, including the test year.

2. The critical billing cycle calculations are inaccurate and do not reflect the actual degree days on either an actual or historic basis.

3. LG&E adjusted to a mean rather than to a range determined by a confidence interval.

4. LG&E has recognized only one variable that affects consumption.

5. LG&E did not accurately determine the relationship of KWH sales to degree days. LG&E simply estimated baseload and assigned the difference between total KWH sales and baseload to temperature-sensitive load.

6. LG&E has neither supported all of the assumptions nor supported the accuracy of its model.

The Commission is of the opinion that the electric weather normalization adjustment proposed by KIUC should be denied. The Commission cautions that alternative adjustments that suffer from the same inadequacies as the adjustments they are meant to replace are unacceptable.

Labor and Labor-Related Costs

LG&E proposed adjustments to increase the test-year operating expenses by $5,389,668 for labor and labor-related costs. The actual cost items and the proposed adjustments to combined gas and electric operations are as follows:

	Total
Wages and Salaries	$3,132,927
Pension Costs	34,698
Health Insurance	1,224,561
Dental Insurance	47,280
Group Life Insurance	148,914
Thrift Savings Plan	248,469
FICA Taxes	550,126
Unemployment Taxes:	
State	30,421
Federal	<26,728>
TOTAL	$5,390,668

Excluding the gas supply expense adjustment, the adjustment for labor and labor-related costs represents the largest adjustment to LG&E test-year operating expenses. In this case, as has been previously stated, the labor and labor-related costs are areas of concern for two reasons: the notice in Case No. 8924 that the Commission would analyze health insurance costs in LG&E's next rate case and the recommendations incorporated in the Management Audit regarding fringe benefits and work force considerations.

Wages and Salaries

LG&E proposed to increase wages and salaries by $3,132,927 in order to reflect wage increases granted during and subsequent to the test year. The first part of this adjustment reflects an increase of $784,852 to recognize the increases granted during the test year. The second part represents the increases granted in

October and November 1987, which results in an increase of $2,348,075. Generally, when utilities request adjustments to wages and salaries, a comparison is made between actual test year wages and salaries and a normalized or pro forma expense level. In this and recent proceedings, LG&E has not determined the adjustment to wages and salaries by the methodology described above. Mr. Fowler testified that LG&E did not follow this methodology because LG&E's test-year labor costs include overtime, shift differentials and other items.[76] Mr. Fowler further stated that LG&E was trying to compare wages on a straight-time basis, that overtime was not included in the adjustment and that the adjustment was very conservative.[77]

Mr. Kollen, on behalf of KIUC, agreed with the first part of the wage adjustment but recommended that the second part be denied in that it represents increases granted outside the test year.

LG&E's wages and salaries consist of various components including overtime pay, shift pay, and straight-time labor. Since LG&E has adjusted only the straight-time component, the Commission does agree that the adjustment is conservative. The Commission also recognizes that the second part of the proposed adjustment is based upon increases granted subsequent to the test period. However, the Commission has, in some circumstances, allowed adjustments of this nature for various reasons. Allowing this adjustment will provide a more accurate matching of wage expense to the

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76 Hearing Transcript, Vol. III, page 130.

77 Ibid.

future rates which are intended to recover those wages. Additionally, the Commission notes that in Case No. 8616, which used a test year ended June 30, 1982, the Commission allowed LG&E to pass on wage increases granted in October and November 1982.[78] Therefore, the Commission is of the opinion that the full amount of the proposed adjustment to wages and salaries should be accepted.

Even though LG&E has adjusted only one component of wages and salaries, the Commission is concerned with LG&E's inability to provide the actual test year expense for each component of wages and salaries inasmuch as such information is necessary to accurately determine an adjustment to wages and salaries. During cross-examination, Mr. Fowler indicated that LG&E does not completely maintain the payroll records by employee classes[79] and in response to Commission data requests stated that,

> The automated payroll file by employee category is constantly changing as employees are added, deleted or transferred between categories and the data for prior periods is not retained. Thus, the annualized straight-time salaries of employees by categories can be determined for current employees, but such a calculation cannot be made for prior periods.[80]

LG&E is encouraged to incorporate the ability to determine the separate components of wages and salaries in the Management Information Systems being developed. The Commission, in future LG&E rate cases, will review the adjustments proposed for wages and

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78 Case No. 8616, final Order dated March 2, 1983, page 23.

79 Hearing Transcript, Vol. III, page 131.

80 Response to the Commission Order dated January 15, 1988, Item No. 8.

salaries while considering the actual test year-end levels of each element.

Group Life Insurance

LG&E proposed an adjustment of $148,914 to increase test-year operating expenses as a result of changes in the premium allowance for nonunion employees and to reflect the increased life insurance premiums resulting from the labor increase allowed in this case. In response to Item No. 16(d), page 10 of the Commission's Order dated November 12, 1987, LG&E provided the calculations to normalize the union and nonunion portions of this adjustment. The insurance benefit is equal to 125 percent of annual salary and the rate per $1,000 of insurance is $.59 for both categories of employees. For all employees, LG&E pays 100 percent of the premium on the first $5,000 of insurance. Prior to April 1, 1987, LG&E paid 75 percent of the premium for insurance in excess of the first $5,000 for all employees; however, on that date, LG&E, in accordance with the nonunion employees' benefit improvement package, began paying, for nonunion employees, 100 percent of the premium in excess of the first $5,000.

The adjustment proposed by LG&E reflects the change instituted in April for the nonunion employees; however, for simplicity, the calculation for union employees does not reflect the fact that LG&E pays 100 percent of the first $5,000 of insurance.[81] The Commission is of the opinion that the Group Life Insurance adjustment should be modified as determined in Appendix

[81] Response to the Commission Order dated December 23, 1987, Item No. 21, page 1.

B to this Order and as discussed below. The union employees' portion of the adjustment is calculated in a manner which does reflect that LG&E pays 100 percent of the premium for the first $5,000 of insurance and 75 percent of the amount over the first $5,000. Additionally, as previously discussed in the preceding Management Audit section of this Order, the nonunion employee portion has been calculated in the same manner as the union employees in order to recognize LG&E's benefit level prior to April 1, 1987. These changes result in a reduction of $40,534 to LG&E's proposed $148,914 adjustment. The Commission will, therefore, allow an increase in test-year operating expenses of $108,380 to reflect the increased costs associated with group life insurance.

Unemployment Taxes

LG&E proposed an adjustment to increase the expenses associated with federal and state unemployment taxes by $3,693. In his direct testimony, Mr. Fowler indicated that the adjustment resulted because of a higher wage base subject to these taxes; however, the decrease in the federal unemployment tax rate offset the increased wage rate and resulted in a negative adjustment for federal unemployment taxes.[82] As shown in Item No. 69(d)(1), the proposed adjustment relating to state unemployment taxes increases expenses by $30,421, while the adjustment related to federal unemployment taxes resulted in a decrease of $26,728.[83]

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82 Fowler Prepared Testimony, page 10.

83 Response to the Commission Order dated November 12, 1987.

In determining the amount of the adjustment, LG&E multiplied the base wage subject to unemployment tax by the total employees as of September 22, 1987 and multiplied this product by the applicable tax rate. LG&E provided the total number of employees at the end of several payroll periods in response to a Commission Information Request.[84] In that response, LG&E indicated that there were 3,920 employees as of September 6, 1987, which is the payroll period nearest the end of the test period. During cross-examination, Mr. Fowler indicated that the level of employees used in the adjustment was based on the September 22, 1987 payroll period because that was the approximate date the calculation was performed.[85] Additionally, Mr. Fowler stated that this calculation utilized a 0.6 percent federal unemployment tax rate in anticipation of a proposed change in that rate. Ultimately the change was not effected, thereby leaving the tax rate at 0.8 percent.

The Commission is of the opinion that it is more appropriate to use the number of employees in the payroll period nearest the end of the test year and the federal tax rate actually in effect in the calculation of this adjustment. Therefore, the Commission has, in Appendix C, recalculated this adjustment using 3,920 as the base number of employees and 0.8 as the federal unemployment tax rate. This recalculation results in increases to the test-year federal and state unemployment tax expense of $8,914 and

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84 Ibid., dated January 15, 1988, Item No. 14(c).

85 Hearing Transcript, Vol. III, page 136.

$21,573, respectively. The net effect is an increase to test-year operating expense of $30,487.

Thrift Savings Plan

LG&E proposed an adjustment to increase the test-year operating expense by $248,469 to reflect the normalized expense associated with the thrift savings plan instituted April 1, 1987 in the nonunion employee benefit improvement package. As previously discussed in the Management Audit section, the Commission has disallowed the expenses associated with this item. Therefore, the Commission has reduced operating expense by $180,668 which represents the actual test year expense associated with the thrift savings plan.

Health Insurance

LG&E proposed an adjustment of $1,224,561 to increase the test year level of health insurance expense. Testimony regarding this adjustment was presented by Mr. Hancock. Mr. Hancock also addressed the measures taken by LG&E to control medical benefit costs in response to the final Order in Case No. 8924.

As noted previously in the Management Audit section of this Order, the Commission will allow the proposed increase relating to the expense for the actual health insurance plans, but will not allow LG&E to include the expense relating to the cash incentive payments. According to Item No. 16(d), page 8,[86] the actual test year expense for health insurance was $7,781,922. This amount included $196,408 relating to the cash incentive payments. The

[86] Response to the Commission Order, dated November 12, 1987.

remaining $7,585,514 was subtracted from the pro forma operating expense relating to the actual insurance plans of $8,810,075 to arrive at the proposed adjustment of $1,224,561. The Commission, after reflecting the $196,408 decrease associated with the cash incentive payments, has increased the test-year operating expenses by $1,028,153 to recognize the increased health insurance costs.

Adjustment to Annualize Year-End Electric Volumes of Business

John Hart, Vice-President of Rates and Economic Research for LG&E, proposed an adjustment to reflect the increased costs associated with serving the level of customers at the end of the test year. The proposed adjustment, as amended by Mr. Hart, increased test-year operating revenues by $3,531,357 and test-year operating expenses by $1,860,852. The net effect is a proposed increase in test-year operating income of $1,675,005.

To determine the adjustment to operating revenue, the excess of customers served at test year-end over the test-year average customers was multiplied by an average revenue per customer. The average revenue per customer was determined using the actual revenues from sales to ultimate consumers adjusted to reflect the present rates for a full year, the transfers between rate schedules and normal temperatures. The Commission has previously determined that the proposed electric temperature normalization adjustment should be denied. Therefore, the proposed adjustment to electric operating revenues has been increased to $3,627,565 as calculated by the Commission to reflect the disallowance of the adjustment for normal temperature.

To determine the adjustment to operating expenses, Mr. Hart calculated a cost per KWH of electricity and multiplied that cost by the excess of test year-end customers over test-year average customers. As Mr. Hart explained during cross-examination, this is a traditional calculation made by LG&E[87] which has previously been accepted by the Commission. In performing the calculation in this manner, LG&E has treated all operation and maintenance expenses as variable costs, costs that will increase proportionately with each additional KWH sold. LG&E has not provided conclusive evidence that this is an accurate relationship of all operating expenses to KWH sales. As Mr. Hart admitted during cross-examination, customer accounting expenses, customer service and information expenses, and some portion of administrative and general expenses would vary with the number of customers and not with KWH sales.[88] In response to an information request, LG&E stated that an argument could be made for calculating the expense adjustment based on the company's operating ratio.[89] During cross-examination, Mr. Hart indicated that this approach was not used because he was being conservative in his approach and that his approach had been used for a number of years by LG&E.[90]

The Commission is of the opinion that the approach used by LG&E does not provide an accurate determination of the increase in

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87 Hearing Transcript, Vol. I, page 194.

88 Ibid., Vol. VI, pages 194-195.

89 Response to the Commission Order dated January 15, 1988, Item No. 24.

90 Hearing Transcript, Vol. VI, page 200.

the level of expenses associated with serving additional customers and that it would be more appropriate to use an adjusted operating ratio. The Commission has accepted similar methods to adjust expenses to reflect year-end customers for other companies under its jurisdiction. An appropriate ratio of expenses to sales for use in this case should be 39.84 percent. The calculation of this ratio and the expense adjustment is included in Appendix D of this Order. In determining this ratio, actual test year wages and salaries have been subtracted from actual test year operation and maintenance expenses. It is not appropriate to include wages and salaries in this calculation because the amount of those costs to be included in future rates has previously been adjusted and reflects test year-end employees and post-test-year wage rates. Additionally, the amount of sales to other utilities, which is a net amount, has been deducted from total actual electric operating revenues.

The Commission is of the opinion that this method more accurately reflects the relationship of expenses to sales than the approach used by LG&E. Therefore, the Commission finds that the adjustment to LG&E's electric operating and maintenance expenses should be an increase of $1,445,222. The net effect of this adjustment is a decrease to test-year operating expenses of $2,182,343 or $507,338 above the net amount proposed by LG&E. The Commission advises LG&E that this issue will be considered in future rate proceedings.

Provision for Uncollectible Accounts

LG&E proposed an increase of $250,000 to the test year provision for uncollectible accounts based on its analysis of the appropriate total annual provision. The total provision and the increase were allocated between electric and gas based on the percentage of gross revenues from ultimate consumers for the preceding calendar year. While the Commission finds the proposed increase acceptable, it is concerned about LG&E's use of an allocation method based on revenues instead of actual electric or gas uncollectible account charge-off history. The amounts recorded for electric and gas provisions for uncollectible accounts were not based on the history of uncollectible charge-offs because LG&E did not maintain records of charge-offs by department.[91] LG&E should develop and maintain a record of actual uncollectible charge-offs by department and should utilize that information in adjusting the provision for uncollectible accounts in future rate proceedings.

Depreciation Expense

LG&E proposed to increase depreciation expense by $2,408,809 in order to annualize the test year expense. Of the total adjustment, $2,197,774 was for electric and $211,035 was for gas. Included in the gas depreciation calculations was the depreciation expense for gas underground storage property. The depreciation for this portion of the gas plant was computed using a rate of 5.05 percent. As has been discussed in the section of this Order

91 Response to the Commission Order dated December 23, 1987, Item No. 40.

relating to retirements of SDRS and gas plant, LG&E revised its depreciation rates for gas underground storage property in order to recover the losses incurred when it abandoned three underground storage fields.[92] If LG&E had computed annual depreciation expense using a rate of 3.37 percent, which was in use before the abandonment, there would be a reduction of $536,972 in gas plant depreciation.[93] Because the Commission has decided to treat the abandonment loss as extraordinary, the use of the higher depreciation rate is unnecessary. The Commission has reduced the test-year depreciation expense for the gas plant by $325,937 to reflect the rate of 3.37 percent on gas storage plant. The Commission has accepted the electric depreciation adjustment. Therefore, the total increase to depreciation expense allowed herein is $1,871,837.

Advertising Expense

LG&E proposed to remove $267,278 from its test-year advertising expenses, which represented expenditures which were not allowable for rate-making pursuant to 807 KAR 5:016. The prohibited advertising expenses include promotional, political, and institutional advertising. At the hearing, LG&E witness, Mr. Wilkerson, introduced a schedule of promotional advertising expenses which had not been included in LG&E's original

92 Hearing Transcript, Vol. IV, page 21.

93 Response to KIUC Second Data Request, filed February 1, 1988, Item No. 16.

adjustment, and indicated these expenses should also be removed.[94] The additional promotional advertising expenses totaled $52,960. The Commission has accepted both of the advertising adjustments proposed by LG&E, and has reduced advertising expenses by a total of $320,238. The $267,278 in reductions to the electric and gas operations are accepted as proposed; in addition, the $52,960 has been allocated, $40,779 to electric and $12,181 to gas, based on LG&E's reported allocation methods for such costs.

Membership Dues

During the test year, LG&E paid membership dues to the Edison Electric Institute ("EEI") of $164,390 and to the Coalition for Environmental Energy Balance ("CEEB") of $5,800. In addition, LG&E paid $20,760 to EEI as its annual assessment for an acid precipitation study. LG&E included these expenditures in adjusted test-year operating costs.

LG&E was asked to enumerate the benefits of EEI membership and provide any cost-benefit analysis performed concerning membership. LG&E was also asked to provide a breakdown of the EEI dues based on EEI activities. In its responses, LG&E indicated it had not and could not perform cost-benefit analysis of its membership.[95] While providing a listing of benefits, the listing was general in nature and did not document any specific benefits

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94 Hearing Transcript, Vol. VIII, pages 185-191 and Wilkerson Exhibit 1.

95 Response to the Commission Order dated December 23, 1987, Item No. 36(d), page 2 of 7.

received by LG&E's ratepayers.[96] LG&E was asked to describe the nature of CEEB and why it was a member. LG&E provided a general description of the activities of CEEB and explained that the CEEB activities were compatible with LG&E's mission.[97] However, LG&E's responses did not indicate any direct benefits to its ratepayers from CEEB membership.

The Commission is aware that the payment of membership dues to organizations such as EEI and CEEB have received differing regulatory treatment across the country in recent years. The Commission takes notice of two recent cases which involved situations similar to the one the Commission faces in this case. In a case before the Missouri Public Service Commission, EEI dues were disallowed in their entirety because there was no way to quantify the benefits accorded ratepayers and shareholders from membership in the association.[98] In a case before the Massachusetts Department of Public Utilities, the assertion that EEI membership provided numerous and substantial benefits to electric ratepayers did not relieve a utility of its duty to prove that the dues represented a reasonable operating expense and the dues were disallowed.[99]

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96 Ibid., Item No. 36(c), pages 1 and 2 of 7.

97 Response to CAG First Data Request, filed February 8, 1988, Item No. 15.

98 Arkansas Power and Light Company, 74 PUR4th 36 (1986), Case Reference ER-85-265.

99 Western Massachusetts Electric Company, 80 PUR4th 479 (1986), Case Reference DPU 85-270.

In this case, LG&E has failed to show that its membership in EEI and CEEB is of direct benefit to its ratepayers. Therefore, the Commission has excluded all EEI and CEEB costs in the amount of $170,190 from allowable operating expenses for rate-making. This issue will be reconsidered in future cases if LG&E can document that the costs of membership dues provide a direct benefit to the ratepayers.

The Commission recognizes the growing concern in this country over the problems of acid rain. Studies, such as the one being performed by EEI, could provide valuable information in the resolution of this problem. The Commission finds that the EEI acid precipitation study could provide future benefits to LG&E and its ratepayers. Therefore, the Commission has included the $20,760 annual assessment as an allowable rate-making expense.

Excess Deferred Taxes - Tax Reform Act of 1986

In Case No. 9781, The Effects of the Federal Tax Reform Act of 1986 on the Rates of Louisville Gas and Electric Company, Order dated June 11, 1987, the Commission explored the issue of excess deferred taxes resulting from the change in tax rates under the Tax Reform Act. The Commission stated that the accelerated amortization of the unprotected excess deferred taxes would be considered in future rate proceedings.[100] In response to a data request LG&E provided the amount of unprotected excess deferred taxes available for accelerated amortization.[101] In addition, LG&E

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[100] Case No. 9781, final Order dated June 11, 1987, page 10.

[101] Response to the Commission Order dated December 23, 1987, Item No. 30.

provided a calculation of a deferred tax deficiency arising from an increase in the state corporate tax rate. LG&E took the position that the federal excess deferred taxes should be offset by the state deficiency in accordance with the Commission Order in Case No. 8616.[102] Mr. Kollen, on behalf of KIUC, has recommended that the unprotected excess deferred taxes as of August 31, 1987 be offset by the same proportion of the state tax deficiency and be returned to the ratepayers as a 1-year credit to base rates.[103] At the hearing, LG&E indicated that the original information filed could violate the normalization requirements of the Tax Reform Act and subsequently filed an amended calculation.

The Commission is of the opinion that the unprotected excess deferred taxes of $4,749,500 as of August 31, 1987,[104] the test year-end, should be offset by the full state tax deficiency of $4,385,600 and amortized over 5 years for rate-making purposes. The effect of this decision is an annual reduction in income tax expense in the amount of $72,780. This amount has been allocated to gas and electric operations in proportion to the existing deferred tax reserve after the adjustment for early retirements with $6,703 allocated to gas operations and $66,077 to electric operations. The rate base has been increased by a like amount to recognize the first year's amortization. LG&E should transfer the excess and deficiency to separate accounts in order that they can

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102 Ibid.

103 KIUC Brief, May 9, 1988, pages 30-33.

104 Response to Hearing Data Request, filed May 9, 1988, Excess Deferred Federal Income Taxes as of December 31, 1987.

be readily identified in future rate proceedings. The Commission is of the opinion that this method is in keeping with the position established in Case No. 8616[105] and does not represent a change of Commission practice.

Management Audit Adjustments

LG&E proposed an adjustment to reflect the recovery of the cost of the Management Audit over a 3-year period. The effect of this adjustment is to increase operating expenses by $194,000. The proposed adjustment allocates $44,620 to gas operations and $149,380 to electric operations. Pursuant to KRS 278.255, the agreement between LG&E, RM&A/Scott and the Commission stated that the cost of the audit would be an allowable expense for rate-making purposes. The Commission, therefore, has accepted the adjustment as proposed by LG&E.

The $2,475,092 test-year cost of the management information systems discussed in the Management Audit section of this Order has been allocated by the Commission to gas and electric and operations in the same proportion as the cost of the Management Audit. The adjustments decrease the test-year operating expenses in the gas department by $569,271 and by $1,905,821 in the electric department.

As previously discussed in the Management Audit section, the Commission has disallowed $258,040 associated with the test-year cost of open management audit recommendations. The test-year cost of $1,477,900 of these recommendations was detailed by LG&E in

[105] Case No. 8616, final Order dated March 2, 1983, pages 20-21.

response to a data request.[106] Commission review of this response indicates that $1,166,900 of these costs have been capitalized or included in the disallowed cost of the management information systems. An additional $52,960 was included by Mr. Wilkerson at the hearing as additional disallowed advertising and has been included in that adjustment, as amended. The remaining $258,040 is based on the following recommendations as detailed in the response to a data request and has been allocated to gas and electric operations as indicated below:[107]

Recommendation	Gas	Electric	Total
V-5	$11,969	$ 40,071	$ 52,040
XI-3	3,220	10,780	14,000
XIV-1	-0-	12,000	12,000
XVI-1, 2, 3	53,000	-0-	53,000
XVIII-1, 2, 3, 5	29,210	97,790	127,000
TOTAL	$97,399	$160,641	$258,040

Recommendations XIV-1 and XVI-1, 2, and 3 have been identified as specific to either gas or electric operations. The other recommendations were allocated to gas and electric operations in the same manner as the cost of the Management Audit.

The total effect of these adjustments is to decrease operating expenses by $2,539,132. The decrease in gas operations is $622,050 and in electric operations is $1,917,082.

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106 Response to the Commission Order dated January 15, 1988, Item No. 1.

107 Ibid.

Storm Damage Expenses

LG&E has proposed an adjustment to amortize, over a 3-year period, unrepresentative storm damage expenses incurred during July 1987. This proposed adjustment would decrease test year operations and maintenance expenses by $976,896.

Listed below are actual storm damage expenses for the past 5 calendar years as indicated by LG&E:[108]

Year	Amount
1982	$ 442,375
1983	448,465
1984	332,705
1985	1,670,904
1986	722,355

The actual test-year storm damage expenses were $3,189,909, an amount greater than in any 3 of the past 5 calendar years. After the proposed adjustment is reflected, the test year would still include $2,213,013 in storm damage expenses.

Mr. Fowler of LG&E stated at the hearing that over a 2-week period LG&E's service area was hit by a series of very extensive and unusual storms.[109] Mr. Fowler indicated in his prepared testimony that the company considers these expenses to be legitimate, reimbursable costs.[110] However, LG&E recognized that the recovery of costs of this magnitude might overstate the level of expenses during a normal 12-month period and has, therefore,

108 Response to the Commission Order dated December 23, 1987, Item No. 25(e).

109 Hearing Transcript, Vol. III, page 116.

110 Fowler Prepared Testimony, page 12.

proposed an adjustment to amortize these costs over a 3-year period.[111]

During redirect examination, Mr. Fowler stated:

> If the Commission takes the position that you cannot recover these costs, we can certainly reduce these costs very easily by allowing the customer to stay off five weeks instead of two weeks or one week, by doing the repairs during normal business hours with our regular employees.[112]

Mr. Fowler further stated during recross-examination that he believed that LG&E should make every effort to restore service but should the Commission exclude costs incurred for the benefit of the customer, there is a point beyond which the company would have to consider the extent of its efforts. He further stated that if ". . . the stockholders are going to have to eat the expenses, there would become a point where maybe a day or two delay would not seem unreasonable."[113]

In determining a reasonable level of operating expenses and an appropriate rate of return, the Commission considers both the risks of the shareholders and the appropriate cost of service to be borne by a utility's ratepayers. In the present case, LG&E argues that the expenses were incurred for the benefit of the ratepayers. However, the stockholders were unable to earn a return until service had been restored. Clearly, expeditious restoration of service is of benefit to both ratepayers and stockholders.

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111 Ibid.

112 Hearing Transcript, Vol. IV, page 54.

113 Ibid., pages 145-146.

The random occurrence of severe storm damage cannot be accurately predicted. This can be seen from the historical calendar year experience noted above. LG&E has focused on only 1 month of the test year in determining that the $1,465,344 abnormal expense incurred in July should be amortized. Mr. Fowler indicated during cross-examination that the 1985 storm damage expense of $1,670,904 was abnormal.[114] Yet, he proposed to include $1,724,565 as an on-going or normal level of storm damage expenses in addition to the amortization of the abnormal July expense of $488,448. The Commission is of the opinion that the test year should include only a reasonable level of storm damage expenses. The proposed adjustment does not render the test period expense representative for rate-making purposes, but projects a level of expense that is clearly abnormal in relation to the historical storm damage expense as indicated by LG&E. The Commission has, on past occasions, determined a reasonable level of expenses by utilizing a historical average and reaffirms that policy. In this case, the average of the test year and the 4 previous calendar years results in an allowable average of $1,272,868 and a decrease in test year expenses of $1,917,041. The Commission finds that this does not deny recovery but merely establishes a reasonable level of expense for the period in which rates will be in effect. In addition, LG&E should continue to make every effort to restore service as soon as possible.

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[114] Ibid., Vol. III, pages 121-123.

Interest Synchronization

The Commission has applied the cost rates applicable to the long-term debt and short-term debt components of the capital structure in order to compute an interest adjustment. The debt components utilized in this computation reflect the effects of the JDIC allocation and reductions to capital structure due to the extraordinary property losses discussed in this Order. Using the adjusted capital structure allowed herein, the Commission has computed an interest adjustment of $122,093 which results in a reduction to income taxes of $47,353.

After applying the combined state and federal income tax rate of 38.785 percent to the accepted pro forma adjustments, the Commission finds that combined operating income should be increased by $25,109 to $118,883,427.

The adjusted net operating income is as follows.

	Gas	Electric	Total
Operating Revenues	$52,020,765	$460,363,195	$512,383,960
Operating Expenses	44,532,659	348,967,874	393,500,533
ADJUSTED NET OPERATING INCOME	$ 7,488,106	$111,395,321	$118,883,427

RATE OF RETURN

Capital Structure

Mr. Fowler proposed an adjusted end-of-test-year capital structure containing 46.17 percent debt, 9.40 percent preferred stock, and 44.43 percent which reflect the adjustments discussed in the Capital section of this Order.

Dr. Weaver, witness for the AG, proposed a capital structure containing 46.20 percent debt, 9.47 percent preferred stocks, and 44.33 percent common equity. As stated in the Capital section of this Order, the difference between Dr. Weaver's proposed capital structure and Mr. Fowler's was the result of the date used by Dr. Weaver in determining capital structure and in the adjustments to reflect discounts on preferred stock and common equity.[115]

Mr. Kollen, witness for KIUC, proposed a capital structure containing 48.55 percent debt, 9.89 percent preferred stock and 41.56 percent common equity based on his proposed adjusted capital.

The Commission has determined LG&E's adjusted capital structure for rate-making purposes to be as follows:

	Amount	Percent
Debt	$ 614,484,032	46.17
Preferred Stock	125,170,510	9.40
Common Equity	591,346,711	44.43
	$1,331,001,253	100.00

In determining the capital structure, the Commission has accepted the adjustments to capital proposed by LG&E and has used the capital ratios reflected as of September 1, 1987. As previously stated, the test-year-end JDIC has been allocated to each component of the capital on the basis of the ratio of each component to total capital, excluding JDIC, as proposed by LG&E and in accordance with past Commission treatment of this item. In

115 Weaver Prepared Testimony, pages 35-36.

addition, the total capital has been reduced by $19,571,002 to reflect the extraordinary property losses, which are explained in another section of this Order. The losses have been allocated on the basis of the ratio of each capital component to the total capital.

Cost of Debt

Mr. Fowler proposed a cost of 8.09 percent for preferred stock which was based on the embedded rate as of August 31, 1987.[116] Dr. Weaver recommended an 8.02 percent rate for preferred stock. The difference between Mr. Fowler's and Dr. Weaver's proposed cost of preferred stock was that Dr. Weaver did not reduce the book value of the outstanding preferred stock by the issuing expense.[117] The Commission is of the opinion that issuance costs should be reflected in the cost of preferred stock. Therefore, the Commission is of the opinion that the reduction in book value of the outstanding preferred stock by the issuing expense is proper and that the 8.09 percent rate reflects the true costs of the preferred stock to LG&E.

Mr. Fowler further testified that LG&E's end-of-test year embedded cost of long-term debt was 7.62 percent and reflects adjustments for the retirement of $12,000,000 of First Mortgage Bonds, Series due September 1, 1987, a sinking fund requirement of $250,000 of 1975 Series A pollution control bonds, and the replacement of 1982 Series B (9.40 percent) pollution control

116 Fowler Prepared Testimony, page 17.

117 Weaver Prepared Testimony, page 36.

bonds with 1987 Series A (6.876 percent) bonds.[118] Dr. Weaver proposed a cost of debt of 7.51 percent which was based upon October 31, 1987 data.[119] The Commission is of the opinion that long-term cost of debt is 7.62 percent based on the end-of-test-year adjusted data.

Cost of Equity

Dr. Charles E. Olson, President of H. Zinder and Associates and witness for LG&E, recommended a return on equity in the range of 13.75 to 14.25 percent.[120] Dr. Olson's recommendation was based on a discounted cash flow ("DCF") analysis of LG&E. In addition, he utilized both a risk premium analysis and a DCF study of nine electric companies as a check on his estimate of LG&E's DCF cost of equity.

In the LG&E DCF analysis, Dr. Olson used (1) a dividend yield of 7.78 percent based on a dividend of $2.66 and a 6-month high/low average stock price of $34.188; and (2) an estimated dividend growth rate of 5.0 to 5.5 percent based on LG&E's 5-year earnings per share growth rate.[121] This resulted in an overall DCF estimate of 12.78 to 13.28 percent. Dr. Olson performed a risk premium analysis as his first check on his LG&E's DCF estimate. The "premium" that investors required over bond yields was estimated at 3.5 percent. This was higher than the 2.6 percent

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118 Fowler Prepared Testimony, Exhibit 5.

119 Weaver Prepared Testimony, page 37.

120 Olson Prepared Testimony, page 30.

121 Ibid., pages 17-22.

premium from Dr. Olson's source of information, a Paine Webber Mitchell Hutchins, Inc. publication titled "Electric Utility Industry - Electric Utility Analyst Survey" (April 19, 1985).[122] The 3.5 percent risk premium was added to LG&E's current bond yield of 10.1 percent resulting in a 13.6 percent required return. Dr. Olson's second check was based on a DCF analysis of nine electric utility companies and resulted in an average return on equity of 12.79 to 13.29 percent.[123] In addition, Dr. Olson increased his estimates by approximately 8.0 percent to allow for flotation costs and market pressure to arrive at his recommended range of 13.75 to 14.25 percent.[124]

Mr. Royer of LG&E recommended that a return on equity in the range of 13.8 to 14.8 percent is necessary to maintain the financial integrity of LG&E and to fund internal growth at 4.0 to 5.0 percent.

Dr. Weaver recommended a cost of equity in the range of 11.5 to 12.5 percent based on a DCF analysis and used the earnings/price ratio approach as a means to gain additional information. He applied the DCF model to LG&E and a group of four comparable companies using 1987 data and 1978-1980 historical data. Dr. Weaver developed his growth rates using the earnings retention ratio times return on equity (b x r) method. Dr. Weaver's results showed a cost of equity of 10.33 percent for the comparable

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122 Ibid., pages 25-26.

123 Ibid., page 28.

124 Ibid., page 29.

companies and 10.20 percent for LG&E in 1987, and a 13.58 percent and 11.58 percent for 1978-1980, respectively. Dr. Weaver's earnings/price ratio approach averaged 13.04 percent and were higher than his 1987 DCF results, but were closer to the 1978-1980 DCF estimates on the return on equity. Dr. Weaver recommended that no allowances be made for flotation costs or market pressure.

Dr. Jay B. Kennedy, a principal in Kennedy and Associates and witness for KIUC, recommended an 11.75 percent return on equity with a range of 11.34 to 12.21 percent. Dr. Kennedy's proposal was based on a DCF analysis on LG&E. He also performed a DCF analysis on a comparison group of five utilities and a risk premium analysis for verification. His ranges on return on equity were from the results of his DCF analysis and showed LG&E with an average 11.34 percent return on equity and the comparison group with an average 12.21 percent return on equity.[125] Dr. Kennedy's risk premium estimate was based on the difference between the comparison group's average bond yield of 10.02 percent for the July 1987 to December 1987 period, and the DCF cost of equity of 12.21 percent for the comparison group. This risk premium of 2.19 percent was then added to LG&E's long-term debt of 9.82 for a risk premium cost of equity of 12.01 percent.[126] Dr. Kennedy made no allowances for flotation costs or market pressure; however, he suggested that any future costs of issuing common stock be

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125 Kennedy Prepared Testimony, page 40.

126 Ibid., page 41.

measured and recovered externally as a cost of providing service, and levelized over a 30-year period at the weighted cost of capital.

Mr. Kinloch stated that LG&E's rate of return should be 12.0 percent assuming that LG&E no longer receives CWIP, but only 11.0 percent if they are allowed to continue receiving CWIP. Mr. Kinloch's recommendation was based on "current trends from around the nation on recent cases."[127]

The Commission has an obligation to allow LG&E an opportunity to earn a rate of return which will allow it to continue to maintain its financial integrity. In making its determination, the Commission finds that Dr. Olson has basically ignored his own data on growth estimates as provided in his testimony and, therefore, rejects his recommendation of a 14.0 percent return on equity in that it is in excess of an investor's required rate of return. In addition, the Commission also finds that Dr. Weaver's use of the b x r method, if earnings have been inadequate in the past, can understate the growth rate component and, thus, the investor's required return in the DCF analysis. The lower growth rate derived from the b x r method results in a lower allowed return which could result in lower earnings and a lower retention ratio and then a still lower growth rate component and so on. A downward trend could develop and thus weaken the financial integrity of LG&E. The Commission further finds that Dr. Kennedy's failure to give proper weight for the current volatile economic conditions

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127 Kinloch Prepared Testimony, page 13.

results in an understatement of the investor's required rate of return.

Therefore, the Commission having considered all of the evidence, including recent volatile economic conditions, is of the opinion that a return on equity in the range of 12.25 to 13.25 percent is fair, just, and reasonable. A return on equity in this range would allow LG&E to attract capital at a reasonable cost to insure continued service and provide for necessary expansion to meet future requirements, and also would result in the lowest possible cost to ratepayers. A return of 12.75 percent will best meet the above objectives.

Rate of Return Summary

Applying rates of 7.62 percent for debt, 8.09 percent for preferred stock, and 12.75 percent for common equity to the capital structure approved herein produces an overall cost of capital of 9.94 percent. The Commission finds this overall cost of capital to be fair, just, and reasonable.

REVENUE REQUIREMENTS

The Commission has determined that LG&E needs additional annual operating income of $13,463,256 to produce a rate of return of 12.75 percent on common equity based on the adjusted historical test year. After the provision for state and federal income taxes, there is an overall revenue deficiency of $21,993,394 which is the amount of additional revenue granted herein. The net operating income necessary to allow LG&E the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $132,346,693. A breakdown between gas and electric operations of the required operating income and the increase in revenue allowed herein is as follows.

	Total	Gas	Electric
Net Operating Income Found Reasonable	$132,346,683	$13,103,981	$119,242,702
Adjusted Net Operating Income	118,883,427	7,488,106	111,395,321
Net Operating Income Deficiency	13,463,256	5,615,875	7,847,381
Additional Revenue Required	21,993,394	9,174,017	12,819,377

The additional revenue granted herein will provide a rate of return on the net-original cost rate base of 9.98 percent and an overall return on total capitalization of 9.94 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $644,797,735. These operating revenues include $469,555,007 in electric revenues and $175,242,728 in gas revenues.

OTHER ISSUES

"Benchmark" Treatment of Operation and Maintenance Expenses

KIUC proposed a reduction of test-year operating and maintenance expenses totaling $25,771,000, which it claimed reflected the excessive expense growth above inflation and sales growth experienced by LG&E. The amount of reduction was determined utilizing a "benchmark" calculation presented by KIUC witness, Mr. Kollen. Mr. Kollen took the pro forma operation and maintenance expenses for the test year in LG&E's last general rate case and multiplied the amounts by an overall growth factor to arrive at a benchmark level of operation and maintenance expenses.[128] These figures were compared to the pro forma operation and maintenance expenses for the current test year, and the difference calculated. Mr. Kollen's analysis was restricted to non-fuel operation and maintenance expenses. In his prepared testimony, Mr. Kollen indicates that the $25,771,000 in operation and maintenance expenses over his benchmark calculation clearly shows that the growth in those expenses is out of control.[129] He advocates that the Commission adopt some form of cost containment, like the benchmark, as an incentive for LG&E.[130]

During the hearing, Mr. Kollen was cross-examined extensively about his benchmark approach. Mr. Kollen frequently referred to the Florida Public Service Commission ("Florida PSC") utilizing a benchmark approach similar to his proposal. While Mr. Kollen testified that the Florida PSC uses a benchmark approach in all general rate proceedings, he could not cite a rule, regulation, practice, or order which required such a filing.[131] While advocating the benchmark as a means of total operation and maintenance expense containment, Mr. Kollen readily accepted the fact that some functional areas of operation and maintenance expenses could continue to increase in exchange for reduction in

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128 Kollen Prepared Testimony, Exhibit LK-5 and Hearing Transcript, Vol. XI, pages 91-92.

129 Kollen Prepared Testimony, page 14.

130 Ibid., page 18.

131 Hearing Transcript, Vol. XI, pages 97-98.

other areas.[132] In computing the overall growth factor, Mr. Kollen used the change in the sales growth in his calculations although his testimony was that the Florida PSC uses the change in the customer growth.[133]

In its brief, KIUC stated that,

> . . . there is substantial evidence [emphasis added] indicating that the requested level of O & M expense is excessive even when given a liberal recognition of inflation and sales growth. In the absence of specific data [emphasis added] provided by the Company, the Commission should determine the reasonable level of recurring operation and maintenance expense using a benchmark methodology similar to that developed and utilized by the Kentucky Commission two cases ago.[134]

The Commission does not understand how there can be "substantial evidence" while at the same time be an "absence of specific data." In the case which KIUC has referenced to support the benchmark approach, the increase to wages and salaries was denied because of an evaluation of existing economic conditions; therefore, the Consumer Price Index was used as a substitute for the percent of wage increase allowed for rate-making purposes.[135] Thus, the example referred to differs significantly from the proposed benchmark as put forth by KIUC.

The benchmark approach to establishing a fair and reasonable level of expenses may be a useful tool in instances where the data is not available to make specific adjustments, or in abbreviated

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[132] Ibid., pages 100-102.

[133] Ibid., page 103.

[134] KIUC Brief, filed May 9, 1988, page 47.

[135] Case No. 8616, final Order dated March 2, 1983, pages 22-23.

filings or annual earnings adjustment cases allowed by some state regulatory bodies where time constraints are present. However, the Commission in its general rate proceedings, applies the standards of known and measurable as well as fair and reasonable in making adjustments to the historical test period. In this case, many adjustments have been made to reduce historical test year expenses where costs were deemed to be excessive, non-recurring, or otherwise inappropriate for rate-making purposes. The Commission believes that this approach is much more accurate and results in a more reasonable level of operating expenses. The case presented by KIUC on this issue is not conclusive. The Commission has decided not to use the benchmark approach proposed by KIUC in this general rate proceeding.

Gas Cost of Service

In accordance with the Commission's Order of May 29, 1987 in Administrative Case No. 297, An Investigation of the Impact of Federal Policy on Natural Gas to Kentucky Consumers and Suppliers, the Company prepared and filed a fully distributed, embedded gas cost of service study. The study's sponsor, Randall Walker, LG&E's Coordinator of Rates and Tariffs, described the methodology in his testimony,

> In order to allocate costs among the classes of service on the basis of cost incurrence and to determine the relative contribution that each class makes to the overall return on net gas rate base, costs were first assigned to functional groups, then classified as to demand, commodity, or customer-related, and finally, allocated to the classes of service.[136]

136 Walker Prepared Testimony, page 2.

The study shows that the residential class is being subsidized by all other rate classes of gas service.[137] According to this Exhibit, the adjusted return for the test year for residential service is a negative 0.79 percent, for nonresidential service, 11.93 percent, Fort Knox, 16.5 percent, and seasonal off-peak Rate G-6, 66.34 percent. LG&E stated in its brief that "such an imbalance is undesirable and should be improved."[138] As a result, LG&E is proposing rates which will result in a more equitable recovery of costs, thus reducing the differential in class rates of return. The Residential Intervenors contend that the reason for the residential class's negative return is that the study overstates the costs incurred by the residential class.[139] One example of overstated costs offered by the Residential Intervenors involves the method in which the costs of distribution mains are allocated. LG&E uses the zero-intercept methodology to classify the costs of distribution mains as either demand or customer related. "This methodology again disproportionately assigns costs to the residential class based on a theoretical system design which has no basis in reality."[140] Also critical of LG&E's use of the zero-intercept methodology was the DOD whose witness, Suhas P. Patwardhan, conversely charges that "use of the Company method

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137 Ibid., Exhibit 1, page 4.

138 LG&E Brief, May 9, 1988, page 64.

139 Residential Intervenors Brief, May 9, 1988, page 14.

140 Ibid., pages 14-15.

will result in favorable treatment for small usage customers as opposed to large usage customers."[141] Mr. Patwardhan feels that the use of a minimum-system method would result in a more favorable rate of return performance from large users such as Fort Knox.

The Commission is convinced that the zero-intercept method is theoretically sound and less subjective than the minimum system method, in which a minimum size main must be subjectively chosen in order to determine the customer component.

For the purpose of determining cost causation, LG&E separates its customers into four classes of service, Rate G-1-residential, Rate G-1-nonresidential, Fort Knox and Rate G-6-Seasonal Off-Peak service. This particular breakdown of rate classes evokes this criticism by the KIUC:

> Although LG&E has presented a "cost-of-service study," it is not appropriate because it fails to evaluate cost causation with respect to firm industrial sales customers as distinct from firm commercial sales customers and transportation service as distinct from sales service.[142]

KIUC further contends that the Company's study is contrary to the Commission's guidelines set forth in its Order in Administrative Case No. 297. On pages 42-43 of that Order, the following guidelines are stated, "The Commission prefers that the (cost of service) studies be disaggregated to the greatest extent possible."

Pursuant to its criticism of LG&E's gas cost of service study, KIUC, through its witness Kenneth Eisdorfer, presented an

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141 Patwardhan Prepared Testimony, page 7.

142 KIUC Brief, May 9, 1988, page 87.

alternative study. Mr. Eisdorfer's study disaggregates the Non-residential Rate G-1 category, used by LG&E, into Commercial G-1, Industrial G-1 (Sales), and Industrial G-1 (Transportation). Further, he disaggregates LG&E's Rate G-6 into Sales and Transportation classes of service. His study allocates gas stored underground exclusively to sales service. Otherwise, all cost assignment methodologies are identical to LG&E's.[143]

The Commission is of the opinion that KIUC's assertion that the Company did not fully disaggregate the various classes of service is a valid concern. The Commission will require LG&E to specifically address this issue in the gas cost of service study it files in its next rate case.

Except as described above, the Commission finds that the gas cost of service filed by LG&E provides an adequate starting point for rate design and should be used as the guide for the allocation of revenues to the customer classes.

Electric Cost of Service

LG&E filed an embedded time-differentiated cost of study that used a base-intermediate-peak ("BIP") method to allocate production and transmission demand related costs to costing periods and to customer classes. The methodology used by LG&E was essentially the same as has been used in the last two rate cases with the exception that some of the demand allocators were adjusted to account for temperature-sensitive demand. James W. Kasey,

143 Eisdorfer Prepared Testimony, page 11.

Coordinator of Rate Research for LG&E, sponsored the embedded cost of service study.

There was considerable concern expressed by the Residential Intervenors, County and CAG with the results of the electric cost of service study. Mr. Kinloch indicated his opposition to LG&E's use of the zero-intercept method for allocating distribution system costs between energy and customer related costs. He stated, "The use of a minimum system calculation assumes that all customers are the same, and that each customer contributes equally to the minimum system requirement."[144] He further contended that customers living in older neighborhoods were closer to generation stations with more fully depreciated infrastructure and contribute less to costs of the distribution system. Mr. Kinloch concluded that the minimum distribution grid costs should be allocated based on energy and recovered through a KWH charge.[145]

The Residential Intervenors expressed concern with LG&E's proposal to include weather normalization adjustment in its cost of service study. The Residential Intervenors contend that they are doubly affected by weather normalization because "the company increased the residential contribution to system peak demand over actual test year contribution to reflect a lower than 'normal' demand,"[146] plus "the company's proposed weather normalization reduced the revenues attributed to the residential class by $8.5

144 Kinloch Prepared Testimony, page 29.

145 Ibid., page 30.

146 Residential Intervenors Brief, page 12.

million."[147] Thus, the residential class rate of return is reduced to 6.25 percent for the adjusted test year which was below the system average of 8.67 percent. Therefore, the Residential Intervenors proposed that the, ". . . company cost of service study should not be used to assign a greater percentage of any increase to the residential than that assigned to the system as a whole."[148]

The Commission in its Order in Case No. 8924 accepted LG&E's proposed cost of service study's methodology. The Commission continues to be of the opinion that LG&E's BIP methodology is appropriate. Furthermore, the Commission will continue to accept the zero-intercept methodology for the allocation of distribution costs between customer and demand components of the cost of service study. This method is theoretically superior to the alternative proposed by the Residential Intervenors.

Though the Commission is of the opinion that LG&E's cost of service methodology is acceptable, the Commission has serious concerns with the class rate of return results. In this case, LG&E's witness testified that, ". . . the summer and winter system peaks used in this analysis were temperature normalized,"[149] and ". . . several of the demand allocation factors were normalized for the effects of temperature . . ."[150] In a previous section of

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147 Ibid., page 13.

148 Ibid., page 13.

149 Kasey Prepared Testimony, Exhibit 1, page 7.

150 Ibid., page 11.

this Order the Commission rejected the temperature normalization adjustment. The use of temperature normalized allocators and the temperature normalization adjustment of the winter and summer peaks result in improper allocations of costs to various classes, distorting class rate of return. Therefore, the Commission will reject the cost of service study for use as the basis for the allocation of revenues to the classes. Instead, the Commission will allocate the increase in revenue to each rate class in proportion to its overall increase in rates.

RATE DESIGN

Street Lighting

The City expressed concern about the financial impact of the proposed increased cost of the 400-watt mercury vapor street light with a wood pole. The Commission understands the concerns of the City and recognizes that inequities exist in the tariffs for mercury vapor street lights and the high pressure sodium vapor lights because the rates do not currently reflect cost of service. The Commission agrees with the analysis that LG&E prepared to reflect the movement toward cost-based rates in the street lighting structure. As the Commission has reduced the requested revenue increase by LG&E in this case, the Commission has also adjusted the rates of individual units in the street lighting tariff, which reflects a gradual movement to cost-based rates. The Commission advises the City and LG&E that LG&E should again analyze and update its street lighting tariff in its next rate case.

Disconnect and Reconnection Charge/Monthly Customer Charge

Mr. Kinloch, representing the County and the CAG, stated that the low income customers would be adversely affected by the proposed increases in the disconnect and reconnection charge ("fee") and the monthly customer charge ("charge").[151] Mr. Kinloch stated that the fee applies generally to the bills of the customers that are least able to pay the fee; that the fee is a cost of doing business; that all utilities, such as Louisville Water Company in Louisville and Jefferson County, do not charge such a fee; and that new customers are not charged a hookup fee. The Commission has considered the testimony of Mr. Kinloch and recognizes that this type of a fee by its nature will affect customers experiencing financial difficulties. The fee recovers a cost of business created by a minority of customers. Although Louisville Water Company may not exercise its right to charge this fee, that right is still in its rules and regulations. The Commission does not find that disconnect/reconnect service charges upon the customers creating the need for these services to be comparable to the provision of hookup service at no charge to every customer. While the Commission is sensitive to the concerns of those experiencing financial hardship, it recognizes that a fee of this type allocates costs to cost causers and is a fair and reasonable component of an electric utility rate design. The Commission has and will continue to consider the effects of this charge. In this case, the Commission has adjusted the proposed $4

151 Kinloch Prepared Testimony, page 22.

increase to $2 to reflect the approximate percent of decrease of LG&E's overall requested increase. The fee is to increase from $12 to $14.

Mr. Kinloch recommended that the monthly residential customer charge for electric service be reduced below the current monthly charge of $3.16 to $2.35 and the residential rate design be changed to a flat rate for the winter months and an inverted block rate for the summer months. Similarly, Mr. Kinloch recommended that the proposed monthly customer charge for gas services be reduced from $5.50 to $3.85. The Commission has accepted the cost of service methodologies proposed by LG&E for the Electric and Gas Divisions but has rejected the proposed weather normalization included in the Electric Division's cost of service study. Mr. Kinloch did not propose a complete cost of service analysis for either the Electric or Gas Division, and the proposed inverted block rate for electric is not a cost-based rate. The rate design as proposed by LG&E has been accepted in the past by the Commission.

The Commission is of the opinion that LG&E's proposed residential rate design appropriately reflects its costs and is fair to all parties. Therefore, considering the objectives of cost-based rates and rate continuity, the Commission has relied on LG&E's proposal in determining approved residential rates.

<u>Off-System Sales</u>

George Gerasimou, witness for KIUC, recommended that the Commission investigate the feasibility of flowing total revenue associated with off-system sales through the monthly fuel adjustment clause ("FAC").[152] He did not propose any adjustment to revenues or expenses in this case related to his proposed treatment of off-system sales. FAC revenues and expenses are reviewed in 6-month hearings under the Commission's regulation 807 KAR 5:056. That regulation is under review in Administrative Case No. 309, An Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056. The Commission is of the opinion that any revision to the FAC regulation should have been presented to the Commission for review in that case.

Revenue Increase Allocation

LG&E based its proposed allocation of revenue increase on its cost of service studies. The Commission has previously rejected the proposed electric cost of service analysis for reasons stated elsewhere in this Order; therefore, the Commission will allocate the allowed electric revenue increase in the proportions of the revised normalized class revenue to the total revised normalized revenue, as illustrated below.

	Revised Normalized Revenue	Percent	Allocation of Revenue Increase
Residential	$172,914,195	38.313	$ 4,900,514
General Service	66,230,541	14.675	1,877,040
Large Commercial	89,790,252	19.895	2,544,717
Large Industrial	91,697,158	20.317	2,598,694
Special Contracts	24,078,953	5.335	682,386
Street and Outdoor Lighting	6,611,828	1.465	187,384
Total Sales Customers	$451,322,927	100.000	$12,790,735
Other Electric Revenue	5,412,703		28,642
Total Electric Operating Revenue	$456,735,630		$12,819,377

152 Gerasimou Prepared Testimony, page 6, A16.

The Commission has accepted the gas temperature normalization and the other revenue adjustments as proposed by LG&E in the $166,068,711 total normalized gas operating revenues. The reduction in the allowed Gas Division revenue increase from the proposed revenue increase will be allocated among those rate classes that LG&E proposed revenue increases. LG&E proposed an extremely large percent increase to the monthly customer charge. The Commission is of the opinion that the proposed customer charges should be reduced to maintain rate continuity. Therefore, all of the reduction in proposed gas revenue increase is allocated to the customer charge. The allocation of the revenue increase is as follows.

Rate Class	Normalized Revenue	Allocation of Revenue Increase
Rate G-1		
Total Residential	$ 89,443,656	$ 8,394,853
Total Non Residential	55,672,127	2,085,578
Rate G-6	13,601,930	<1,324,103>
Rate G-7	106,520	<10,953>
Rate G-8		-0-
Fort Knox Contract	5,783,136	-0-
Total Sales and Transportation	$164,607,369	$ 9,145,375
Other Revenues	1,461,342	28,642
Total Gas Operating Revenues	$166,068,711	$ 9,174,017

Economic Development Rate

LG&E, through its witness, Fred Wright, has proposed an Economic Development Rate ("EDR") to be administered as a rider to LG&E's Large Commercial Rate - LC, Large Commercial Time-of-Day

Rate - LC-TOD, Industrial Power Rate - LP, and Industrial Power Time-of-Day Rate - LP-TOD. Mr. Wright described the purpose of this proposed rate in the following statements:

> LG&E strives to broaden the base of customers over which to spread its fixed costs, in order to keep its retail gas and electric rates as low as practicable so as to remain competitive for new business . . . The EDR is designed to stimulate the creation of new jobs and capital investment both by encouraging existing large commercial and industrial companies to remain in the area and to expand, and by making it more attractive for new companies to move into our service area.[153]

The proposed rate offers companies in the above rate classes, who increase their electric load demand by at least 1,000 Kilowatts over the base year load demand, a reduction to the billing demand during the 8 monthly billing periods from October through May in accordance with the following table:

Time Period	Reduction to Billing Demand
First 12 Months	50%
Second 12 Months	40%
Third 12 Months	30%
Fourth 12 Months	20%
Fifth 12 Months	10%
After 60 Months	0%

For purposes of this rider, the base year is defined as the most recent 12-month calendar year period ending before the effective date of this rider.

Mr. Wright further explains that, "Incentive rates are becoming increasingly common in utility rate tariffs in areas against which the Louisville area must compete."[154] In addition, Mr.

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153 Wright Prepared Testimony, page 3.

154 Wright Prepared Testimony, page 5.

Wright testified that "it (EDR) should not contribute unnecessarily to the Company's future capacity requirements but, rather should improve the Company's electric system load and capacity factors by encouraging growth in a customer class that has a higher load factor."[155] Several parties in this proceeding expressed concern with LG&E's proposed EDR. Mr. Kinloch testified that, although he was not opposed to economic development and the creation of jobs, he is concerned about the mechanism by which LG&E has proposed to address these issues -- the EDR. The first point of concern he raised is that "the EDR rate is below cost of service pricing."[156] Secondly, he expressed apprehension about the potential for success of the EDR and concern with the lack of formal evaluation proposed by LG&E. Finally, Mr. Kinloch addresses the effect, he feels, the EDR will have on LG&E's low-income customers. "While there may be some benefit for a younger low-income customer who is unemployed, the EDR rate will provide absolutely no benefit for elderly customers on fixed incomes."[157] Mr. Kinloch likens the EDR to a lifeline rate proposed for industry instead of to the low-income customers. He suggests that the Commission approve the EDR only if LG&E offers a lifeline rate to elderly customers on fixed incomes.

The Residential Intervenors, during the cross examination of Mr. Wright, raised the concern with the manner in which LG&E will

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155 Ibid., page 6.

156 Kinloch Prepared Testimony, page 45.

157 Ibid., page 47.

determine the normality of whether base year demand, above which an additional one megawatt will qualify an LC, LC-TOD, LP, or LP-TOD rate customer for the EDR. Specifically, they were concerned with whether there were unusual circumstances in the base year that would cause a customer's demand to be lower than it would normally be.[158] Mr. Wright responded that each qualifying customer must convince LG&E that he has created jobs and capital investment, and that no unusual circumstances exist in the base year. LG&E did not propose, nor does the EDR rider address, the mechanism by which either of these conditions will be satisfied.

Throughout the record in this case, LG&E has maintained a dual purpose in proposing the EDR: creating additional load, and creating new jobs and new capital investment. The Commission believes that the two purposes are complements. However, the Commission also believes that the concern raised by the intervenors, that LG&E has proposed no mechanism in its EDR to determine that both of these purposes are being addressed, is valid.

The Commission also finds merit with the following concerns raised by the intervenors and its Staff regarding the EDR:

1. The possibility that the EDR is priced below cost of service.

2. The lack of any formal evaluation by LG&E of the effects of the EDR if it is implemented.

3. The effect the EDR will have on LG&E's other ratepayers.

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158 Hearing Transcript, Vol. II, page 222.

4. The fact that the EDR rider does not specify how to determine if base year demand is abnormal or how to determine the effect of the EDR on job creation and capital investment.

5. Whether the EDR should be implemented via a tariff or by special contracts.[159]

There has been a substantial increase in the number of economic development/incentive rates filed with the Commission by both electric and gas utilities during the past year. The purpose of these tariffs, according to the utilities, is to increase the amount of energy sold and/or to expand the level of capital investment and employment in the sponsoring utility's service area. Though the rate designs may vary drastically by utility, they typically provide demand discounts for new and expanding industries within the utility's service area for some specified time period, typically 5 years.

At the current time, the Commission has before it, in addition to LG&E's proposed EDR rider, several economic development/incentive rate proposals. Each of the various tariffs and contracts will require a Commission decision for implementation. Because of the potential volume of tariff and contract filings and their impact on the utility and their customers, the Commission is of the opinion that a consistent policy should be developed on tariff filing and reporting requirements.

The Commission finds that the concerns raised by the parties in the instant case, the number of tariffs and contracts presently

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[159] Hearing Transcript, Vol. II, pages 251-253 and 255-256.

under consideration, and the potential implications of these proposals necessitate that utilities which offer economic development/incentive rates to existing or potential customers must satisfy the following requirements, prior to Commission approval of the proposed rate:

1. Each utility should be required to provide an affirmative declaration and evidence to demonstrate that it has adequate capacity to meet anticipated load growth each year in which an incentive tariff is in effect.

2. Each utility should be required to demonstrate that all variable costs associated with the transaction during each year that the contract is in effect will be recovered and that the transaction makes some contribution to fixed costs. Furthermore, the customer-specific fixed costs associated with adding an economic development/incentive customer should be recovered either up front or as a part of the minimum bill over the life of the contract.

3. Each utility that offers an economic development rate should be required to document and report any increase in employment and capital investment resulting from the tariff and contract. These reports should be filed on an annual basis with the Commission.

4. Each utility that intends to offer economic incentive rates should be required to file a tariff stating the terms and conditions of its offering. Furthermore, each utility should be required to enter into a contract with each customer which specifies the minimum bill, estimated annual load, and length of

contracting period. No contract should exceed 5 years. All contracts shall be subject to the review and approval of the Commission.

5. Each utility should be required to include a clause in its contract that states that the tariff will be withdrawn when the utility no longer has adequate reserve to meet anticipated load growth.

6. Each utility should be required to demonstrate that rate classes that are not party to the transaction should be no worse off than if the transaction had not occurred. Under special circumstances, the Commission will consider utility proposals for contracts that share risk between utility shareholders and other ratepayers. However, if a utility proposes to charge the general body of ratepayers for the revenue deficiency resulting from the EDR through a risk-sharing mechanism then the utility will be required to demonstrate that these ratepayers should benefit in both the short- and long-run. In addition, at least one-half of the deficiency will be absorbed by the stockholders of the utility and will not be passed on to the general body of ratepayers. The amount of the deficiency will be determined in future rate cases by multiplying at least one-half of the billing units of the EDR contract(s) by the tariffed rate that would have been applied to customer(s) if the EDR contract(s) had not been in effect.

The Commission is of the opinion that these restrictions on economic development/incentive rates will provide a means for protecting other ratepayers while still providing LG&E, other utilities, and industrial development specialists the opportunity to use lower rates to attract industry.

Furthermore, the Commission is of the opinion and finds that the EDR rider proposed by LG&E is partially consistent with Requirement 4 above. However, the rider must be revised to include language making it completely consistent with all of the above requirements. Therefore, LG&E should withdraw the EDR rider in its present form and refile it within 30 days after all revisions have been made.

Cogeneration and Small Power Production Tariffs

Pursuant to the Order in Case No. 8566, Setting Rates and Terms and Conditions of Purchase of Electric Power from Small Power Producers and Cogenerators by Regulated Electric Utilities, LG&E filed tariffs reflecting its proposed avoided energy and capacity costs. Robert Lyon, Manager of System Planning and Budgets, sponsored the avoided cost studies and tariffs. In preparing estimates of avoided energy costs, LG&E used "its more detailed production costing model, PROMOD III, in place of the EBASCO model (MARCOST 80)." Similarly, in preparing estimates of avoided capacity costs, "computer models used in the Company's recent capacity expansion study were used, v12., EGEAS (Electric Generation Expansion Analysis System) and TALARR (Total and Levelized Annual Revenue Requirements)." Both models are widely accepted and used in the electric utility industry.

In preparing its estimate of avoided capacity costs, LG&E used, "[T]wo twenty-year strategic expansion plans . . ." One plan assumed qualifying facilities with 75,000 KW capacity with an availability of 70 percent and no capacity costs while the other plan did not. The use of Qualifying Facility ("QF") capacity by LG&E resulted in both cancellation and deferment of combustion turbine capacity in its 20-year planning cycle. The difference in the present worth of revenue requirements ("PWRR") between the two plans represented the avoided capacity costs of QF capacity since only the fixed costs of plant ownership were considered in the PWRR analysis. Using a levelized annual revenue requirement of $1,910,000 and assuming 70 percent availability and must run QF operational characteristics, Mr. Lyon proposed a capacity purchase payment of 4.15 mills per KWH. Finally, Mr. Lyon indicated that a QF would have to contract for 20 years to qualify for the proposed capacity purchase payment. In addition, LG&E proposed that each QF be required to post a bond to insure that capacity will be offered for the duration of the contract.

In preparing its avoided energy costs, LG&E used essentially the same method as it used in preparing its estimates in Case No. 8566. Using PROMOD III, LG&E estimated its avoided energy costs at 2.04 cents per KWH. Mr. Lyon indicated that LG&E would apply this avoided energy cost to all QF purchases regardless of whether it was under a 20-year contract or not. He further indicated that LG&E would update its estimates of avoided energy costs and its energy purchase rates annually, and avoided capacity costs and capacity purchase rates updates biannually. Finally, Mr. Lyon indicated that the revised rates would apply to all QF purchases.

The Commission is of the opinion and finds that the proposed rates resulting from the avoided costs are consistent with the

Commission's Order in Case No. 8566. Furthermore, the rates reflect LG&E avoided costs and should be adopted. However, the Commission does intend to continue to monitor LG&E bonding requirements to insure that the requirements do not discourage or hinder QF development.

Natural Gas Tariffs

KIUC proposes that LG&E's gas tariffs be revised to reflect the costs incurred by the utility in serving different customers.[160] KIUC states that the cost of service study LG&E has submitted is deficient "because it fails to evaluate cost causation with respect to firm industrial sales customers as distinct from firm commercial sales customers and transportation service as distinct from sales service."[161] KIUC states that the result of LG&E's revenue proposals for transportation customers will be to earn from these classes an excessive rate of return. KIUC's proposed solution is to utilize the cost of service study presented by its witness, Mr. Eisdorfer.

KIUC's conclusions are based upon the differences between its cost of service study and the one submitted by LG&E. The Commission discusses the two studies elsewhere in this Order in the section entitled Gas Cost of Service, wherein the Commission concludes that these issues raised by KIUC are a valid concern. However, the Commission has decided to have LG&E disaggregate the various classes of service more fully in the gas cost of service

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160 KIUC Brief, filed May 9, 1988, page 87.

161 Ibid., page 86.

study it files in its next rate case. Therefore, it would be inappropriate to order any tariff changes the support for which would require a greater disaggregation between classes than that accepted by the Commission in LG&E's cost of service study.

KIUC also proposes that certain changes be made to LG&E's proposed tariff Rate T applicable to gas transportation service. KIUC states that the proposed language ". . . does not conform with Mr. Hart's representation . . . that transportation service provided under Rate T would be firm and that the language should be corrected by substituting the word "converted" for the word "reduction . . ."[162] KIUC also believes that certain language under the "availability" part of this tariff should be changed to conform to certain provisions in the Order issued in Administrative Case No. 297. Specifically, KIUC argues that the language should clearly state: LG&E has the obligation to tell a prospective transportation customer why it cannot transport gas; and the burden of proof is on LG&E to show that capacity does not exist on its system to transport gas.[163]

The Commission is of the opinion that the proposed language in LG&E's gas tariffs is sufficient to allow a prospective gas customer to understand the services offered and their terms and conditions. The Commission also finds that it is unnecessary for LG&E to substitute the word "converted" for the word "reduction" in the Rate T tariff. LG&E's proposed language allows its

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162 Hearing Transcript, Vol. VI, page 93.

163 Ibid., page 94.

transportation customers to receive transportation service under Rate T as long as LG&E's D-1 and D-2 billing demands from its pipeline supplier are reduced in an amount corresponding to the volumes of gas transported. The Commission understands KIUC's point to be that an end-user through its supplier may request a reduction or conversion of some portion of its supply in order to increase the amount of transportation it can utilize. LG&E agrees that an end-user may request either a reduction or conversion.[164] However, in either case, LG&E must receive a reduction in its billing demands which represent the reduced or converted sales volumes. Otherwise, LG&E's non-transportation customers would ultimately pay the billing demands for those sales volumes not purchased by such an end-user.

Regarding the "availability" section of the Rate T tariff, the Commission does not view the current language as relieving LG&E of its burden of proof. LG&E agrees with the points raised by KIUC.[165] However, the Commission is of the opinion that the language should be clarified to provide prospective transportation customers in a clearer understanding of LG&E's responsibilities. Therefore, LG&E should revise the language in the "availability" section of the Rate T tariff to more clearly comply with the Order issued in Administrative Case No. 297.

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164 Hearing Transcript, Vol. VI, pages 78-79.

165 Ibid., pages 85-86.

Effective Date of New Rates

LG&E's proposed rates were filed with an effective date of December 20, 1987. Pursuant to KRS 278.190(2), the Commission suspended the operation of the proposed schedules for a period of 5 months, until May 20, 1988. On May 19, 1988, LG&E filed a motion stating that if the Commission has not ruled on its rate application by May 20, 1988, LG&E would forego its right to place the proposed rates in effect subject to refund provided that the new rates when authorized will be made effective on May 20, 1988. None of the intervenors objected to this motion and the Commission granted it by Order issued May 20, 1988.

In accordance with that Order, the rates authorized herein are being made effective for service rendered on and after May 20, 1988. With respect to a surcharge to permit LG&E to recover the new rates from May 20, 1988 through the effective date of this Order, LG&E's motion proposed that the surcharge be applied to billings spread over an extended period of time not to exceed December 31, 1988. On June 20, 1988, the Commission received a letter from LG&E proposing that the surcharge be applied only to billings for one month. The Residential Intervenors notified the Commission on June 28, 1988 that it objected to LG&E's proposed modification. The Commission is of the opinion that LG&E should file a surcharge plan within 30 days from the date of this Order. All parties will then be afforded 15 days to file comments on the plan.

SUMMARY

The Commission, after consideration of the evidence of record and being advised, is of the opinion and finds that:

1. The rates in Appendix A are the fair, just, and reasonable rates for LG&E and will produce gross annual revenues based on adjusted test year sales of approximately $644,776,975.

2. The rate of return granted herein is fair, just, and reasonable and will provide for the financial obligations of LG&E with a reasonable amount remaining for equity growth.

3. The rates proposed by LG&E would produce revenue in excess of that found reasonable herein and should be denied upon application of KRS 278.030.

4. The proposed EDR tariff rider should be withdrawn and resubmitted for review when the revisions discussed herein have been made.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix A be and they hereby are approved for service rendered by LG&E on and after May 20, 1988.

2. The rates proposed by LG&E be and they hereby are denied.

3. The proposed EDR tariff rider shall be resubmitted when LG&E has made necessary revisions.

4. Within 30 days from the date of this Order, LG&E shall file with the Commission its revised tariff sheets setting out the rates approved herein.

5. LG&E shall file a surcharge plan within 30 days of the date of this Order and intervenors shall have until 15 days thereafter to file comments.

Done at Frankfort, Kentucky, this 1st day of July, 1988.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988.

The following rates and charges are prescribed for the customers in the area served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE

RESIDENTIAL RATE
(RATE SCHEDULE R)

RATE:

Customer Charge: $3.25 per meter per month.

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

First 600 kilowatt-hours per month	6.023¢ per Kwh
Additional kilowatt-hours per month	4.717¢ per Kwh

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month	6.593¢ per Kwh

WATER HEATING RATE
(RATE SCHEDULE WH)

RATE: 4.761¢ per kilowatt-hour.

Minimum Bill $2.05 per month per heater

GENERAL SERVICE RATE*
(RATE SCHEDULE GS)

RATE:

Customer Charge:

$3.85 per meter per month for single-phase service
$7.70 per meter per month for three-phase service

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

All kilowatt-hours per month 6.454¢ per Kwh

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month 7.232¢ per Kwh

Minimum Bill:

The minimum bill for single-phase service shall be the customer charge.

The minimum bill for three-phase service shall be the customer charge; provided, however, in unusual circumstances where annual kilowatt-hour usage is less than 1,000 times the kilowatts of capacity required, Company may charge a minimum bill of not more than 98 cents per month per kilowatt of connected load.

SPECIAL RATE FOR ELECTRIC SPACE HEATING SERVICE RATE SCHEDULE GS

RATE:

For all consumption recorded on the separate meter during the heating season the rate shall be 4.726¢ per kilowatt-hour.

Minimum Bill:

$6.90 per month for each month of the "heating season." This minimum charge is in addition to the regular monthly minimum of Rate GS to which this rider applies.

LARGE COMMERCIAL RATE (RATE SCHEDULE LC)

Applicable:

In all territory served.

Availability:

This schedule is available for alternating current service to customers whose monthly demand is less than 2,000 kilowatts and whose entire lighting and power requirements are purchased under this schedule at a single service location.

RATE:

Customer Charge: $16.90 per delivery point per month.

Demand Charge:

	Secondary Distribution	Primary Distribution
Winter Rate: (Applicable during 8 monthly billing periods of October through May)		
All kilowatts of billing demand	$7.25 per Kw per month	$5.61 per Kw per month
Summer Rate: (Applicable during 4 monthly billing periods of June through September)		
All kilowatts of billing demand	$10.33 per Kw per month	$8.42 per Kw per month

Energy Charge:

All kilowatt-hours per month 3.272¢

LARGE COMMERCIAL TIME-OF-DAY RATE

Availability:

This schedule is available for alternating current service to customers whose monthly demand is equal to or greater than 2,000 kilowatts and whose entire lighting and power requirements are purchased under this schedule at a single service location.

RATE:

Customer Charge: $17.20 per delivery point per month

Demand Charge:

Basic Demand Charge
- Secondary Distribution $3.68 per Kw per month
- Primary Distribution $1.99 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period but not less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Peak Period Demand Charge

Summer Peak Period	\$6.66 per Kw per month
Winter Peak Period	\$3.54 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Energy Charge: 3.272¢ per Kwh

Winter-Peak Period is defined as weekdays, except holidays as recognized by company, from 6 AM to 10 PM local time, during the 8 monthly billing periods of October through May.

INDUSTRIAL POWER
(RATE SCHEDULE LP)

Availability:

This schedule is available for three-phase industrial power and lighting service to customers whose monthly demand is less than 2,000 kilowatts, the customer to furnish and maintain all necessary transformation and voltage regulatory equipment required for lighting usage. As used herein the term "industrial" shall apply to any activity engaged primarily in manufacturing or to any other activity where the usage for lighting does not exceed 10% of total usage.

RATE:

Customer Charge: \$41.70 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution	Transmission Line
All kilowatts of billing demand	\$8.99 per Kw per month	\$7.02 per Kw per month	\$5.86 per Kw per month

Energy Charge:

All kilowatt-hours per month 2.832¢ per Kwh

INDUSTRIAL POWER TIME-OF-DAY RATE
(RATE SCHEDULE LP-TOD)

Applicable:

In all territory served.

Availability:

This schedule is available for three-phase industrial power and lighting service to customers whose monthly demand is equal to or greater than 2,000 kilowatts, the customer to furnish and maintain all necessary transformation and voltage regulatory equipment required for lighting usage. As used herein the term "industrial" shall apply to any activity engaged primarily in manufacturing or to any other activity where the usage for lighting does not exceed 10% of total usage. Company reserves the right to decline to serve any new load of more than 50,000 kilowatts under this rate schedule.

RATE:

Customer Charge: $42.55 per delivery point per month

Demand Charge:

Basic Demand Charge:	
Secondary Distribution	$5.26 per Kw per month
Primary Distribution	$3.30 per Kw per month
Transmission Line	$2.10 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period, but not less than 70% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Peak Period Demand Charge:	
Summer Peak Period	$5.51 per Kw per month
Winter Peak Period	$2.92 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 70% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Energy Charge: 2.832¢ per Kwh

Summer-Peak Period is defined as weekdays, except holidays as recognized by Company, from 9 AM to 11 PM local time, during the 4 monthly billing periods of June through September.

Winter-Peak Period is defined as weekdays, except holidays as recognized by Company, from 6 AM to 10 PM local time during the 8 monthly billing periods of October through May.

Power Factor Provision

The monthly demand charge shall be decreased .4% for each whole one percent by which the monthly average power factor exceeds 80% lagging and shall be increased .6% for each whole one percent by which the monthly average power factor is less than 80% lagging.

OUTDOOR LIGHTING SERVICE
(RATE SCHEDULE OL)

RATES:

Overhead Service Mercury Vapor	Rate Per Light Per Month
100 watt*	$6.92
175 watt	7.89
250 watt	8.98
400 watt	11.03
400 watt floodlight	11.03
1000 watt	20.38
1000 watt floodlight	20.38
High Pressure Sodium Vapor	
150 watt	$9.89
150 watt floodlight	9.89
250 watt	11.73
400 watt	12.55
400 watt floodlight	12.55
Underground Service **Mercury Vapor**	
100 Watt - Top Mounted	$12.00
175 Watt - Top Mounted	12.83
High Pressure Sodium Vapor	
100 Watt - Top Mounted	$14.14

* Restricted to those units in service on 5-31-79.

Special Terms and Conditions:

Company will furnish and install the lighting unit complete with lamp, fixture or luminaire, control device and mast arm. The above rates for overhead service contemplate installation on an existing wood pole with service supplied from overhead circuits only; provided, however, that when possible, floodlights served hereunder may be attached to existing metal street lighting standards supplied from overhead service. If the location of an existing pole is not suitable for the installation of a lighting unit, the Company will extend its secondary conductor one span and install an additional pole for the support of such unit. The customer to pay an additional charge of $1.62 per month for each such pole so installed. If still further poles or conductors are required to extend service to the lighting unit, the customer will be required to make a non-refundable cash advance equal to the installed cost of such further facilities.

PUBLIC STREET LIGHTING SERVICE
(RATE SCHEDULE PSL)

RATE:

TYPE OF UNIT

Overhead Service	Support	Rate Per Light Per Year
100 Watt Mercury Vapor (open bottom fixture)(1)	Wood Pole	$74.57
175 Watt Mercury Vapor	Wood Pole	88.03
250 Watt Mercury Vapor	Wood Pole	100.76
400 Watt Mercury Vapor	Wood Pole	121.45
400 Watt Mercury Vapor (2)	Metal Pole	174.02
400 Watt Mercury Vapor Floodlight	Wood Pole	121.45
1000 Watt Mercury Vapor	Wood Pole	228.43
1000 Watt Mercury Vapor Floodlight	Wood Pole	228.43
150 Watt High Pressure Sodium	Wood Pole	107.36
150 Watt High Pressure Sodium Floodlight	Wood Pole	107.36
250 Watt High Pressure Sodium	Wood Pole	129.36

400 Watt High Pressure Sodium	Wood Pole	136.21
400 Watt High Pressure Sodium Floodlight	Wood Pole	136.21
<u>Underground Service</u>		
100 Watt Mercury Vapor Top Mounted		121.65
175 Watt Mercury Vapor Top Mounted		133.73
175 Watt Mercury Vapor	Metal Pole	179.67
250 Watt Mercury Vapor	Metal Pole	192.87
400 Watt Mercury Vapor	Metal Pole	228.09
400 Watt Mercury Vapor	Alum. Pole	228.09
400 Watt Mercury Vapor on State of KY Aluminum Pole		137.14
100 Watt High Pressure Sodium Top Mounted		133.73
250 Watt High Pressure Sodium Vapor	Metal Pole	245.48
250 Watt high Pressure Sodium Vapor	Alum. Pole	245.48
250 Watt High Pressure Sodium Vapor on State of KY Aluminum Pole		127.19
400 Watt High Pressure Sodium Vapor	Metal Pole	264.89
400 Watt High Pressure Sodium Vapor	Alum. Pole	264.89
1500 Lumen Incandescent (3)	8-1/2' Metal Pole	99.01
6000 Lumen Incandescent (3)	Metal Pole	131.99

(1) Restricted to those units in service on 5/31/79
(2) Restricted to those units in service on 1/19/77
(3) Restricted to those units in service on 3/1/67

STREET LIGHTING ENERGY RATE
(RATE SCHEDULE SLE)

RATE:

4.021¢ per kilowatt-hour

TRAFFIC LIGHTING ENERGY RATE
(RATE SCHEDULE TLE)

RATE:

5.327¢ per kilowatt-hour

Minimum Bill:

$1.45 per month for each point of delivery.

INTERRUPTIBLE SERVICE

Applicable:

To Large Commercial Rate LC, Rate LC-TOD, Industrial Power Rate LP and Rate LP-TOD.

Availability:

This rider is available for interruptible service to any customer whose interruptible demand is at least 1,000 kilowatts.

Contract Demand:

The contract shall be for a given amount of firm demand which shall be billed at the appropriate standard rate schedule demand charge. Any excess monthly demands above this firm demand shall be considered as interruptible demand.

Rate:

The monthly bill for service under this rider shall be determined in accordance with the provisions of Rate LC, Rate LC-TOD, Rate LP or Rate LP-TOD, except there shall be an interruptible demand credit determined in accordance with one of the following categories of interruptible service:

Interruptible Service Categories	Maximum Annual Hours of Interruption	Monthly Demand Credit ($/Kw/Mo)
1	150	1.18
2	200	1.57
3	250	1.94

The interruptible demand credit shall be applied to the monthly billing demand in excess of the firm contract demand (but not less than 1,000 kilowatts) determined in accordance with the billing demand provision under the applicable rate schedule, except in the case of service under Rate LC-TOD or Rate LP-TOD. The interruptible credit shall be applied to the billing demands as determined for the peak periods only.

Interruption of Service:

The Company will be entitled to require customer to interrupt service at any time and for any reason upon providing at least 10 minutes prior notice. Such interruption shall not exceed 10 hours duration per interruption.

Penalty for Unauthorized Use:

In the event customer fails to comply with a Company request to interrupt either as to time or amount of power used, the customer shall be billed for the monthly billing period of such occurrence at the rate of $15.00 per kilowatt of monthly billing demand. Failure to interrupt may also result in the termination of the contract.

Term of Contract:

The minimum original contract period shall be one year and thereafter until terminated by giving at least 6 months previous written notice, but Company may require that contract be executed for a longer initial term when deemed necessary by the size of the load or other conditions.

Applicability of Terms:

Except as specified above, all other provisions of Rate LC, Rate LC-TOD, Rate LP and Rate LP-TOD shall apply.

SUPPLEMENTAL OR STANDBY SERVICE

Applicable:

To Large Commercial Rate LC, Rate LC-TOD, Industrial Power Rate LP and Rate LP-TOD.

Rate:

Electric service actually used each month will be charged for in accordance with the provisions of the applicable rate schedule; provided, however, that the monthly bill shall in no case be less than an amount calculated at the rate of $5.61 per kilowatt applied to the contract demand.

Special Terms and Conditions:

d. In the event customer's use of service is intermittent or subject to violent fluctuations, the Company will require customer to install and maintain at his own expense suitable equipment to satisfactorily limit such intermittence or fluctuations.

SMALL POWER PRODUCTION AND COGENERATION
PURCHASE SCHEDULE
SPPC-1

Rates for Purchases from
Qualifying Facilities

Capacity component per kilowatt-hour delivered .415¢

Term of Contract:

For contracts which cover the purchase of energy only, the term shall be one year and shall be self-renewing from year to year thereafter, unless cancelled by either party on one year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be 20 years.

SMALL POWER PRODUCTION AND COGENERATION
PURCHASE SCHEDULE
SPPC-II

Rates for Purchases from
Qualifying Facilities

Capacity component per kilowatt-hour delivered .415¢

Term of Contract:

For contracts which cover the purchase of energy only, the term shall be one year and shall be self-renewing from year to year thereafter, unless cancelled by either party on one year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be 20 years.

SPECIAL CONTRACT FOR ELECTRIC SERVICE
ARICO ALLOYS AND CARBIDE SPECIAL CONTRACT

Demand Charge

Primary Power (28,500 Kw)	\$11.37 per Kw per month
Secondary Power (Excess Kw)	\$5.69 per Kw per month
Demand Credit for Primary Interruptible Power (24,500 Kw)	\$1.94 per Kw per month
Energy Charge All KWH	2.005¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
E. I. DUPONT DE NEMOURS SPECIAL CONTRACT

Demand Charge

\$11.02 per Kw of billing demand per month

Energy Charge

2.128¢ per Kwh

SPECIAL CONTRACT FOR ELECTRIC SERVICE
FORT KNOX SPECIAL CONTRACT

Demand Charge

Winter Rate:
(Applicable during 8 monthly billing periods of October through May)

All Kw of Billing Demand	\$6.24 per Kw per month

Summer Rate:
(Applicable during 4 monthly billing periods of June through September)

All Kw of Billing Demand	\$8.42per Kw per month
Energy Charge: All Kwh per month	2.742¢ per Kwh

SPECIAL CONTRACT FOR ELECTRIC SERVICE
LOUISVILLE WATER COMPANY SPECIAL CONTRACT

Demand Charge

\$7.53 per Kw of billing demand per month

Energy Charge

2.261¢ per Kwh

GENERAL RULES

Charge for Disconnecting and Reconnecting Service:

23. A charge of $14.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of the Company's rules and regulations, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

Residential and general service customers may request and be granted a temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $14.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

GAS SERVICES

The Gas Supply Cost component in the following rates has been adjusted to incorporate all changes through PGA 8924-R.

GENERAL GAS RATE
G-1

Curtailment Rules

Delete specific reference.

Availability:

Available for general service to residential, commercial and industrial customers.

Rate:

Customer Charge:

$4.55 per delivery point per month for residential service
$9.25 per delivery point per month for non-residential service

Charge Per 100 Cubic Feet:

Distribution Cost Component	10.820¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	37.802¢

Off-Peak Pricing Provision:

The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by 5.0 cents per 100 cubic feet during the 7 monthly off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE G-1

Availability:

Available to any customer who takes gas service under Rate G-1 and who has installed and in regular operation a gas burning summer air conditioning system with a cooling capacity of three tons or more. The special rate set forth herein shall be applicable during the 5 monthly billing periods of each year beginning with the period covered by the regular June meter reading and ending with the period covered by the regular October meter reading.

Rate:

The rate for "Summer Air Conditioning Consumption," as described in the manner hereinafter prescribed, shall be as follows:

Charge Per 100 Cubic Feet:

Distribution Cost Component	5.820¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	32.802¢

All monthly consumption other than "Summer Air Conditioning Consumption" shall be billed at the regular charges set forth in Rate G-1.

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheets No. 12, 13 and 14 of this Tariff.

SEASONAL OFF-PEAK GAS RATE
G-6

Curtailment Rules

Delete specific reference.

Availability:

Available during the 275-day period from March 15 to December 15 of each year to commercial and industrial customers using over 50,000 cubic feet of gas per day who can be adequately served from the Company's existing distribution system without impairment of service to other customers and who agree to the complete discontinuance of gas service for equipment served hereunder and the substitution of other fuels during the 3-month period from December 15 to March 15. No gas service whatsoever to utilization equipment served hereunder will be supplied or permitted to be taken under any other of the Company's gas rate schedules during such 3-month period. Any gas utilization equipment on customer's premises of such nature or used for such purposes that gas service thereto cannot be completely discontinued during the period from December 15 to March 15 will not be eligible for service under this rate, and gas service thereto must be segregated from service furnished hereunder and supplied through a separate meter at the Company's applicable standard rate for year-around service. This rate shall not be available for loads which are predominantly space heating in character or which do not consume substantial quantities of gas during the summer months.

Rate:

Customer Charge: $20.00 per delivery point per month

Charge Per 100 Cubic Feet:

Distribution Cost Component	5.300¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	32.282¢

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

Minimum Bill:

The customer charge.

Prompt Payment Provision:

The monthly bill will be rendered at the above net charges (including net minimum bills when applicable) plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within 15 days from date.

RATE FOR UNCOMMITTED GAS SERVICE G-7

Rate:

Charge Per 100 Cubic Feet:

Distribution Cost Component	4.300¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	31.282¢

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

Incremental Pricing:

Delete from Tariff.

DUAL-FUEL OFF-PEAK GAS SPACE HEATING RATE
G-8

Service to be supplied under G-1.

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE
G-8

Service to be supplied under G-1.

GAS TRANSPORTATION SERVICE/STANDBY
RATE TS

Availability:

Available to commercial and industrial customers served under Rates G-1 and G-6 who consume at least 50 Mcf per day at each individual point of delivery, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's natural gas supplier, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any transportation service hereunder will be conditioned on the Company being able to retain or secure adequate standby quantities of natural gas from its supplier. In addition, transportation service hereunder shall be subject to the terms and conditions herein set forth and to the reserved right of Company to decline to initiate such service whenever, in Company's sole judgment, the performance of the service would be contrary to good operating practice or would have a detrimental impact on other customers served by Company.

Rate:

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $90.00 per delivery point per month.

	G-1	G-6
Distribution Charge Per Mcf	$1.0820	$0.5300
Pipeline Supplier's Demand Component	.4671	.4671
Total	$1.5491	$0.9971

The "Distribution Charge" applicable to G-1 monthly quantities in excess of 100 Mcf shall be reduced by $.50 per Mcf during the 7 off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component:

Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's quarterly Gas Supply Clause.

Standby Service:

Company will provide standby quantities of natural gas hereunder for purposes of supplying customers' requirements should customer be unable to obtain sufficient transportation volumes. Such standby service will be provided at the same rates and under the same terms and conditions as those set forth in the Company's applicable rate schedule under which it sells gas to customer.

Receipts and Deliveries:

Customer shall not cause quantities of gas to be delivered to Company's system which exceed the quantities delivered to the customer's place of utilization by more than 5%. Any imbalance between receipts by Company on behalf of customer and quantities delivered to customer shall be corrected as soon as practicable, but in no event shall imbalance be carried longer than 60 days.

Special Terms and Conditions:

(2) At least 10 days prior to the beginning of each month, customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for customer's account. Customer shall give Company at least 24 hours prior notice of any subsequent changes to scheduled deliveries. Customer shall cause gas delivered into Company's system for customer's account to be as nearly as practicable at uniform daily rates of flow, and deliveries of such gas by Company to customer hereunder will also be effected as nearly as practicable on the same day as the receipt thereof.

GAS TRANSPORTATION SERVICE
RATE T

Applicable:

In all territory served.

Availability:

Available to commercial and industrial customers served under Rate G-7 who consume at least 50 Mcf per day at each individual point of delivery, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's natural gas supplier, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any such transportation service hereunder shall be conditioned on the Company being granted a reduction in D-1 and D-2 billing demands by its pipeline supplier corresponding to the customer's applicable transportation quantities. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the reserved right of Company to decline to initiate such service whenever, in Company's sole judgment, the performance of the service would be contrary to good operating practice or would have a detrimental impact on other customers served by Company.

Rate:

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $90.00 per delivery point per month.

Distribution Charge Per Mcf: $0.43

Receipts and Deliveries:

Customer will deliver or cause to be delivered daily and monthly quantities of natural gas to Company's system which correspond to the daily and monthly quantities delivered hereunder by Company to customer's place of utilization and, in no case, shall the variation in quantities be greater than 5%. Any imbalance between receipts by Company on behalf of customer and quantities delivered to customer shall be corrected as soon as practicable, but in no event shall imbalance be carried longer than 60 days.

Special Terms and Conditions:

(1) Service under this rider shall be performed under a written contract between customer and Company setting forth specific arrangements as to volumes to be transported by Company for customer, points of delivery, methods of metering, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

(2) At least 10 days prior to the beginning of each month, customer shall provide Company with a schedule setting forth daily

volumes of gas to be delivered into Company's system for customer's account. Customer shall give Company at least 24 hours prior notice of any subsequent changes to scheduled deliveries. Customer shall cause gas delivered into Company's system for customer's account to be as nearly as practicable at uniform daily rates of flow, and deliveries of such gas by Company to customer hereunder will also be effected as nearly as practicable on the same day as the receipt thereof. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

(3) In no case will Company be obligated to supply greater quantities hereunder than those specified in the written contract between customer and Company.

(4) Volumes of gas transported hereunder will be determined in accordance with Company's measurement as set forth in the general rules of this Tariff.

(5) All volumes of natural gas transported hereunder shall be of the same quality and meet the same specifications as that delivered to Company by its pipeline supplier.

(6) Company will have the right to curtail or interrupt the transportation or delivery of gas to any customer hereunder when, in the Company's judgment, such curtailment is necessary to enable Company to maintain deliveries to residential and high priority customers or to respond to an emergency.

(7) Should customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such customer requirements.

<u>Applicability of Rules:</u>

Service under this Rider is subject to Company's rules and regulations governing the supply of gas service as incorporated in this Tariff, to the extent that such rules and regulations are not in conflict with nor inconsistent with the specific provisions hereof.

GAS SUPPLY CLAUSE
GSC

Applicable to:

All gas sold.

Gas Supply Cost Component (GSCC): (PGA) 8924-R)

Gas Supply Cost	27.043¢
Gas Cost Actual Adjustment (GCAA)	0.241
Gas Cost Balance Adjustment (GCBA)	(0.269)

Refund Factors (RF) continuing for 12 months from the effective date of each or until Company has discharged its refund obligation thereunder:

Refund Factor Effective August 1, 1987 from 8924-O	(0.020)	
Refund Factor Effective November 1, 1987 from 8924-P	(0.013)	
Total of Refund Factors Per 100 Cubic Feet		(0.033)
Total Gas Supply Cost Component Per		26.982¢

The monthly amount computed under each of the rate schedules tp which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each 3-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each 3-month period determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected total purchases at the filed rates of Company's wholesale supplier of natural gas, plus

(b) Other gas purchases for system supply, minus

(c) Portion of such purchase cost expected to be used for non-Gas Department purposes, minus

(d) Portion of such purchase cost expected to be injected into underground storage, plus

(e) Expected underground storage withdrawals at the average unit cost of working gas contained therein.

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous quarter's expected gas cost and the actual cost of gas during that quarter.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 12 of this Tariff.

Company shall file a revised Gas Supply Cost Component (GSCC) every 3 months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. Such filing shall be made at least 30 days prior to the beginning of each 3-month period and shall include the following information:

(1) A copy of the tariff rate of Company's wholesale gas supplier applicable to such 3-month period.

(2) A statement, through the most recent 3-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.

(3) A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such 3-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each 3-month period.

In the event that the Company receives from its supplier a refund of amounts paid to such supplier with respect to a prior period, the Company will make adjustments in the amounts charged to its customers under this provision, as follows:

(1) The "Refundable Amount" shall be the amount received by the Company as a refund less any portion thereof applicable to gas purchased for electric energy production. Such refundable amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the 12-month period which commences with implementation of the next gas supply clause filing, thus determining a "Refund Factor."

(2) Effective with the implementation of the next Gas Supply Clause filing, the Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be

applicable during the subsequent 12-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the refundable amount.

(3) In the event of any large or unusual refunds, the Company may apply to the Public Service Commission for the right to depart from the refund procedure herein set forth.

GENERAL RULES

Charges for Disconnecting and Reconnecting Service:

23. A charge of $14.00 will made to cover disconnection and reconnection of gas service when discontinued for non-payment of bills or for violation of the Company's rules and regulations, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

Customers under General Gas Rate G-1 may request and be granted a temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $14.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of Adjustment
for
Group Life Insurance

	Amount	Insurance Coverage		Rate	Month	Total Amount
Union Employees:						
A. For first $5,000 of Coverage						
2,459 employees X $5,000	$12,295,000	100%	$12,295,000	.59/1000	12	$ 87,048
B. For additional coverage						
Wages & Salaries	74,634,771	125	93,293,464			
Increase in Salaries - 4%	2,985,390	125	3,731,738			
			97,025,202			
LESS: First $5,000			12,295,200			
			$84,730,002	.44/1000	12	447,372
Union Subtotal						$534,420
Nonunion Employees:						
A. For first $5,000 of Coverage						
1,242 employees X $5,000	6,210,000	100	6,210,000	.59/1000	12	43,968
B. For additional coverage						
Wages & Salaries	39,545,720	125	49,432,150			
Increase in Salaries	275,825	125	344,781			
			$49,776,931			
LESS: First $5,000			6,210,000			
			$43,566,931	.44/1000	12	230,02
Nonunion Subtotal						$273,99
TOTAL						$808,41
Operating Portion @ 72%						582,06
LESS: Test Year Amount per Books						473,68
NET ADJUSTMENT						$108,38

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of
Federal and State Unemployment for
Test Year Ended August 31, 1987

	Federal Unemployment	State Unemployment
Total Employees as of 9/6/87	3,920	3,920
Base Wage	$ 7,000	$ 8,000
Wages Subject to Tax	$27,440,000	$31,360,000
Rate/KIUC Information Request No. 2	.8%	1.2%
Tax	$ 219,520	$ 376,320
Operating Percentage	72%	72%
	$ 158,054	$ 270,950
Operating Tax for Test Year Ended 8/31/87		
January-December 1986	149,039	298,447
January-August 1986	<145,554>	<291,919>
January-August 1987	145,655	242,849
TEST YEAR UNEMPLOYMENT	$ 149,140	$ 249,377
ADJUSTMENT	$ 8,914	$ 21,573
Electric - 77%	6,864	16,611
Gas - 23%	2,050	4,962
	$ 8,914	$ 21,573

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of
Year-End Volumes of Business
Expense Adjustment

Total Expenses		$255,400,862 [1]
Wages & Salaries:		
Test Year Actual		<66,332,568> [2]
		$189,068,294
Total Electric Operations Revenues		$476,397,820 [3]
Sales to Other Utilities		<1,877,587> [4]
		$474,520,233
Ratio =	$\frac{\$189,068,294}{474,520,233} = 39.84\%$	
Revenue Increase Per Adjustment		$ 3,627,565
		.3984
		$ 1,445,222
Net Adjustment:		
Revenues		$ 3,627,565
Expenses		4,445,222
		$ 2,182,343

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1 Hart Exhibit 6, page 3, lines 1-6; August 31, 1987 Monthly Report, page 19.

2 Response to the Commission Order dated November 12, 1987, Item No. 16(d), page 2.

3 Hart Prepared Testimony, Exhibit 1, Column 5.

4 *Ibid*.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE SALE AND DETARIFFING OF EMBEDDED CUSTOMER PREMISES EQUIPMENT PHASE 5 NETWORK CHANNEL TERMINATION EQUIPMENT	))))	ADMINISTRATIVE CASE NO. 269

O R D E R

Introduction

On April 18, 1988, the Commission issued an Order establishing Phase 5 of this case and ordered all Local Exchange Carriers ("LECs") to submit certain information regarding Network Channel Terminating Equipment[1] by May 18, 1988. This Order was issued in conjunction with the Federal Communications Commission ("FCC") Eighth Report and Order in CC Docket No. 81-893 released on January 29, 1988 which ordered detariffing of embedded digital Network Channel Terminating Equipment effective July 1, 1988. The disposition of analog Network Channel Terminating Equipment is being considered in FCC Docket No. 83-752 and is, therefore, not a part of this proceeding. All LECs responded to the Commission Order to submit information concerning Network Channel Terminating Equipment.

1 Network Channel Terminating Equipment is a generic term for interface devices located on customers premises to perform functions necessary for using a transmission channel for digital communications.

Discussion

In its response to the Commission's Order, Cincinnati Bell Telephone Company ("Cincinnati Bell") stated that in accordance with the Order in this case dated September 10, 1985, which ordered independent telephone companies to detariff and transfer to unregulated operations embedded customer premises equipment no later than December 31, 1987, it has detariffed all Network Channel Terminating Equipment in Kentucky.

GTE South Incorporated has also stated that all digital Network Channel Terminating Equipment had been detariffed and transferred to unregulated activities as of December 31, 1987 although GTE did not specifically state whether the transfer was interstate or intrastate investment.

South Central Bell Telephone Company in accordance with the Eighth Report and Order, plans to detariff digital Network Channel Terminating Equipment effective July 1, 1988.

The response of Alltel Kentucky, Inc. urged the Commission to differentiate between digital and analog Network Channel Terminating Equipment and to be consistent with the FCC which has allowed carriers to provide Network Channel Terminating Equipment that supports only loopback functions as a part of regulated basic services.

Finally, several of the small companies responded that the only investment they had similar in nature to that described by the Commission, was network channel terminating units associated with special access circuits. Based upon the descriptions provided by these companies, these network channel terminating units appear to be a part of basic network facilities and therefore would not be considered to be customer premises equipment.

FINDINGS AND ORDERS

The Commission, having considered the evidence of record and being advised is of the opinion that:

1. Effective no later than July 1, 1988 digital Network Channel Terminating Equipment should be detariffed by all LECs.

2. Analog Network Channel Terminating Equipment shall remain under tariff pending the outcome of the FCC investigation in CC Docket No. 83-752.

3. Loopback testing shall remain a tariffed service.

4. Network channel terminating units associated with the provision of special access which are analog in nature appear to be a part of basic network facilities and therefore would not be considered to be customer premise equipment.

IT IS THEREFORE ORDERED that:

1. All digital Network Channel Terminating Equipment CPE shall be detariffed and transferred to unregulated activities effective no later than July 1, 1988.

2. Loopback testing shall remain a tariffed service.

3. Network channel terminating units provided in connection with special access service which are analog in nature appear to be a part of basic network facilities and therefore would not be considered customer premise equipment and will remain under tariff pending a decision in FCC CC Docket No. 83-752.

4. All local exchange carriers shall file tariffs within 30 days of this Order reflecting the detariffing of Network Channel Terminating Equipment effective no later than July 1, 1988.

Done at Frankfort, Kentucky, this 1st day of July, 1988.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ATTEST:

Executive Director

EXHIBIT__(LK-PSC-13-2)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 90-158

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 90-158

O R D E R

On June 29, 1990, Louisville Gas and Electric Company ("LG&E") filed an application with the Commission requesting authority to increase its electric and gas rates for service rendered on and after August 1, 1990. The proposed rates would increase annual electric revenues by $31,015,938, an increase of 6.22 percent, and annual gas revenues by $3,837,454, an increase of 2.24 percent. These increases represent an annual increase in total operating revenues of $34,853,392, or 5.43 percent, based on normalized test-year sales. This Order grants an increase in annual electric revenues of $5,451,758, an increase of 1.17 percent, and an increase in annual gas revenues of $524,487, an increase of .30 percent. These increases represent an annual increase in total operating revenues of $5,976,245, or .93 percent, based on normalized test-year sales.

The Commission granted motions to intervene filed by the Attorney General, by and through his Utility and Rate Intervention Division ("AG"); Jefferson County ("Jefferson"); the city of Louisville ("Louisville"); the Department of Defense of the United States ("DOD"); the Kentucky Industrial Utility Customers

("KIUC"); the Paddlewheel Alliance ("Paddlewheel"); the Kentucky Cable Television Association, Inc. ("KCTA"); the Metro Human Needs Alliance, Inc., which assists low-income households ("MHNA"); the International Brotherhood of Electrical Workers, Local 2100; and Reynolds Metals Company. The Commission suspended the proposed rate increase through December 31, 1990 in order to conduct an investigation into the reasonableness of the proposed rates. A public hearing was held in the Commission's offices in Frankfort, Kentucky, on November 7-9, 19-21, and 26, 1990 with all parties of record represented. Simultaneous briefs were filed on December 14, 1990. All information requested during the hearing has been submitted.

COMMENTARY

LG&E is a privately owned electric and gas utility which generates, transmits, distributes, and sells electricity to approximately 321,300 consumers in Jefferson County and in portions of Bullitt, Hardin, Henry, Meade, Oldham, Shelby, Spencer, and Trimble counties. LG&E distributes and sells natural gas to approximately 243,400 consumers in Jefferson County and in portions of Barren, Bullitt, Green, Hardin, Hart, Henry, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Trimble, and Washington counties.

TEST PERIOD

LG&E proposed the 12-month period ending April 30, 1990 as the test period for determining the reasonableness of the proposed rates. LG&E also proposed to reflect the impact of the commercialization of the Trimble County Unit No. 1 ("Trimble

County") Generating Plant which was scheduled for late December 1990. Jefferson, Louisville, and Paddlewheel ("Jefferson et al.") and KIUC opposed this approach, stating that LG&E had created a hybrid test year which was neither fully historic nor fully projected. The Commission believes it is reasonable to utilize the 12-month period ending April 30, 1990 as the test period in this proceeding. In utilizing the historic test period, the Commission has given full consideration to appropriate known and measurable changes.

NET ORIGINAL COST RATE BASE

Trimble County

LG&E proposed a total company net original cost rate base of $1,444,036,873. Trimble County was reflected in rate base by including test year end Construction Work in Progress ("CWIP") of $677,170,687, plus estimated additional expenditures through December 31, 1990 of $37,829,317, less $178,750,000 to reflect the 25 percent disallowance for Trimble County ordered by the Commission in Case No. 9934.[1] LG&E also included in its proposed accumulated depreciation the first year depreciation expense on the December 31, 1990 estimated level of investment in Trimble County, exclusive of the 25 percent disallowance. LG&E cited two reasons for including Trimble County in the net original cost rate base. First, it stated that the Trimble County expenditures are known and measurable; and second, it claimed that the Settlement Agreement, Article IX, approved in Case No. 10320,[2] provide an

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[1] Case No. 9934, A Formal Review of the Current Status of Trimble County Unit No. 1, Order dated July 1, 1988.

absolute right to recover 75 percent of its Trimble County investment, including depreciation.

While the AG, Jefferson et al., and KIUC all filed testimony opposing LG&E's proposed treatment of Trimble County, none of these intervenors prepared a net original cost rate base. Their testimony focused on the impact that LG&E's proposals had on total capitalization, discussed later in this Order.

The Commission finds that the post test-year Trimble County expenditures are not known and measurable but, rather, are a moving target. On numerous occasions during the course of this case, LG&E revised its estimated December 31, 1990 level for Trimble County CWIP. In fact, LG&E's most recent revision discloses that almost $11,000,000 of Trimble County CWIP will not be spent until after January 1, 1991.

In proposing this rate base treatment for Trimble County, LG&E has ignored a basic concept of rate-making, the matching principle. While all rate base items except Trimble County are established at actual April 30, 1990 levels, LG&E has included a post test-year plant addition for Trimble County CWIP and the related accumulated depreciation at the estimated December 31, 1990 level. The Commission has a well-established, rate-making policy on the inclusion of post test-period plant additions. All utilities under the Commission's jurisdiction were given notice that, if a historic test period is used, adjustments for post

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2 Case No. 10320, An Investigation of Electric Rates of Louisville Gas and Electric Company to Implement a 25 Percent Disallowance of Trimble County Unit No. 1, Order dated October 2, 1989.

test-period plant additions should not be requested unless all revenues, expenses, rate base, and capital items have been updated to the same period as the plant additions.[3] LG&E acknowledged that it was aware of this policy but argued that it should not apply to this case because the policy was announced after the Settlement Agreement was signed on August 11, 1989.

The Commission is not persuaded by LG&E's argument. The date that the Settlement Agreement was signed has no particular significance in determining the applicability of the rate-making policy announced on August 22, 1989 in Case Nos. 10201[4] and 10481. The Settlement Agreement did not become binding and enforceable until approved by the Commission on October 2, 1989, six weeks after the Commission declared that:

> Therefore, in cases filed after this decision is issued, the Commission gives notice to Columbia [Kentucky-American] and other utilities under its jurisdiction that: 1) adjustments for post test-period additions to plant in service should not be requested unless all revenues, expenses, rate base, and capital items have been updated to the same period as the plant additions. . . .[5]

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3 Case No. 10481, Notice of Adjustment of the Rates of Kentucky-American Water Company Effective on February 2, 1989, Order dated August 22, 1989, page 5.

4 Case No. 10201, Adjustment of Rates of Columbia Gas of Kentucky, Inc., Order dated August 22, 1989.

5 Case No. 10201, Order dated August 22, 1989, page 6; and Case No. 10481, Order dated August 22, 1989, page 5.

This rate-making policy, having been announced before the Settlement Agreement was approved, and long before this rate case was filed, is applicable and controlling. Further, there is no language in the October 2, 1989 Order approving the Settlement Agreement that allows LG&E to disregard this policy.

Nevertheless, this Commission also recognizes that Trimble County represents a significant addition to LG&E's utility plant in service. By the date the rates authorized in this Order take effect, Trimble County will be in commercial operation and all Trimble County expenditures will be reclassified from CWIP to plant-in-service. Therefore, the Commission must consider the commercialization of a major plant addition and at the same time adhere to rate-making concepts, time tested for fairness and reasonableness.

We believe it fair and reasonable in this instance to include in LG&E's net original cost rate base the test-year-end Trimble County CWIP. This amount, net of the 25 percent disallowance, is $507,878,016. This rate-making treatment is essentially the same that LG&E has received throughout the construction of Trimble County. The Commission also finds it reasonable in this instance to allow depreciation expense on 75 percent of the Trimble County CWIP balance as of the end of the test year. The first year depreciation expense has been included in the accumulated depreciation used in determining the net original cost rate base. This approach properly recognizes the known and measurable fixed cost associated with the commercialization of Trimble County. The Commission cannot and will not include in rate base the post test-period plant additions for Trimble County or the related first year depreciation expense. To do otherwise would disregard established, and we feel fair, just and reasonable rate-making practices enunciated and adopted in prior Commission decisions concerning post test-period plant additions.

Fuel Inventory

LG&E proposed to include $14,297,235 as fuel inventory in its rate base calculations. This amount represents the test-year end balance for the fuel inventory account. During the hearing, LG&E indicated that it began to purchase coal for Trimble County in January 1990, but had not adjusted the fuel inventory to reflect a 25 percent disallowance of the Trimble County coal. The AG proposed to remove 25 percent of the increase in the fuel inventory between April 30, 1989 and April 30, 1990, stating the entire increase had to be related to Trimble County.

Based on a monthly account balance for fuel inventory review, the Commission believes it is more appropriate to use a 13-month average balance for fuel inventory in the calculation of rate base. The use of a 13-month average balance is consistent with our usual practice. The Commission also believes it is reasonable to remove from the fuel inventory 25 percent of the coal inventory related to Trimble County coal. The 13-month average balance for fuel inventory, including the Trimble County coal was $10,280,683.[6] The Commission has calculated a 13-month average balance, removing the Trimble County coal from each monthly

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6 Response to Commission's Order dated June 29, 1990, Item 9.

balance, and finds that $10,270,961 should be used in the calculation of rate base.

Materials, Supplies, and Prepayments

In determining its net original cost rate base, LG&E used the test-year end balances for materials, supplies, and prepayments. The AG proposed to remove 25 percent of the increase in materials and supplies between April 30, 1989 and April 30, 1990, stating the entire increase had to be related to Trimble County. The Commission has reviewed the monthly account balances for these accounts, and as discussed previously, believes it is more appropriate to use a 13-month average balance for these accounts in the calculation of rate base. The Commission also believes it is reasonable to remove from materials and supplies 25 percent of any amounts related to Trimble County. During the hearing, LG&E indicated that $1,945,000[7] was included in materials and supplies for Trimble County. The 13-month average balance for materials and supplies, including the Trimble County materials and supplies, was $32,691,260.[8] The Commission would prefer to adjust the Trimble County amounts out on a monthly basis, and then compute the 13-month average. In this instance, the detailed information

7 Transcript of Evidence ("T.E."), Volume IV, November 19, 1990, pages 181 and 182.

8 Response to Commission's Order dated June 25, 1990, Item 9.

is not available. Therefore, the Commission has deducted $486,250[9] from the $32,691,260 average, and included $32,205,010 in rate base for materials and supplies. We included $748,304[10] for prepayments in our calculation of rate base.

Stores Expense

The AG also proposed to remove 25 percent of the increase in stores expense between April 30, 1989 and April 30, 1990, for the same reason stated in his adjustment to materials and supplies. At the hearing, LG&E stated that $434,000 in stores expense was related to Trimble County.[11] The Commission believes it is appropriate to remove 25 percent of its Trimble County stores expense from the rate base calculations. The test-year-end balance of $5,790,584 has been reduced by $108,500[12] to reflect the removal of the 25 percent Trimble County stores expense.

Gas Stored Underground

LG&E proposed to include $20,450,243 as gas stored underground in its calculation of rate base. This amount represented a 12-month average balance of the gas stored underground account. Again we believe it is more reasonable to use the 13-month average balance, and have included $19,515,080 as gas stored underground in the calculation of rate base.

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9 $1,945,000 x 25 percent = $486,250.

10 Response to Commission's Order dated June 29, 1990, Item 9.

11 T.E., Volume IV, November 19, 1990, pages 181 and 182.

12 $434,000 x 25 percent = $108,500.

Cash Working Capital Allowance

LG&E determined its cash working capital allowance using the 45 day or 1/8 formula methodology. This Commission has traditionally used this approach in rate cases and do again here. We have adjusted the allowance for cash working capital to reflect the accepted pro forma adjustments to operation and maintenance expenses.

In determining the cash working capital allowance, LG&E deducted from the operation and maintenance expenses the gas supply expenses. The level of gas supply expenses removed did not equal the amount LG&E deducted in its operating expense adjustment for gas supply expenses. It is best to use the same amount in both adjustments. Therefore, we have used the operating expense adjustment level of gas supply expenses in the calculation of the cash working capital allowance.

Based upon the previous findings, we have determined the net original cost rate base for LG&E at April 30, 1990 to be as follows:

	Electric	Gas	Total
Total Utility Plant	$1,915,177,722	$221,751,683	$2,136,929,405
Add:			
Materials & Supplies	46,804,173	1,353,882	48,158,055
Gas Stored Underground	0	19,515,080	19,515,080
Prepayments	621,092	127,212	748,304
Cash Working Capital	32,815,128	4,441,938	37,257,066
Subtotal	$ 80,240,393	$ 25,438,112	$ 105,678,505
Deduct:			
Reserve for Depreciation	529,783,546	84,484,852	614,268,398
Customer Advances	1,572,719	5,134,306	6,707,025
Accumulated Deferred Taxes	193,385,140	19,093,760	212,478,900
Investment Tax Credit (Prior Law)	1,127,320	427,400	1,554,720
Subtotal	$ 725,868,725	$109,140,318	$ 835,009,043
NET ORIGINAL COST RATE BASE	$1,269,549,390	$138,049,477	$1,407,598,867

Reproduction Cost Rate Base

LG&E presented a reproduction cost rate base of $2,605,266,805,[13] which included electric facilities of $2,238,145,899 and gas facilities of $367,120,906. LG&E estimated the value of plant in service, plant held for future use, and CWIP at the end of the test year. LG&E also reflected the same adjustments it had included in its net original cost rate base. We have given consideration to the proposed reproduction cost rate base.

CAPITAL

LG&E proposed a total capitalization of $1,384,481,820.[14] Included in the total capitalization were five adjustments, which

[13] Fowler Direct Testimony, Exhibit 5.

[14] Fowler Direct Testimony, Exhibit 2, page 1 of 2.

LG&E allocated on a pro rata basis to all components of capital. The five adjustments were for the Job Development Investment Tax Credit ("JDIC"), the 25 percent disallowance of test year Trimble County CWIP, the unamortized balance of extraordinary retirements as determined by the Commission in Case No. 10064,[15] the estimated additional expenditures for Trimble County through December 31, 1990 net of the 25 percent disallowance, and the capital costs relating to LG&E's new office building.

The AG proposed a total capitalization of $1,352,739,019.[16] The AG added to total debt capital the difference between the 12-month average balance of gas stored underground and the April 30, 1990 balance. The AG deducted from common equity the entire 25 percent disallowance of test-year Trimble County CWIP and 25 percent of the net increase in fuel and supplies increases. After making these adjustments, the AG allocated on an adjusted pro rata basis the JDIC, the unamortized balance of extraordinary retirements, and the capital costs relating to LG&E's new office building. The AG stated that the adjustment to debt capital was necessary because the test-year end balance was not representative of the 12-month average balance, and it was logical to assume that the gas balances were financed by short-term debt since they varied greatly during the test year. The AG's proposal to remove

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15 Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, Order dated July 1, 1988.

16 DeWard Direct Testimony, Exhibit TCD-1, Schedule 3.

the 25 percent Trimble County CWIP disallowance totally from common equity was based on the Settlement Agreement approved in Case No. 10320, which assigned any benefits, profits, or entitlements realized on the disallowed 25 percent of Trimble County to the shareholders of LG&E. The AG stated that LG&E had put itself at risk for both the costs and rewards related to the 25 percent disallowance. MHNA supported the AG's position on this issue.[17] The AG stated that it was logical that LG&E would begin to increase levels of fuel and supplies for Trimble County and that 25 percent of those increases should also be removed.

KIUC proposed a total capitalization of $1,356,100,000.[18] KIUC began with LG&E's total proposed capitalization and removed the pro rata allocation of the estimated additional expenditures for Trimble County through December 31, 1990. KIUC stated that LG&E had created a hybrid historic and forecasted test year, inconsistently relying upon actual historic costs in some instances and totally forecasted costs in other instances.[19]

Jefferson et al. did not propose an amount for total capitalization, but took issue with LG&E's proposal to include the estimated additional expenditures for Trimble County through December 31, 1990. Jefferson et al. stated that LG&E's application had to be evaluated using the historic test year

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17 Brief of MHNA, pages 7 and 8.

18 Kollen Direct Testimony, Table 6, page 42.

19 Id., page 13.

approach, and these additional expenditures did not constitute known and measurable items.

The Commission does not agree that an adjustment to the capitalization is necessitated by the use of an average balance for gas stored underground in the rate base determination. Nor do we agree with the argument that LG&E finances its gas stored underground exclusively through debt capital. In determining the capitalization of a utility, the Commission establishes the overall embedded capital needs which includes working capital items which vary in value throughout the course of a 12-month test period. These variations are sufficient to compensate LG&E for the monthly variations in gas stored underground. Such an adjustment is not necessary in this case.

Concerning the AG's proposal to remove the entire 25 percent disallowance of Trimble County CWIP from common equity, the Commission has ruled in prior cases that the investment in utility plant cannot be traced to specific capital sources. The AG presented no evidence to demonstrate that this investment actually came from common equity alone. Trimble County's construction has been financed by all components of capital, not solely by common equity. It is reasonable to allocate the disallowance on a pro rata basis, in order to reflect this fact. The Commission notes the inconsistency of the AG's position on this adjustment. While proposing a higher level of debt for capitalization, this higher level of debt was not reflected in the AG's proposed rate of return.

The Commission has determined that LG&E's total test-year end capitalization should be $1,355,523,360. The Commission has accepted all of LG&E's proposed adjustments to capitalization with the exception of the estimated additional expenditures on Trimble County through December 31, 1990. As has been discussed earlier in this Order, the Commission has determined that it is not reasonable nor equitable to include these estimated expenditures in rate base without concurrent adjustments to revenues and expenses. Likewise, capitalization must reflect only the level of Trimble County expenditures as of test-year end. The Commission has also adjusted the capitalization for the amount removed from rate base relating to the Trimble County coal inventory, materials and supplies, and stores expense.

PROPOSED PHASE II PROCEEDING

LG&E proposed a "Phase II" proceeding in addition to the current rate case. As proposed, Phase II would establish a process whereby LG&E could recover the allowable 75 percent portion of operation and maintenance expenses associated with the operation of Trimble County. Four areas would be addressed in Phase II. LG&E proposed to file with the Commission calculations annualizing the first three months of actual operating and maintenance expenses at Trimble County, as adjusted for unrepresentative costs. Operating expenses would be reduced by any Trimble County labor expenses recovered in this proceeding. Operating and maintenance expenses would also be reduced by 25 percent of the administrative and general expenses associated with the operation of Trimble County. Additional adjustments would be made to reduce the operating and maintenance expenses by the net revenues realized from off-system sales attributable to the allowable 75 percent portion of Trimble County and depreciation on Cane Run Unit No. 3, if the unit has been retired.[20] LG&E offered this process as a means to avoid the expenses and time associated with additional rate case proceedings, reduce the effects of regulatory lag, avoid the problems associated with a forecasted test year proceeding, and benefit LG&E's customers by allowing it to avoid future rate filings for a period of time.[21]

The AG, KIUC, and Jefferson et al. are opposed to the Phase II proposal. The AG questioned LG&E's willingness to provide information necessary to evaluate such a filing and how representative three months of operational data and off-system sales would be on a going forward basis.[22] KIUC characterized it as an attempt to inappropriately accelerate its Trimble County cost recovery and that the plan was premature and poorly designed.[23] Jefferson et al. cited problems with the three months chosen for annualization, the complexity of calculating the annualization, and how known and measurable the final results would be.[24]DOD stated that the proposal was too narrow in scope.[25]

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20 Fowler Direct Testimony, page 31.

21 Id., page 3.

22 DeWard Direct Testimony, pages 53 and 54.

23 Kollen Direct Testimony, pages 5 and 22.

24 Kinloch Direct Testimony, pages 15 and 16.

25 Brief of DOD, page 11.

The Commission does not believe it is reasonable to accept the Phase II proposal. The abbreviated proceeding would make it difficult to properly match revenues, expenses, rate base, and capital items. Significant non-Trimble County events would be excluded from Phase II. There is insufficient evidence to demonstrate that an annualization of three months of actual Trimble County data would be representative of going forward conditions.

REVENUES AND EXPENSES

For the test period, LG&E had actual net operating income of $121,674,031.[26] LG&E originally proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions which resulted in an adjusted net operating income of $122,043,734.[27] Subsequently, LG&E proposed several correcting adjustments. The proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications.

Revenue Normalization - Electric

LG&E proposed normalized electric operating revenues of $502,388,879 based on the rates in effect at the end of the test year. In normalizing its electric revenues, LG&E made adjustments to reflect year-end customers, to eliminate a non-recurring refund, and to eliminate the effect of changing to the unbilled method of recording revenues midway through the test year.

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26 Fowler Direct Testimony, Exhibit 1, page 1 of 3.

27 Id., page 3 of 3.

KIUC proposed an adjustment to increase normalized electric revenues by $4,896,459 to recognize for rate-making purposes the initial booking of unbilled revenues reported by LG&E in January 1990. The adjustment proposed by KIUC reflects a 3-year amortization of LG&E's initial booked amount of $14,689,378. KIUC contends that a one-time event such as LG&E's initial booking of unbilled revenues should be given rate-making treatment consistent with that afforded the one-time downsizing for which LG&E proposed a 3-year amortization. KIUC maintains that both the downsizing costs and the initial booking of unbilled revenues should either be amortized and included in the determination of LG&E's revenue requirements or treated as one-time, non-recurring events that were booked during the test year, will not impact future earnings, and should be excluded from the determination of LG&E's revenue requirements.

LG&E's proposed adjustments are reasonable for determining normalized electric revenues. No adjustment should be made to amortize the amounts included in LG&E's initial booking of unbilled revenues. The initial booking is a one-time occurrence recorded during the test year that will not impact future periods during which the approved rates will be in effect.

<u>Revenue Normalization - Gas</u>

LG&E proposed normalized gas operating revenues of $194,585,467 based on the rates in effect at the time of filing its application. In normalizing its gas revenues, LG&E made adjustments to reflect normal weather conditions and year-end customers. LG&E eliminated the effect of changing to the unbilled method of recording revenues and adjusted its gas cost revenues to $130,285,428 based on its wholesale gas cost in effect at the time the application was filed.

KIUC proposed an adjustment to increase LG&E's normalized gas revenues by $5,034,036 to reflect a 3-year amortization of LG&E's initial booking of unbilled revenues. This was the same adjustment KIUC proposed for LG&E's electric revenues. For the same reasons previously cited in the discussion of electric revenues, the Commission finds that no adjustment should be made.

LG&E's normalized gas operating revenues have been reduced by $11,289,435 to $183,296,032 based on LG&E's latest gas cost adjustment effective November 1, 1990.[28] This includes gas cost revenues of $118,995,993 based on LG&E's current cost of gas. LG&E's purchased gas expense has also been reduced to this amount to reflect the current gas cost adjustment. With this adjustment, LG&E's gas operating revenues will be properly normalized for rate-making purposes.

Fuel Cost Recovery

On an adjusted basis, LG&E's electric fuel cost exceeded its fuel cost recovery by $1,737,240 during the test year. The AG proposed an adjustment to reduce fuel expense by $1,737,240 in order to match fuel cost and fuel cost recovery to ensure that the test-year under-recovery of fuel costs did not impact the setting of base rates in a non-fuel cost rate proceeding.

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28 Case No. 10064-J, The Notice of Purchased Gas Adjustment Filing of Louisville Gas and Electric Company, Order dated November 1, 1990.

LG&E maintains that the AG's adjustment was based on an erroneous understanding of the fuel adjustment clause ("FAC"). LG&E contends that the timing difference that exists between the incurrence of fuel costs and the recovery of fuel costs prohibits a matching of fuel cost and fuel revenues in any 12-month period. LG&E recounts that these types of adjustments have not been made in its past rate cases because the FAC was not designed to match revenues with expenses but was designed to track a variable cost outside of a general rate proceeding.

LG&E opines that the over- and under-recovery mechanism approved in Administrative Case No. 309[29] will improve the match between fuel cost and fuel revenues but will not provide for a full reconciliation of costs and that the proposed adjustment would deprive LG&E of the opportunity to fully recover its costs.

It is true that the current FAC does not produce an absolute synchronization of fuel costs and fuel cost recovery. Nor does it result in a full reconciliation of costs that will produce a precise matching of fuel costs and fuel revenues in any 12-month reporting period. The current FAC, however, with the over- and under-recovery mechanism approved in Administrative Case No. 309 is fully recovering, meaning that all allowable fuel costs will, over time, be recovered through the clause.

In the past, the FAC tracked fuel costs for one month in order to determine an adjustment factor that would be applied to a

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29 Administrative Case No. 309, An Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056, Order dated December 18, 1989 and Order dated April 16, 1990.

subsequent month's kilowatt-hour sales. This factor, applied with a 2-month lag to a different level of sales, would produce an over- or under-recovery for the billing month that was not tracked, or reconciled, in subsequent months. Once incurred, a monthly over- or under-recovery was lost, either to the utility or the ratepayer, and was not subject to true-up at a later date.

The over- and under-recovery mechanism now in place ensures that a given month's over- or under-recovery will be tracked and included in the utility's fuel cost calculation in a later month. The result is a fully recovering FAC through which all allowable fuel costs will, over time, be recovered. With recovery of fuel costs through the FAC assured, it is improper to include the over- or under-recovery of a given test year in the determination of a utility's revenue requirements. Therefore, an adjustment should be made to eliminate LG&E's test-year under-recovery of $1,737,240.

Labor and Labor-Related Costs

LG&E proposed adjustments to increase the test-year operating expenses by $3,570,447 for labor and labor-related costs. The actual cost items and the proposed adjustments to combined gas and electric operations are as follows:

	Total
Wages and Salaries	$4,010,669
FICA Taxes	334,829
Federal Unemployment	21,262
State Unemployment	41,348
Health Insurance	(636,899)
Pensions	(462,358)
Dental Insurance	29,463
Group Life Insurance	232,133
	$3,570,447

Wages and Salaries. LG&E proposed to increase wages and salaries by $4,010,669. The proposed increase reflected the effects of base wage increases granted to non-union employees during the test year, a lump sum transition payment to non-union employees during the test year, a 3 percent wage increase for union employees effective November 12, 1990, and a change in the labor capitalization rate due to the future commercialization of Trimble County. LG&E's adjustment included the annualization of the actual test-year-end levels of wages for each employee group. The November wage increase was applicable to all of LG&E's union employees, including those identified as "project temporaries" who work at Trimble County. Instead of using its test-year actual labor capitalization rate, LG&E used the capitalization rate for the month of April 1990 and adjusted it to reflect the changes expected in labor operating expenses due to the commercialization of Trimble County. This adjusted labor capitalization rate was included in all of LG&E's labor and labor-related cost adjustments.

The AG disagreed with three components of LG&E's proposed adjustment: (1) allowing the 3 percent union wage increase for the project temporaries, citing LG&E's statements that these employees would no longer be employed once Trimble County was in commercial operation; (2) the inclusion of the lump sum transition payment to non-union employees, stating that future incentive payments were not known and measurable and not appropriate for inclusion; and (3) the use of the adjusted April 1990 capitalization rate, inasmuch as LG&E had not established that

April was a representative month and that LG&E was attempting to recover Trimble County costs without making necessary adjustments to off-system sales and expenses.

KIUC recommended that all non-Trimble County pre- and post-test-year adjustments proposed by LG&E be rejected as inconsistent with the basic underlying concepts of determining the test year basis for fair, just, and reasonable rates.[30] KIUC included the November 1990 union wage increase in this group of adjustments. KIUC further argued that all pro forma adjustments proposed by LG&E be rejected in the absence of a complete set of appropriate pro forma adjustments to non-Trimble County operating income and rate base.[31]

LG&E's proposed adjustment to wages and salaries is reasonable, except for two issues. While the November union wage increase is based on the union contract, the Commission does not believe it is appropriate to allow the 3 percent increase for the Trimble County project temporaries. This particular group of employees will be terminated once Trimble County is completed.[32] The use of the adjusted April 1990 labor capitalization rate proposed by LG&E is not acceptable. The adjustment of the rate to reflect what is expected to happen when Trimble County is commercialized is not appropriate. In light of the Commission's decision to include only the level of investment in Trimble County

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30 Kollen Direct Testimony, page 25.

31 Id., page 29.

32 T.E., Volume IV, November 19, 1990, page 268 and 269.

as of test-year end, it is not appropriate to use the estimated labor capitalization rate. However, we have used the actual labor capitalization rate for the last month of the test year, April 1990, without the Trimble County adjustment. The April 1990 labor capitalization rate was 32.09 percent[33] which reduces LG&E's test-year wages and salaries by $475,505.

FICA Taxes. LG&E proposed to increase its FICA taxes to reflect increases in total wages and salaries, a change in the FICA taxable wage base, and a change in the FICA tax rate. The Commission has reviewed LG&E's calculations for the FICA taxes. It appears that LG&E did not include in its calculations the effects of the November 1990 union wage increase. Wage adjustments and payroll tax adjustments should be determined in a consistent manner and reflect the same wage increases. Based on the Commission's decisions concerning the wage and salary adjustment, the FICA taxes have been recalculated which increases LG&E's test-year FICA taxes by $133,583.

Unemployment Taxes. In calculating its proposed increase to federal and state unemployment taxes, LG&E followed the methodology outlined by the Commission in Case No. 10064. The proposed adjustment is reasonable, except for the labor capitalization rate. Using the actual April 1990 labor

33 Response to the Commission's Order dated June 29, 1990, Item 16(d), page 7 of 16, $3,314,676 / $10,330,308 = 32.09 percent.

capitalization rate, federal unemployment insurance should be increased $14,701 and state unemployment insurance should be increased $33,850 over the test-year actual expense.

Health Insurance. LG&E's proposed reduction in health insurance costs reflected its efforts in controlling its medical benefit costs, which had been an issue in LG&E's last two general rate cases. The AG opposed the use of the adjusted April 1990 labor capitalization rate in the calculation of this adjustment. Using the actual April 1990 labor capitalization rate, it is reasonable to reduce the test-year health insurance expense by $1,003,962.

Pensions. LG&E's proposed pension expense adjustment included the results of its latest actuarial study. The AG disagreed with incorporating the results of this study in the adjustment, stating that a change in wage assumptions was not an appropriate reason to ask ratepayers to bear the additional expense. The AG also opposed the use of the adjusted labor capitalization rate. Except for the labor capitalization rate utilized, the pension adjustment is reasonable, resulting in a $566,651 decrease in test-year pension expense.

Dental Insurance. The AG again opposed the use of the adjusted labor capitalization rate in determining the adjustment to dental insurance. The Commission believes that the dental insurance expense is reasonable, except for the labor capitalization rate utilized, and has determined the test-year dental insurance expense should be decreased by $7,909.

Group Life Insurance. In determining its proposed increase to group life insurance expense, LG&E followed the methodology outlined by the Commission in Case No. 10064. Included in the calculations were the total November 1990 union wage increase and the adjusted April 1990 labor capitalization rate. For the same reasons stated concerning the wage and salary adjustment, the AG opposed the inclusion of the union wage increase for the Trimble County project temporaries and the adjusted labor capitalization rate. In accordance with our decision on the wage and salary adjustment, we have excluded the union wage increase for the project temporaries and utilized the actual April 1990 labor capitalization rate in making this adjustment, which increases the test-year group life insurance expense by $206,187.

401(k) Thrift Savings Plan. Included in LG&E's test year expenses for labor-related costs was the employer's share of its 401(k) thrift savings plan ("401(k) plan"), which totalled $449,029. This amount represented LG&E's match to amounts deferred by its non-union employees who participated in the 401(k) plan. LG&E proposed no adjustment to the test-year expense. LG&E noted that the 401(k) plan was available only to non-union employees, and very little of the matching share amount would be appropriate to capitalize.[34]

The AG proposed to reduce the test-year expense to reflect the capitalization of the expense at the test-year actual labor

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[34] T.E., Volume IV, November 19, 1990, pages 304 and 305.

capitalization rate, and that it was inappropriate to totally expense this item.[35]

The Commission's initial concern that LG&E had not adjusted the test-year expense to reflect the effects of its corporate reorganization, which occurred during the test year, was allayed by LG&E's schedule which showed the annualized test-year-end employer match to be $385,349.[36] We find it reasonable to include $385,349 in expenses for the 401(k) plan, which generates a reduction of $63,680 in test-year expense.

Supplemental Executive Retirement Plan. The AG proposed an adjustment removing the test-year expense of LG&E's Supplemental Executive Retirement Plan ("SERP"). The AG stated that the SERP was designated for certain key employees, and in light of the overall compensation and fringe benefits available to those employees, the costs of the SERP should not be borne by ratepayers. We agree, which reduces expenses by $247,922.

The Commission has noted in this proceeding several references by LG&E to its analysis and outside evaluations of portions of its labor and labor-related costs. In past orders the Commission has encouraged this type of evaluation, as did the management audit in several recommendations. However, LG&E has not yet performed an overall, comprehensive evaluation of its total compensation and fringe benefits package. Such an

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35 DeWard Direct Testimony, page 31.

36 Responses to Data Requests from Hearing, filed December 5, 1990, Item 18.

evaluation would compare LG&E's total compensation and fringe benefits package with other utilities as well as with other industries in its general service area. LG&E should undertake such an analysis of its total compensation and fringe benefits package as soon as possible.

Amortization of Downsizing Costs

During the last quarter of 1989, LG&E undertook a corporate reorganization which resulted in a workforce reduction of 174 exempt and non-exempt employees. Throughout this proceeding, this corporate reorganization has been referred to as a "downsizing." The costs associated with this downsizing totalled $9,486,550 and were composed of separation allowance payments, enhanced early retirement benefits, post-retirement health care provisions, and a gain on the purchase of retired employees' annuities.[37] LG&E proposed to amortize these costs over a 3-year period, and pointed out that the annual amortization would not exceed the expected annual savings resulting from the downsizing.[38]

The AG stated that LG&E had incurred or accrued these costs during the test year, had expensed these items during the test year, that these costs would not be occurring on a going forward basis,[39] and recommended removing the test-year downsizing costs in total and not allow amortization.

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37 Fowler Direct Testimony, page 18.

38 Id., page 19.

39 DeWard Direct Testimony, pages 28 and 29.

KIUC recommended that the downsizing costs be amortized over a 10-year period linked to the Commission's acceptance of KIUC's proposals concerning unbilled revenues. KIUC stated that if its proposals concerning unbilled revenues was not accepted, the Commission should disallow recovery of the downsizing costs as a matter of consistency.[40]

LG&E incurred and recorded the downsizing costs in the test year. LG&E has already recovered these costs from its ratepayers. While adjustments in its workforce will occur, it is highly unlikely that LG&E will be involved with a downsizing of this magnitude on a recurring basis. We have removed the entire $9,486,550 of downsizing costs for rate-making purposes.

Storm Damage Expenses

LG&E proposed an adjustment to increase storm damage expenses by $723,291. LG&E calculated its adjustment by averaging the actual storm damage expenses for the last 5 calendar years and comparing the average to the test-year actual expense. The methodology was essentially the same as was used by the Commission in Case No. 10064.

Jefferson et al. performed an analysis of LG&E's storm damage expenses for the past 15 years and determined that the test-year expense level was not below normal. Jefferson et al. arrived at the same conclusion using the 5-year period LG&E used but substituting two abnormal years with two normal years of expenses.

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40 Kollen Direct Testimony, page 25.

As the Commission noted in Case No. 10064, the random occurrence of severe storm damage cannot be accurately predicted. The Commission finds it is appropriate to include for rate-making purposes a level of storm damage expense which reflects a reasonable, on-going level of expense. Traditionally, the Commission has used historic averages in determining this reasonable level of expense. In this proceeding, the Commission has available the actual storm damage expenses for the past 15 calendar years. However, simply taking the average of an historic period would not recognize the effects of inflation when looking at such a long period of time. In Case No. 90-041[41] the Commission computed storm damage expenses by taking a 10-year average of actual expenses, adjusted for inflation by using the Consumer Price Index - Urban. We feel this approach the more reasonable and the preferred methodology to be used in determining this adjustment, which results in a $520,533 increase in storm damage expenses.

Provision for Uncollectible Accounts

LG&E proposed an increase of $100,000 to the test-year level of uncollectible accounts expense based on its analysis of the appropriate total annual provision. The proposed increase was determined using LG&E's actual 1990 accrual rate for the provision.

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41 Case No. 90-041, An Adjustment of Gas and Electric Rates of the Union Light, Heat and Power Company, Order dated October 2, 1990.

Jefferson et al. opposed the increase to the expense, citing the fact that LG&E's actual charge-off history and accruals for uncollectible accounts over the past 5 years have experienced significant decreases in overall percentage.

The Commission believes it is best to leave the uncollectible accounts expense at the test-year level.

Location of Gas Service Lines

LG&E proposed an increase of $152,000 in expenses related to the location of customer owned service lines on private property. LG&E stated that this adjustment reflects the additional costs that it expects to incur as a result of placing temporary markings to locate customer service lines.[42] The Commission finds that LG&E has not adequately explained or supported the necessity for this proposed adjustment. Therefore, the Commission has not included the proposed increase in expense. The Commission is not attempting to limit this activity. However, in determining the reasonable level of expense on an on-going basis, consideration must be given to whether the activity involves an item which should be expensed or capitalized. LG&E did not provide specific evidence to allow a thorough analysis of this issue.

Headwater Benefit Assessment

LG&E proposed an increase of $108,033 in expenses to reflect the first year of a 3-year amortization of its Federal Energy Regulatory Commission ("FERC") headwater benefit assessment. The total amount of $324,098 reflects LG&E's initial FERC payment

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42 Fowler Direct Testimony, page 21.

pending LG&E challenges to FERC's original assessment of $3,600,000. LG&E recorded this payment as a deferred debit.

KIUC claimed that LG&E had no regulatory authority to defer this cost for future recovery. KIUC further stated that LG&E selectively identified this cost as recoverable since it was not specifically identified as an expense in its last rate case. Under established rate-making theory, LG&E must bear the risks and rewards of such costs as long as specific regulatory authority for differing treatment is absent. KIUC argues that by allowing this adjustment, the Commission would establish a precedential basis for future manipulation of actual earnings and improper increases in revenue requirements in future rate cases.

Given that LG&E has not heretofore recovered this payment from its ratepayers, we find it reasonable to allow LG&E to amortize the headwater benefit assessment over a 3-year period.

Depreciation and Amortization Expense

LG&E proposed to increase depreciation expense by $15,333,843 in order to annualize the test-year-end level of expense and to reflect the first year of depreciation expense on Trimble County. Of the total adjustment, $15,171,389 was for electric and $162,454 was for gas. Included in the annualization calculations were the effects of LG&E's recently completed depreciation studies of the electric and gas plant in service. The increase in the electric depreciation reflected first year depreciation expense based on estimated total cost of $715,000,000 adjusted for the 25 percent disallowance.

The AG, KIUC, and Jefferson et al. all opposed this inclusion stating that LG&E wanted to treat Trimble County in a vacuum,[43] that LG&E's proposed treatment lacked consistency,[44] and that LG&E's adjustment for Trimble County expenses did not meet the known and measurable standard.[45]

Although the first year depreciation expense based on the CWIP as of April 30, 1990 is allowed, supra, we do not include any depreciation expense on the additional expenditures incurred after test-year-end. This allowance, together with other components of LG&E's proposed adjustment we find reasonable and should be included in expenses, which results in increased depreciation and amortization expenses of $14,431,836, $14,269,382 electric and $162,454 gas.

Property Taxes

LG&E proposed to increase its property tax expense by $982,754 based on the 75 percent recoverable portion of the total expected expenditures for Trimble County estimated at $715,000,000.

The AG, KIUC, and Jefferson et al. opposed the proposed adjustment for the same reasons they expressed concerning the Trimble County depreciation adjustment.

Consistent with our other decisions relating to Trimble County, we have included a portion of the fixed costs of Trimble

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43 DeWard Direct Testimony, page 48.

44 Kollen Direct Testimony, page 19.

45 Kinloch Direct Testimony, page 11.

County to allow an increase in property taxes related to the balance of Trimble County CWIP as of April 30, 1990, which increases the test-year property tax expense by $931,857.[46]

EPRI Membership Dues

LG&E proposed an increase of $1,311,826 to expenses representing the projected 3-year average of the annual membership dues LG&E will pay the Electric Power Research Institute ("EPRI"). In order for LG&E to access the research and development programs and materials produced by EPRI, LG&E became a member of EPRI in July 1990. LG&E's evidence showed that the annual costs of its membership in EPRI would be offset by the benefits it receives from EPRI. The full membership dues are phased-in over a 3-year period, and LG&E's proposed adjustment reflects the average of those first 3 years' dues as calculated for 1990.

The AG opposed the proposed adjustment because LG&E had not quantified any cost savings attributable to its membership in EPRI. KIUC opposed the adjustment because LG&E had not proposed all appropriate pro forma adjustments. Jefferson et al. recommended the Commission withhold ratepayer support of EPRI until EPRI's restrictive membership policy is changed or, at a minimum, the Commission should exclude that portion of EPRI's dues relating to nuclear research.

LG&E should have quantified expected cost savings and included those offsetting savings. The payment of the membership dues was clearly a post-test year transaction and the benefits

[46] Fowler Direct Testimony, Exhibit 1, Schedule E, line 3.

will likewise be reflected in reductions of future costs. In order to properly include the dues in this case, the cost savings expected from membership should have also been included. Because these expected savings were not shown, we feel compelled to exclude this proposed increase in expenses. The Commission realizes that utilities need to undertake research and development projects, and we are not opposed to including the costs of those projects when they are determined to be reasonable and benefits are demonstrated and factored into the proposed revenues and expenses.

EEI Membership Dues

During the test year, LG&E recorded as operating expense membership dues of $178,779 to the Edison Electric Institute ("EEI"). In Case No. 10064, the Commission excluded the membership dues to EEI because LG&E had failed to show that its membership in EEI was of direct benefit to its ratepayers.[47] The AG proposed to reduce the test year expense for various EEI-related activities it considered inappropriate. Jefferson et al. proposed that all EEI dues be removed from the test year because EEI was a utility industry lobbying organization. Although LG&E gave three examples of ratepayer benefits derived from its membership in EEI, it still has not adequately shown that there is a direct ratepayer benefit from membership in EEI. As LG&E acknowledged, all of the major benefits associated with EEI

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[47] Case No. 10064, final Order dated July 1, 1988, page 60.

membership are available to LG&E independent of EEI. Further, EEI's lobbying activities are clearly a below-the-line expense.

New Office Expenses

In keeping with LG&E's position to exclude all costs associated with the relocation to the new corporate headquarters, an additional $2,489[48] in legal costs related to the headquarters relocation which were inadvertently included in the test year have been excluded.

Holding Company Expenses

In keeping with the Commission's Order in Case No. 89-374,[49] $6,612[50] in legal expenses incurred for the LG&E Energy Corporation ("Holding Company") included in test-year operating expenses has been disallowed.

Trimble County Marketing Costs

Test-year costs of $156,434[51] associated with marketing the 25 percent disallowed portion of Trimble County has been excluded, decreasing operating expenses by $156,323. The AG had proposed to remove $500,000 in Trimble County expenses, but produced no evidence to support his assumptions.

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48 Responses to Data Requests from Hearing, filed December 5, 1990, Item 9.

49 Case No. 89-374, Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith, Order dated May 25, 1990.

50 Responses to Data Requests from Hearing, filed December 5, 1990, Item 8.

51 LG&E Hearing Exhibit No. 16.

State Sales Taxes

LG&E proposed to increase its state sales tax expense by $163,000 to reflect the change in the Kentucky sales taxes rate effective July 1, 1990. Although KIUC opposed this adjustment on the grounds that LG&E had not made necessary the pro forma adjustments, The Commission believes it is reasonable to reflect this change in the state sales tax rate and has increased the state sales tax expense by $163,000.

Office Supplies and Professional Services Expenses

The AG proposed to reduce LG&E's test-year expenses for office supplies and professional services by $1,818,791. This amount represented a reduction to the levels recorded in the year prior to the test year. The AG argued that LG&E had failed to meet its burden of proof in justifying these expense increases, and advocated the Commission further decrease LG&E's test-year expenses to reflect information provided subsequent to the hearing as well as improper items of expense included by LG&E but not detected by the AG.[52]

The Commission has reviewed the account description in the Uniform System of Accounts ("USoA") for Account No. 921, Office Supplies and Expenses. This account can include charges for items such as printing, stationary, meals, traveling, and incidental expenses. However, expenses charged to any account must be evaluated on the reasonableness of the charge and how appropriate it is to include the charge for rate-making purposes. The charges

52 Brief of AG, page 1.

questioned by the AG were recorded in subaccounts of Account No. 921 which were periodically "zeroed out." Thus, these charges were not included in the test-year balance for Account No. 921. Given the information available, the Commission finds reasonable the test-year level of expense recorded in Account No. 921.

Concerning the professional services, LG&E has shown that it had already removed or reduced several of these charges in its pro forma adjustments. The Commission has specifically reviewed the invoices provided to the AG for test-year legal charges. LG&E edited many of these invoices and provided only very brief descriptions for the edited items. LG&E claimed that it could not disclose the nature of certain legal activities under the attorney-client privilege. The invoices included charges for numerous proceedings involving Trimble County and other major issues before or with the Commission. The Commission believes it is reasonable to remove the charges for the numerous Commission related proceedings since this level of activity should not be as large with the completion of Trimble County, on a going forward basis. We have also removed charges relating to the invoices where descriptions have been omitted, reducing test-year professional services expense by $294,676.

Miscellaneous Expense Adjustments

The AG proposed to reduce miscellaneous expenses by $314,903. Included in this proposed adjustment were contributions, economic development donations, moving expenses, and commitment fees recorded above the line, which the AG argues were not the ratepayers responsibility. The AG also argued that LG&E's

commitment fees should not be as high as in the past, since these fees had been related to the financing needs of Trimble County.

We have removed the contributions, economic development donations, and the moving expenses from the test-year expenses. The Commission traditionally has excluded above the line contributions and donations from rates; and we have not been persuaded that the moving expenses incurred in the test year represent a recurring item of expense. However, it is reasonable to include the test year level of commitment fees, because LG&E will be incurring commitment fees for its financing requirements on a recurring basis. Taken together this reduces test-year miscellaneous expenses by $151,507.

Amortization of Management Audit Fee

In Case No. 10064, the Commission approved LG&E's request to amortize the cost of the Management Audit over a 3-year period. This resulted in an annual amortization of $194,000.[53] As of the end of the test year, $226,333[54] remained to be amortized. At the present amortization rate, LG&E would have recovered the cost by the middle of 1991.

LG&E should recover the total cost of the management audit but it is not entitled to recover in excess of its cost, requiring the amortization rate to now be adjusted. The annual amortization rate for rate-making purposes should be $75,444 based on a 3-year amortization of the unamortized cost at test-year-end.

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53 Case No. 10064, Order dated July 1, 1988, page 62.

54 April 1990 Monthly Report, page 28.

Considering that the amortization has continued during the course of these proceedings, LG&E will recover its entire cost by the middle of 1992 at the $75,444 annual amortization rate. Test-year expenses have been reduced by $118,560 to reflect this adjustment.

Annualization of Year-End Customers

LG&E proposed an increase in operating expenses of $1,118,728 to reflect the increase in expenses related to annualizing the number of customers at test-year-end. This adjustment corresponded to a similar adjustment to operating revenues.

The AG proposed an increase in operating expenses of $947,065. The AG made several adjustments to the operating expenses used in the calculation of the proposal, stating that several expenses included by LG&E had not been shown to vary with the number of customers. The AG further stated that absent an LG&E study which showed that expenses increased with customer growth revenues, any adjustment based on an operating ratio is not known and measurable.[55]

The Commission specifically used the operating ratio methodology in Case No. 10064 and LG&E has followed that methodology in preparing its proposal. We have accepted LG&E's proposed adjustment.

Directors and Officers Liability Insurance

The AG proposed to reduce expenses by $245,943 to reflect the assignment of 50 percent of the cost of directors and officers liability insurance to the shareholders of LG&E. The AG argued

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55 DeWard Direct Testimony, page 33.

that the protection provided by the insurance was for both the shareholder and ratepayer. While there may be some benefits to shareholders, the main beneficiaries are the ratepayers. This insurance allows LG&E to induce highly qualified individuals to serve on its Board of Directors. We feel it is not proper or reasonable to include this adjustment.

Workers' Compensation Insurance

The AG proposed to reduce expenses by $536,187 to reflect a portion of the Workers' Compensation insurance expense recorded in the test year as capitalized. The AG stated that it was unclear whether LG&E was capitalizing any of the Workers' Compensation insurance costs, but that such an adjustment was appropriate. LG&E indicated that it was in fact capitalizing its Workers' Compensation insurance costs.[56] The Commission believes the amount included as workers' compensation insurance expense is reasonable.

Amortization of Investment Tax Credits

LG&E proposed to increase the amortization of investment tax credits ("ITC") by $1,554,000. The proposal reflected the change in depreciation rates used by LG&E and the amortization of ITCs attributable to Trimble County. The proposal reflected Trimble County ITCs for plant to be in service as of December 31, 1990.

The AG, KIUC, and Jefferson et al. opposed the inclusion of the Trimble County ITC amortization for the same reasons expressed

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56 T.E., Volume IV, November 19, 1990, page 185.

concerning LG&E's proposed adjustment to depreciation expense related to Trimble County.

As discussed earlier in this Order, it is reasonable to nclude Trimble County CWIP as of test-year end and the related first year depreciation expense in rates. Likewise, it is reasonable to include the amortization on the Trimble County ITCs related to the April 30, 1990 balance of CWIP, which increases the amortization of ITCs by $1,507,000.[57]

Flowback of Unprotected Federal Excess Deferred Taxes

In Case No. 10064, the Commission ordered LG&E to amortize $4,749,500 in unprotected federal excess deferred taxes and $4,385,600 in state tax deficiencies over a 5-year period.[58] The AG claimed that LG&E did not appear to be in conformity with the Order in Case No. 10064 and proposed that the test year flowback of the unprotected federal excess deferred taxes be increased by $162,300. LG&E stated that it had changed the amount of the federal amortization due to the discovery of some errors in the amounts originally provided to the Commission in Case No. 10064, but even after the discovery of these errors, it had not informed the Commission of the change. LG&E filed information concerning the change in the amount of unprotected excess deferred taxes and its change in the amortization amount.

The Commission has reviewed the account information. It appears that both amortization amounts have been changed, not just

57 Fowler Direct Testimony, Exhibit 1, Schedule Y, line 5.

58 Case No. 10064, Order dated July 1, 1988, page 61.

the amortization for the federal excess deferred taxes. Insufficient information has been provided to justify a change in the federal amortization as ordered in Case No. 10064. The flowback of unprotected federal excess deferred taxes is restored to the level ordered in Case No. 10064 by $162,300.

State Income Tax Rate Change

LG&E proposed three adjustments to reflect the change in the Kentucky income tax rate, which became effective January 1, 1990. The adjustments were an increase in state income tax of $508,000; an increase in deferred state income tax of $42,000; and an increase in the amortization of cumulative state deferred tax of $512,000. In all three adjustments, LG&E computed the corresponding savings in federal income taxes relating to the state income tax rate change.

The methodology used to reflect the change in the state income tax rates is reasonable. But, based on the information provided, these adjustments require recalculations to reflect the level of state tax deficiency identified in Case No. 10064. The state income tax is increased by $508,000; deferred state income tax increased by $41,473; and the amortization of cumulative state deferred tax increased by $446,582.

Tax Adjustment for Other Interest Expense

LG&E proposed to increase income tax expense by $198,430 to reflect the income taxes applicable to other interest expense. In Case No. 10064, the Commission determined that LG&E could not recover other interest expense from ratepayers. Because LG&E could not recover this expense from ratepayers, LG&E claims that the ratepayers should not receive any corresponding income tax benefits. We do not agree. According to the USoA, other interest expense is recorded below the line.

It is not proper to make the proposed adjustment to income tax expense without supporting documentation which shows LG&E included other interest expense in the determination of its above-the-line income tax expense.

Interest Synchronization

LG&E proposed two adjustments in order to determine its interest synchronization. The first adjustment annualized the interest expense on debt, and the second reflected the allocation of JDIC on the computation. Traditionally, the Commission has applied the cost rates applicable to the long-term debt and short-term debt components of the capital structure in order to compute an interest adjustment. This was the approach the Commission used in Case No. 10064. The debt components utilized in this computation reflect the effects of the JDIC allocation and reductions to capital structure due to the 25 percent Trimble County disallowance and the capital costs of LG&E's new office building. Using the adjusted capital structure allowed, the Commission has computed an interest reduction of $1,193,023 which results in an increase to income taxes of $470,588.

Following the approach used in Case No. 10064, the Commission has applied the combined state and federal income tax rate of 39.445 percent to the accepted pro forma adjustments. The Commission finds that combined operating income should be increased by $6,639,060 to $130,376,955.

The adjusted net operating income is as follows:

	Electric	Gas	Total
Operating Revenues	$502,388,881	$183,296,032	$685,684,913
Operating Expenses	384,835,893	170,472,065	555,307,958
ADJUSTED NET OPERATING INCOME	$117,552,988	$ 12,823,967	$130,376,955

RATE OF RETURN

Capital Structure

LG&E proposed an adjusted end-of-test-year capital structure containing 43.13 percent long-term debt, 4.69 percent short-term debt, 8.22 percent preferred stock, and 43.96 percent common equity. Year-end, long-term debt was adjusted to reflect: (1) the retirement of $16,000,000 of 4 7/8 percent First Mortgage Bonds, Series due October 1, 1990;[59] (2) the scheduled redemption of $750,000 of 1975 Pollution Control Bonds due September 1, 1990;[60] and (3) the refinancing of $25,000,000 of Series J 1985 Pollution Control Bonds at 8.25 percent interest with 1990 bonds at 7.45 percent interest.[61] The retirement of the $16,000,000 of 4 7/8 percent First Mortgage Bonds and the redemption of the $750,000 1975 Pollution Control Bonds were reflected as adjustments to short-term debt. The refinancing of the 1985

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59 Fowler Direct Testimony, Exhibit I, Schedule V.

60 Id.

61 T.E., Volume IV, November 19, 1990, page 11.

Series J Pollution Control Bonds with 1990 bonds did not affect the capital structure.

LG&E decreased year-end preferred stock and increased common equity by $1,033,459, the discount and expense associated with the preferred stock issues.[62] LG&E also decreased common equity by $9,251,593 to reflect the adjustment to retained earnings for unbilled revenues as discussed previously in this Order.[63]

The AG proposed a capital structure containing 43.11 percent long-term debt, 4.69 percent short-term debt, 8.30 percent preferred stock, and 43.90 percent common equity.[64] The difference in the AG's proposal and LG&E's proposal is that the AG proposed to exclude unamortized premiums, discounts, and expenses. The AG claims these amounts are not a part of the permanent financing of a utility. Moreover, the AG disagreed with LG&E's adjustment to place the preferred stock discount and expense in the weighted average of preferred stock.[65] The AG maintained that the preferred stock discount and expense was properly recorded in the capital stock account and should remain in the weighted average of common equity.

Premiums, discounts, and other expenses of issuing securities are an integral part of the financing of a utility and should be

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62 Fowler Direct Testimony, page 1 of 2.

63 Id., page 1.

64 Weaver Direct Testimony, Exhibit, Statement 17.

65 Id., page 30.

reflected as such in the capital structure. LG&E's adjustment to place the discount and expenses associated with preferred stock in the preferred stock structure is appropriate. The Commission finds LG&E's capital structure is as follows:

	Percent
Long-Term Debt	43.13
Short-Term Debt	4.69
Preferred Stock	8.22
Common Equity	43.96
Total Capital	100.00%

Cost of Debt and Preferred Stock

LG&E proposed a cost of long-term debt of 7.72 percent after adjustments for the refinancing of the $25,000,000 1985 First Mortgage Bonds.[66] The AG proposed a cost of long-term debt of 7.79 percent[67] but did not include an adjustment for refinancing the 1985 First Mortgage Bonds. To arrive at its cost of long-term debt, LG&E included the unamortized premium on bonds in long-term debt and adjusted interest expense by the amortization of expenses, premiums, and the loss on reacquired debt.[68] The AG did not include the unamortized premium on bonds in long-term debt and adjusted interest expense by the amortization of the expenses and

66 Calculated from Fowler Direct Testimony, Exhibit 2, page 1; and T.E., Volume IV, November 19, 1990, page 11.

67 Weaver Response to LG&E, 17.

68 Fowler Direct Testimony, Exhibit 2, page 1; and Exhibit 1, Schedule V.

premium but did not adjust interest expense by the amortization of the loss on reacquired debt.[69]

It is more appropriate to adjust long-term debt by the unamortized premium on bonds and to adjust interest expense by the amortization of the loss on reacquired debt. We find the cost of long-term debt to be 7.72 percent.

LG&E proposed the cost of short-term debt to be 8.38.[70] The AG proposed the cost of short-term debt to be 8.43.[71] The AG subsequently agreed with a cost of 8.38, and the Commission concurs.

LG&E[72] and the AG[73] both agreed that the cost of preferred stock is 8.09 percent and the Commission concurs.

Return on Equity

LG&E proposed a return on equity ("ROE") in the range of 13.0 to 13.5 percent,[74] and subsequently revised its expected cost of equity to be in the range of 13.25 to 13.75 percent.[75] The AG proposed a range of 12.0 to 12.5 percent.[76] KIUC proposed an ROE

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69 Weaver Direct Testimony, Exhibit, Statement 15.

70 Fowler Direct Testimony, Exhibit 2, page 1.

71 Weaver Direct Testimony, Exhibit Statement 16, page 2.

72 Fowler Direct Testimony, Exhibit 2, page 1.

73 Weaver Direct Testimony, Exhibit, Statement 17.

74 Olson Direct Testimony, page 36.

75 Olson Supplemental Testimony, page 18.

76 Weaver Direct Testimony, page 28.

of 11.7 percent.[77] Jefferson et al. proposed an ROE in the range of 11.0 to 11.5 percent.[78]

To determine the ROE, LG&E used a discounted cash flow ("DCF") analysis. In addition, LG&E utilized an interest premium calculation and DCF study of eight other electric utilities as a check on the results of its DCF analysis. LG&E adjusted the results for financing costs and to show additional margin.

In its DCF analysis, LG&E used a dividend yield of 7.57 percent[79] based on a projected dividend rate of $2.84 and a 6-month high/low stock price average during the period May 1 - October 26, 1990.[80] LG&E relied on three methods of analysis to determine its estimated growth rate: 1) a study of past and current trends in dividends, earnings and book value; 2) retention or internal growth; and 3) estimates of expected growth available from security analysts.[81] Based on its analysis, LG&E opined that investors expect growth of 4.75 to 5.25 percent.[82] Overall, LG&E's DCF analysis produced a return requirement of 12.32 to 12.82 percent.[83]

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77 Baudino Direct Testimony, page 26.

78 Kinloch Direct Testimony, page 22.

79 Olson Supplemental Testimony, page 17.

80 Id.

81 Olson Direct Testimony, page 23.

82 Id., page 29.

83 Olson Supplemental Testimony, page 17.

Using an interest premium approach as a first check on its DCF analysis, LG&E concluded its cost of common equity to be 14.5 percent. The risk premium of investors was estimated to be 4.75 percent. This was added to the current yield to maturity on Double A bonds of 9.8 percent.[84] As a second check of its results, LG&E performed a DCF study of eight selected utilities. The results indicated an investor requirement of 12.48 to 12.98 percent.[85]

LG&E determined that the results of its DCF analysis were not in fact the returns required by investors. LG&E applied an 8 percent premium to its DCF results to compensate for financing cost and market pressure.[86] LG&E concluded that its required ROE should be 13.25 to 13.75 percent.[87]

To perform a DCF analysis, the AG selected 5 companies he considered to be of comparable risk to LG&E. The companies considered were combination gas and electric companies reported in Value Line with characteristics similar to LG&E in capital structure ratios, total assets, fuel mix, electric vs. gas revenue distribution, betas, stock ratings, and bond ratings.[88] According to the AG's analysis, LG&E has a slightly greater amount of risk from its capital structure and operating leverage than the

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84 Olson Direct Testimony, pages 32-33.

85 Olson Supplemental Testimony, page 18.

86 Olson Direct Testimony, page 36.

87 Olson Supplemental Testimony, page 18.

88 Weaver Direct Testimony, page 6.

comparison group but this risk is offset by the greater risk of the comparison group from acid rain legislation.[89]

The AG used four methods of calculating growth for its DCF analysis. The methods used were: 1) compound growth rate in dividends per share; 2) compound growth rate in earnings per share; 3) compound growth rate in book value per share; and 4) earnings retention ratio multiplied by ROE. Based on these calculations, the AG's recommended growth rate was 4.0 to 4.5 percent.[90]

The AG calculated a dividend yield from June 29, 1990 through September 7, 1990 of 7.44 percent for LG&E and 7.75 percent for the comparison group.[91] The AG employed these yields in its DCF analysis to reflect greater uncertainty caused by the Middle East situation.[92] The results of the AG's DCF analysis yielded an ROE for LG&E of 11.74 to 12.27 percent and 12.06 to 12.60 percent for the comparable companies.[93] Based on these results the AG determined LG&E's required ROE to be within a range of 12.0 to 12.5 percent.[94]

KIUC performed a DCF analysis using the same eight companies that LG&E used in its DCF study of comparable companies and a risk

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89 Id., page 18.

90 Id., page 25.

91 Id., page 26.

92 Id.

93 Id., page 27.

94 Id., page 28.

premium analysis. KIUC calculated a 6-month average dividend yield during the period from February through July 1990 of 7.22 percent for the comparison group[95] and 7.28 percent for LG&E.[96] Averaging the Institutional Brokers Estimate System ("IBES") earnings growth project, Value Line compound dividend growth rate from 1990 to 1994, and Value Line compound earnings per share growth rate from 1990 to 1994 resulted in an expected growth rate of 4.28 percent for the comparison group[97] and 3.46 percent for LG&E.[98] To complete the DCF equations, KIUC applied one-half the growth rate to the historical dividend yields to arrive at a ROE for the comparison group of 11.65 percent[99] and 10.87 percent for LG&E.[100] KIUC opined that its DCF cost of equity for LG&E was too conservative given the DCF cost of equity for the comparison group.[101] KIUC found the comparison group results were not understated based on a sustainable growth calculation it performed as a check.[102]

In addition, KIUC performed a risk premium analysis as a supplementary check on its DCF analysis. Adding a risk premium of

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95 Baudino Direct Testimony, page 11.

96 Id., page 18.

97 Id., page 13.

98 Id., page 19.

99 Id., page 16.

100 Id., page 20.

101 Id., page 21.

102 Id., page 25.

2.11 percent to the 9.65 percent average yield of LG&E's first mortgage bonds for February and July 1990 resulted in a cost of equity for LG&E of 11.76 percent.[103] In its final analysis, KIUC averaged the results of its DCF for comparison companies and its risk premium analysis to arrive at its estimate of 11.7 percent as a fair rate of return for LG&E.[104]

Jefferson et al. opined that an ROE between 11.0 and 11.5 percent would offer LG&E's shareholders a fair return on their investment.[105] This was based on a review of returns recently granted by other Commissions as published in Public Utilities Fortnightly and KIUC's assessment of LG&E's level of risk as compared to the named utilities.

The 8 percent premium proposed by LG&E to adjust for flotation cost and market pressure would overstate LG&E's cost of capital. LG&E is rated a solid Aa/AA by Moody's and Standard and Poor and thus can be considered less risky than the average utility investment. Pressure to finance ongoing construction is declining and by its own admission, LG&E is in a one-of-a-kind position to perform under the Clean Air Act. However, the current state of the economy is timorous. The Commission, having considered all of the evidence, including current economic conditions, finds that an ROE of 12.25 to 12.75 percent is fair, just, and reasonable. An ROE in this range would allow LG&E to

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103 Id., page 24.

104 Id., page 26.

105 Kinloch Direct Testimony, page 22.

attract capital at a reasonable cost and maintain its financial integrity to ensure continued service and provide for necessary expansion to meet future requirements, and also result in the lowest possible cost to ratepayers. A return of 12.5 percent will best meet the above objectives.

Rate of Return Summary

Applying the rates of 7.79 percent for debt, 8.09 percent for preferred stock, and 12.50 percent for common equity to the capital structure produces an overall cost of capital of 9.89 percent, which we find to be fair, just, and reasonable. This cost of capital produces a rate of return on LG&E's net original cost rate base of 9.52 percent which the Commission finds is fair, just, and reasonable.

REVENUE REQUIREMENTS

The Commission has determined that LG&E needs additional annual operating income of $3,618,915 to produce a rate of return of 12.50 percent on common equity based on the adjusted historical test year. After the provision for state and federal taxes, there is an overall revenue deficiency of $5,976,245 the amount of additional revenue granted. The net operating income necessary to allow LG&E the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $133,995,870. A breakdown between electric and gas operations of the required operating income and the increase in revenue allowed is as follows:

	Electric	Gas	Total
Net Operating Income Found Reasonable	$120,854,300	$ 13,141,570	$133,995,870
Adjusted Net Operating Income	117,552,988	12,823,967	130,376,955
Net Operating Income Deficiency	3,301,312	317,603	3,618,915
Gross Up Revenue Factor for Taxes [1.00-.39445]	.60555	.60555	.60555
Additional Revenue Required	5,451,758	524,487	5,976,245

The additional revenue granted will provide a rate of return on the net original cost rate base of 9.52 percent and an overall return on total capitalization of 9.89 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $691,661,158. These operating revenues include $507,840,639 in electric revenues and $183,820,519 in gas revenues. The gas operating revenues reflect the most recent gas cost adjustment approved in Case No. 10064-J.

PRICING AND TARIFF ISSUES

Electric Cost-of-Service Study

LG&E presented a fully embedded time-differentiated electric cost-of-service study for the purpose of allocating costs among the classes of service on the basis of cost incurrence. The study used a base-intermediate-peak ("BIP") method to allocate production and transmission costs to costing periods and to customer classes. The BIP methodology, which was approved by the

Commission in Case Nos. 8616,[106] 8924,[107] and 10064,[108] was described by LG&E in the following manner:

> The cost assignments to the base period were established on the basis of the relationship of the minimum demand to the maximum demand. This recognized that some level of capacity is always present to meet customer needs. Base costs were allocated among classes based on their individual contribution to the average system demand. Intermediate peak costs were determined on the basis of the maximum winter peak demand over and above the average demand. Such costs were then assigned to the winter peak period based on the relationship of the number of hours in that period to the total hours in both the winter and summer peak periods. Costs were then allocated among customer classes according to each class's contribution to the winter peak demand. The remaining production and transmission costs were assigned to the summer peak period and allocated on the basis of each class's contribution to the summer peak demand.[109]

All other electric cost-of-service methodologies used by LG&E are essentially the same as those approved by the Commission in LG&E's last two rate cases.

KIUC recommended that demand-related costs be allocated to customer classes using the Probability of Peak ("POP") method. This method represents a type of coincident peak allocation in which each class's contribution to the utility's twelve monthly

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[106] Case No. 8616, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, Order dated March 2, 1983, pages 33-34.

[107] Case No. 8924, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, Order dated May 16, 1984, pages 37-38.

[108] Case No. 10064, Order dated July 1, 1988, pages 81-84.

[109] Walker Direct Testimony, pages 11-12.

system peaks are weighted by a given month's relative probability of attaining the annual system peak.[110] KIUC concluded that LG&E's electric cost-of-service study could not be used because it does not properly assign costs to customer classes. KIUC argued that the BIP method is deficient because it allocates a portion of demand-related production and transmission costs on an energy basis and assigns too much of the remaining weight to LG&E's winter system peak.[111]

According to LG&E, the POP method proposed by KIUC results in an assignment of nearly 90 percent of the weight of production and transmission costs to the coincident peaks that occurred during the summer months of July and August, with over 97 percent assigned to the June-September period.[112] LG&E further contended that the POP method leads directly to a class allocation in which the lighting schedules, Rates PSL, OL, and SLE, are assigned no portion of the production and transmission demand-related costs even though customers served under those rate schedules have access to power whenever they desire it.[113] KIUC even stated that "demand-related fixed costs are incurred due to the utility's obligation to provide service when requested".[114] LG&E stated that the BIP method is superior to the POP method in reflecting

110 Kalcic Direct Testimony, page 11.

111 Id., page 10.

112 Brief of LG&E, page 122.

113 Id., pages 122-123.

114 Kalcic Direct Testimony, page 8.

the realities of cost incurrence on its system and should be used in the analysis of cost of service.[115]

The Commission continues to believe that the BIP method is appropriate as a means of allocating production and transmission costs to the customer classes. The BIP method recognizes that LG&E's embedded production and transmission costs were incurred to meet all customer demand, not just that which is coincident with system peak. KIUC's proposed POP method places too much weight on coincident peak demand. If any customer has access to electricity whenever it is demanded, that customer should bear the responsibility of some portion of demand-related costs.

LG&E's electric cost-of-service study is acceptable and should be used as a starting point for electric rate design.

Gas Cost-of-Service Study

LG&E filed a fully embedded gas cost-of-service study to allocate costs among the classes of service on the basis of cost incurrence and to determine the relative contribution that each rate class makes to overall return on net rate base. Pursuant to a Commission directive in Case No. 10064, LG&E disaggregated its customers in this cost-of-service study into the following classes: Residential Rate G-1, Commercial Rate G-1, Industrial Rate G-1, Commercial Rate G-6, Industrial Rate G-6, and Fort Knox

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115 Brief of LG&E, page 123.

Special Contract.[116] For purposes of this study, LG&E combined the sole customer served under Uncommitted Gas Service Rate G-7 with Industrial Rate G-6.[117] LG&E stated, however, that the provision of service to Rate G-7 customers is markedly different from that provided to Rate G-6 customers.[118]

LG&E did not disaggregate the customer classes further into transportation and sales categories. LG&E contended that since all transportation customers may purchase any portion of their annual gas requirements under the applicable sales rate schedules, and since all but one of its transportation customers purchased sales gas during the test year, a disaggregation of transportation customers would be unnecessary.[119]

LG&E's cost-of-service model consists of the following steps: (1) costs are assigned to the major functional groups (underground storage, transmission, distribution general, distribution structures, distribution mains, distribution services, distribution meters, customer accounting, and customer services); (2) functionalized costs are then classified into demand, commodity, and customer components; and then (3) classified costs

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116 In the Commission's Order in Case No. 10064 dated July 1, 1988, at page 81, LG&E was directed to address, in its next rate case, an assertion made by KIUC that LG&E's cost-of-service study did not fully disaggregate its various classes of customers.

117 Walker Exhibit 2, page 1.

118 <u>Id</u>.

119 Brief of LG&E, page 125.

are allocated to LG&E's rate classes.[120] LG&E's gas cost-of-service methodologies are consistent with those approved by the Commission in Case No. 10064.

The AG criticized several allocation methodologies used by LG&E and suggested alternative allocation factors. The AG, however, did not conduct a cost-of-service study incorporating his recommended allocation factors.[121]

The AG proposed to allocate exactly half of the demand-related underground storage and transmission costs on the basis of extreme winter seasonal requirements and design-day demand, the same factor LG&E used to allocate all of the storage and transmission demand costs in its cost-of-service study. The AG recommended that the other half be allocated on the basis of total class usage.[122]

Similarly, the AG proposed to allocate half of the commodity-related storage and transmission costs on the basis of design-day demand, with the other half allocated on the basis of total class usage.[123]

The AG proposed to allocate one-third of the costs associated with distribution structures and equipment on the basis of class

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[120] Walker Exhibit 2, page 2.

[121] T.E., Volume VII, November 26, 1990, pages 12-13.

[122] Sheehan Direct Testimony, pages 10-11.

[123] Id., page 12.

design-day demand, with the remaining two-thirds allocated on the basis of total class usage.[124]

Finally, the AG recommended substituting a usage-based allocator or a different customer-based allocator for LG&E's customer-based allocator for the allocation of costs associated with customer accounting and customer service expenses.[125]

The AG has provided no evidence to support the reasonableness of his cost-of-service allocation methodologies. In fact, when asked to explain the basis for one of his proposed methodologies, the AG's witness vaguely characterized it as "rule of thumb" and "reasonable at a first glance."[126] He also indicated that some of his other recommended methodologies could be similarly described.[127] Explanations such as that hardly support the reasonableness of the AG's recommended allocation methodologies. Furthermore, the AG is unable to quantify the effect his recommendations will have on class rates of return.[128] Considering the lack of support for the AG's recommendations, the Commission is unable to adopt them as alternatives to LG&E's allocation methodologies.

KIUC criticized LG&E's gas cost-of-service study because it does not establish separate classes for transportation customers

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124 Id., page 14.

125 Id., pages 16-19.

126 T.E., Volume VII, November 26, 1990, page 54.

127 Id., pages 55-56.

128 Id., page 58.

and sales customers. It contended this absence renders the study useless with respect to the design of cost-based transportation rates.[129]

KIUC asserted that the cost incurrence characteristics of transportation service are significantly different from those of sales service based on an analysis of load factor and customer size data for G-1 and G-6 sales and transportation customers. KIUC contended that the larger load factors and customer sizes of transportation customers indicate "radically different" cost incurrence,[130] and asserted that the gas cost-of-service study should disaggregate transportation customers from sales customers.

KIUC presented an alternative gas cost-of-service study in which commercial and industrial G-1 and G-6 customers are disaggregated further into separate sales classes and transportation classes. With respect to the allocation methodologies utilized to assign costs to these classes, KIUC adopts the same methodologies employed by LG&E in its study.[131]

KIUC's reliance on load factor and customer size data to prove a significant difference in cost incurrence characteristics is not sufficient to convince the Commission that such an extreme cost differential exists. LG&E has clearly shown that all but one of its transportation customers also relied upon and used sales

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129 Eisdorfer Direct Testimony, page 3.

130 Id., page 6.

131 Id., pages 8-9.

service to some degree during the test year.[132] This ability of transportation customers to rely upon and use sales services is a privilege not adequately considered by KIUC in its analysis. Nor does KIUC's analysis acknowledge that LG&E's distribution system is constructed in a manner so as to provide sales service to these customers whenever such service is demanded. These factors must be considered when attempting to determine differences in cost incurrence characteristics between customers. KIUC's evidence lacks such consideration and analysis.

LG&E has stated that certain differences exist in the provision of service to Rate G-6 customers and Rate G-7 customers.[133] Yet LG&E combined its one G-7 customer with the Rate G-6 class for purposes of its cost-of-service study. LG&E should, in subsequent cost-of-service studies, fully disaggregate Rate G-7 customers from those served under Rate G-6.

LG&E's gas cost-of-service study is acceptable and should be used as a starting point for gas rate design.

Revenue Allocation

Based on the results of its electric cost-of-service study, LG&E proposed to allocate increases to all customer classes ranging from 7.4 percent for the residential and street and outdoor lighting classes to 5.9 percent for the general service and special contract classes. LG&E indicated that its allocation

132 T.E., Volume VII, November 26, 1990, page 93.

133 Walker Exhibit 2, page 1.

methodology was designed to achieve a better balance between class rates of return while maintaining rate stability and continuity.

LG&E proposed to allocate the full amount of the gas increase to the General Service ("G-1") rate. This proposal was based on the results of LG&E's cost-of-service study which showed that the rate of return for the residential class, which is served under the G-1 rate schedule, was significantly below rates of return for other classes. LG&E proposed no increases for its interruptible rate classes, G-6 and G-7, or for the Fort Knox special contract.

KIUC, based on its electric cost-of-service study, proposed allocations ranging from a 5.6 percent decrease for Carbon Graphite, a contract customer, to a 13.1 percent increase for the residential class. On gas, KIUC proposed decreases for G-1 and G-6 industrial transportation customers. The amount of the decreases were dependent on the amount by which the Commission reduced LG&E's requested gas increase. None of the other intervenors offered specific allocation recommendations.

LG&E's allocation proposals are supported by its cost-of-service analyses and are consistent with the Commission's goals of gradualism and rate continuity. Having accepted LG&E's cost-of-service studies, the Commission finds that the resulting allocation proposals produce an equitable distribution of the revenue increases granted and shall be reflected in the rate design approved herein.

Electric Rate Design

LG&E proposed generally uniform increases in customer, demand and energy charges with some changes in its existing tariffs and rate design. The changes included: switching from a minimum bill to a customer charge for its water heating, space heating, and traffic lighting rates; changes in demand ratchets that would impact the billing demands for large commercial and industrial customers; seasonal billing demands for industrial customers served under rate LP; and making time-of-day rates available for smaller sized industrial and commercial customers. In addition, LG&E proposed changes in Public Street Lighting ("PSL") and Outdoor Lighting ("OL") rates to equalize the prices, by lumens of output, between mercury vapor and high pressure sodium lights. LG&E also proposed to revise its interruptible service rider by increasing the monthly demand credit to $3.30 per KW.

Louisville opposed LG&E's proposed changes to the PSL rates contending that the marginal cost pricing methodology employed by LG&E unfairly impacted Louisville with its older, more fully depreciated street lighting system. Louisville recommended an alternative rate schedule based on embedded costs and proposed to be separated from LG&E's other PSL customers either through a special contract or by establishing a separate tariff classification.

Jefferson et al. proposed changing LG&E's residential rate structure from a flat summer rate and declining block winter rate to inverted block rates in both summer and winter. Jefferson et al. opines that LG&E was deficient in its response to the Commission's directive in Case No. 10064 that LG&E address the issues of inverted block rates in the summer and declining block winter rates.[134] Jefferson et al., based on its analysis of LG&E's cost-of-service study, contends that LG&E's temperature-sensitive loads (summer air conditioning and winter heating) have a major impact on LG&E's costs and the allocation of those costs. Jefferson et al. proposes that LG&E's cost recovery, through rates, should also reflect the impact of these temperature-sensitive loads.

Jefferson et al.'s proposal would reduce LG&E's energy rate for the first 600 KWH to 5.435¢ on a year-round basis compared to LG&E's existing rates of 6.402¢ and 5.833¢ in the summer and winter, respectively. Jefferson et al. would increase the rate for sales over 600 KWH to 8.189¢ in the summer and 6.227¢ in the winter compared to the existing rates of 6.402¢ in summer, and 4.528¢ in winter. These rates were based on Jefferson et al.'s analysis of LG&E's temperature-sensitive costs using the base, winter, and summer demands from LG&E's cost-of-service study and using one month of the test year, October 1989, as the measure of LG&E's non-temperature-sensitive load.

LG&E argues that while unit costs are higher in the summer than in the winter there is no load research evidence to support Jefferson et al.'s proposal. LG&E contends that its existing rate design reflects the differences in summer and winter unit costs and, through the declining block winter rate, attempts to reduce the average unit cost by spreading fixed costs over greater sales volumes. LG&E further contends that deficient recovery of

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[134] Case No. 10064, Order dated August 10, 1988.

customer costs through the customer charge requires these costs to be recovered in the initial usage steps to prevent large users from paying a disproportionate share of these costs. Finally, LG&E argues that its declining block winter rates should be continued to promote off-peak loads and that customer acceptance and revenue stability must be included in any consideration of rate design changes.

The Commission finds most of LG&E's rate design changes proper and reasonable. On PSL and OL rates, the Commission finds LG&E's alternative proposal proper and reasonable. The alternative proposal, to which Louisville agreed, results in approximately equal percentage increases for existing lights, be they mercury vapor or high pressure sodium.[135] For mercury vapor lights installed in the future, the rates would be higher, based on LG&E's marginal costs, while for new high pressure sodium lights the rates would equal the rates for existing lights.

The Commission is not persuaded that LG&E's residential rates should be redesigned in the precise manner proposed by Jefferson et al.; however, we find that a change resulting in an inverted block summer rate is appropriate. The Commission finds there to be substantial support for Jefferson et al.'s proposed inverted summer rates. LG&E is a strong summer peaker with a significant amount of capacity installed to meet its residential air conditioning load. As LG&E pointed out, its unit costs are higher in the summer than in the winter largely due to the relatively

[135] T.E., Volume V, November 20, 1990, page 111.

small increment of energy sales associated with the capacity required to meet its air conditioning demands.[136] These summer load characteristics indicate that LG&E's temperature- sensitive load is a major contributor to its generating and transmission costs and point out the need for long-term reductions in peak demand that can translate into lower future costs.

The Commission considers reduced peak demand, improved system load factor, and lower unit costs to be common goals that are in the best interest of all parties. To that extent, we are not persuaded that LG&E's winter rate design should be modified. Increased off-peak loads can produce many of the same benefits as reduced on-peak loads.

In recognition of concerns about cost recovery, customer acceptance, and revenue stability we have chosen a moderate approach to the implementation of an inverted block summer rate. The summer energy rate will remain unchanged for the first 600 KWH usage; the summer energy charge increase will be assigned in total to the usage in excess of 600 KWH. Given the relatively small number of KWH sold in relation to the capacity needed to meet air conditioning demands, this increase should not affect LG&E's revenue stability.

Cable Television Attachment Charges ("CATV")

LG&E proposed increasing its charges for CATV pole attachments by approximately 35 percent. LG&E's calculation of these charges was based on the formula established by the

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136 Walker Direct Testimony, page 22.

Commission in Administrative Case No. 251[137] with an added cost component for tree trimming expense.

KCTA opposed the increase contending that LG&E's allocation of the entire amount of tree trimming expense included in Account 593.004, Tree Trimming of Electric Distribution Routes, to poles was improper. KCTA opined that the vast majority of the expense goes not to clear space for poles, but to clear space for LG&E's overhead conductions and services and for clearing a path for the span of lines between the poles. KCTA proposed allocating the tree trimming expense based on LG&E's investment in poles compared to its combined investment in poles, overhead conductors, and services, thereby increasing LG&E's pole attachment charges by approximately 14 percent. KCTA also proposed that the approved pole attachment rates be calculated using the overall rate of return approved by the Commission in this case.

LG&E argued that since the cable television lines are strung between the poles, those lines are benefited by the tree trimming that clears the path between the poles. LG&E also pointed out that pole attachment charges are assessed through a formula, based on the percentage of usable space, that uses an allocation factor to derive the appropriate charge.

The clearing of the span between the poles inures to the benefit of all parties whose lines cover the span, be they

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137 Administrative Case No. 251, The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments, Order dated August 12, 1982.

electric, telephone, or CATV. As such, the full amount of the tree trimming expense is properly includible in calculating the O & M component of the annual carrying cost used to derive the pole attachment charge. Applying the annual carrying charge to an allocated fix cost component, derived using the percentage of usable space, effectively allocates the O&M component of the annual carrying charge. The result is a pole attachment charge which reflects an equitable allocation and recovery of LG&E's costs. The pole attachment charges proposed by LG&E, modified to reflect the overall rate of return of 9.89 percent, are granted.

Gas Rate Design

For the G-1 class, LG&E proposed to increase customer charges by approximately 24 percent and commodity charges by approximately 1.8 percent. This proposal reflected the results of LG&E's cost-of-service study and the need to improve the residential rate of return. LG&E maintains that since the average residential usage is significantly smaller than the usage of the commercial and industrial classes served under Rate G-1, the customer charge, rather than the commodity charge, is the appropriate rate to increase for the purpose of achieving a better balance between class rates of return.

The AG opposed the proposed increase in the residential customer charge from $4.35 to $5.40, taking issue with several of LG&E's cost allocators used in arriving at its customer costs. The AG argued that the proposal acted as a disincentive for conservation by placing the bulk of the increase on the fixed portion of the customer's bill. The AG calculated a customer cost of $3.75 and opined that the existing charge of $4.35 was more than adequate.

Jefferson et al. maintained that the customer charge increase would overly burden the small, lower income customers in the residential class. Jefferson et al. argued that LG&E's stated intention of increasing the residential class rate of return was improper because the lower risk associated with serving the residential class should translate into a lower rate of return. Jefferson et al. proposed a rate design that included increasing the customer charge by 2.4 percent, the amount of the overall requested G-1 rate increase.

Although LG&E's proposal for increasing the customer charge may be logical and reasonable, the amount of the increase is not consistent with the Commission's goals of rate continuity and gradualism. While there is a lower risk associated with serving the residential class some increase in the residential class rate of return is warranted. As a means of achieving this increase in return, it is proper to assign the majority of the revenue increase to the customer charge. Given the magnitude of the increase, the Commission will assign the customer charge an increase of approximately 2.5 times the overall G-1 percentage increase, exclusive of gas cost revenues. The revenue increase of .9 percent results in a customer charge increase of 2.3 percent, producing a residential customer charge of $4.45. The non-residential customer charge will increase by a similar percentage, from $8.70 to $8.90.

Late Payment Charges

The AG proposed that LG&E's late payment charge be abolished. The AG argued that the charge was not cost-justified and that LG&E had not shown that the charge served as an incentive for prompt payment.

Jefferson et al. proposed a plan to change the way LG&E credits partial payments as a means of reducing the number of late payment charges imposed on customers with past due account balances. At present, LG&E credits partial payments first to the customer's past due balance, then to the current month's bill. Jefferson et al. pointed out that this procedure results in a customer being assessed a late payment charge when it makes a partial payment sufficient to cover its current month's bill because, after the payment is credited to the customer's past due balance, the remainder is not enough to cover the current month's balance. Jefferson et al. argued that this change would encourage customers to make timely payments on their current balances knowing there would be no late payment penalty assessed in a subsequent month when the current month's bill was paid in full.

LG&E argued that the existing procedure serves as an incentive for customers to pay off their past due balances and that the late payment charge functions as an incentive to encourage timely payments. LG&E also argued that if the late payment charge were abolished, the loss of the associated revenues would have to be incorporated into the rates charged all customers.

LG&E's late payment charge has been in its tariffs for many years. The AG performed no analysis on the effectiveness of this charge as an incentive for timely payment of bills. The Commission finds, as it did in LG&E's last rate case,[138] that the late payment charge serves as an incentive and has an important role in LG&E's bill collection strategy.

The arguments of Jefferson et al. to change the way LG&E credits partial payments are persuasive. The Commission finds Jefferson et al.'s plan to be a means of minimizing the instances of recurring late payment charges for customers experiencing payment problems. When a customer can pay the current month's bill plus make a payment toward its past due balance, the customer should not be assessed still another late payment charge.

The Commission is mindful of LG&E's concerns that implementation of Jefferson et al.'s proposal could result in customer laxity toward the payment of past due balances. In considering those concerns, the Commission notes that LG&E retains the ability to terminate service if payment is not eventually made. However, to minimize the need for such actions, the Commission will make the following modification to Jefferson et al.'s proposal to create an incentive for customers to reduce their past due balances: When a customer with a past due balance makes a partial payment sufficient to pay the bill for the current month's usage, plus pay $10.00 or 5 percent of the outstanding past due balance, whichever is greater, LG&E shall credit the

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[138] Case No. 10064, Order dated April 20, 1989.

payment to the current month's bill first, then credit the remainder to the past due balance. Crediting the current month's bill first will eliminate the assessment of a late payment penalty on the current month's bill, and requiring some payment toward the past due balance as a prerequisite for such crediting provides the customer an incentive to reduce the past due balance. The Commission finds that such a plan is a reasonable modification to LG&E's current collection procedures and should be approved. LG&E is hereby directed to implement this change in the way it credits partial payments concurrent with the effective date of this Order.

Transportation Service/Standby Service

KIUC recommended that LG&E's tariffs be modified to make standby service optional for all gas transportation customers. KIUC claimed that, under LG&E's existing tariffs, transportation service exclusive of standby service was limited to Rate T transportation customers taking sales service under Rate G-7, Uncommitted Gas Service. KIUC argued that this prerequisite effectively forced transportation customers to take standby service under Rate TS which is available to customers served under sales rates G-1 and G-6.

LG&E contends that Rate T is available to G-1 and G-6 sales customers but that a customer served on Rate T will have no standby or back-up protection for its Rate T volumes other than the G-7 rate for uncommitted gas service.[139] LG&E maintains that

[139] T.E., Volume II, November 9, 1990, pages 115-116.

KIUC has misinterpreted the Rate T tariff regarding the precondition of being a G-7 sales customer.

The Commission can understand KIUC's reading and interpretation of the Rate T tariff language which states "available to commercial and industrial customers serviced under Rate G-7. . ." to mean that being a G-7 sales customer is required in order to receive transportation service under Rate T. We also understand LG&E's explanation that the intent of the tariff is to indicate that for customers taking transportation service under Rate T, LG&E will not be obligated to provide standby quantities other than the uncommitted gas available under Rate G-7. Some modification of the tariff language regarding the availability of Rate T is needed to eliminate this misunderstanding. The above-quoted reference to Rate G-7 should be eliminated and a description of the limited protection of uncommitted gas offered under Rate G-7 should be added. LG&E should so modify this tariff when it files its revised tariffs setting forth the rates approved in this proceeding.

<u>Pipeline Demand Charges</u>

KIUC proposed that the pipeline supplier's demand component of LG&E's G-6 rates be reduced. KIUC opined that G-6 customers, being subject to interruption during the winter, have a lower quality of service than G-1 customers, and that this lower quality of service should be reflected in lower rates. We do not agree.

Rate G-6 customers are subject to interruption for only 90 days during the winter season. LG&E's pipeline demand costs are lower due both to its storage capabilities and the interruptibility of rate G-6 customers.

KIUC presented no evidence or analysis to support its argument. G-6 customers receive firm service for all but 90 days of the year. The quality of their service is not significantly different than that of G-1 customers. In addition, LG&E's lower pipeline demand costs are flowed through to all customers, both firm and interruptible, regardless of whether the lower cost results from LG&E's storage capabilities or the interruptibility of its G-6 customers.

Fuel Adjustment Clause

KIUC proposed that LG&E's electric fuel costs be removed from the base energy charges contained in LG&E's tariffs. KIUC argued that fuel costs should be recovered solely through the operation of the fuel clause and should be shown separately from non-fuel costs.

We disagree. The fuel clause regulation, 807 KAR 5:056, requires the establishment of a level of fuel costs in base rates such that, at the time of setting the base rates, the fuel adjustment factor will be equal to zero.

Tariff Changes

The Commission has addressed a number of specific rate design and tariff changes proposed either by LG&E or the intervenors. Several of the changes proposed by LG&E include text additions, deletions, or revisions which were not challenged by any party. The Commission has reviewed all such changes and finds they should be approved. Due to their voluminous nature, these text changes are not included in the Appendix.

OTHER ISSUES

Management Audit

While the Commission is encouraged by the organizational efficiencies and expected savings described by LG&E concerning its work force, the Commission remains concerned that all aspects supporting LG&E's organization structure are not in place. LG&E has indicated that the restructuring or downsizing dealt primarily with management employees.[140] LG&E has apparently not completed its evaluation of human resources needs and systems, but has begun a process of continuous improvement recognizing that the changes will take time to implement properly.[141] LG&E further indicated that this was the first year that organizational development had been seriously included in LG&E's five year plan and that a manpower planning process was currently being designed for implementation in January 1991.[142]

The Commission fully expects LG&E to pursue in a prompt and expeditious manner the organizational and operational efficiencies described during this proceeding. LG&E's efforts in this area will be monitored by the Commission through the normal management audit follow-up process.

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[140] T.E., Volume II, November 8, 1990, page 126.

[141] Wood Direct Testimony, page 4.

[142] T.E., Volume II, November 8, 1990, page 200.

LG&E also discussed the 4KV conversion program stating that the program was scheduled for completion in approximately the year 2004.[143] Because of the savings estimated by LG&E in an internal study, the Commission encourages LG&E to continue its dialogue with the Management Audit Staff regarding the optimal conversion schedule during the management audit follow-up process.

Energy Conservation Programs

Paddlewheel proposed that the Commission establish a task force to design and administer capacity-avoiding conservation programs for LG&E. Paddlewheel suggested that the task force include LG&E Staff, Commission Staff, traditional intervenors, and conservation experts located in LG&E's service territory. Paddlewheel opined that the Commission, or specifically Commission regulations, have impeded the development of conservation programs in Kentucky. Paddlewheel recommended that the Commission provide utilities incentives for conservation by allowing conservation expenditures to be treated as rate base investments on which a utility can earn a return rather than as operating expenses for which it will be reimbursed. Subsequent to the hearing, Paddlewheel filed a motion requesting the Commission enter an Order formally establishing a task force.

LG&E indicated it was interested in expanding its energy conservation programs and would agree with Paddlewheel that rate base treatment of conservation expenditures would serve as an incentive to encourage utilities to design and implement new

[143] T.E., Volume III, November 9, 1990, page 199.

conservation programs. LG&E also indicated it would like to participate in a collaborative process (task force) to develop new conservation programs.

The Commission endorses the proposal to establish a task force for the purpose of designing and overseeing new conservation programs at LG&E. The Commission is also agreeable to allowing utilities to earn a return on conservation expenditures as an incentive to encourage development of such programs.

The Commission notes that neither at present nor in the past has it had a regulation or policy that acted as a deterrent to utilities making conservation expenditures. In fact, over 9 years ago the Commission stated, "We have in mind an aggressive conservation program, which sees expenditures on conservation not as an unfortunate necessity or misguided effort, but rather as an <u>investment</u>, and as such an alternative to investment in added generating capacity."[144] (emphasis in original) We encourage LG&E and interested intervenors to begin discussion on these matters for the purpose of establishing general goals and establishing a task force, including Commission Staff, to develop new conservation programs for LG&E. However, nothing in Paddlewheel's motion convinces the Commission that there is a present need to order the establishment of such a task force.

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[144] Case No. 8177, General Adjustment of Electric Rates of Kentucky Utilities Company, Order dated September 11, 1981.

Cane Run Unit No. 3 ("Cane Run No. 3")

KIUC and Jefferson et al. recommend that LG&E be prohibited from retiring Cane Run No. 3 until an independent evaluation of the unit could be performed to determine its reliability and possible renovation to extend its active service life. Jefferson et al. also proposed that the Commission establish a process requiring a certificate of decommissioning be obtained by a utility prior to retiring a generating unit. After the hearing in this case, Paddlewheel moved to establish a case in order to investigate the status of Cane Run No. 3.

LG&E agreed that it would not retire, or take any measure to retire, Cane Run No. 3 until an independent evaluation was performed on the unit, either by someone chosen by the Commission or selected by agreement of the company and the intervenors.[145] LG&E did, however, have some questions as to the cost and payment for the evaluation and the time frame within which the study might be performed.

The Commission endorses the proposal agreed to by LG&E that an independent party be selected to perform an evaluation of Cane Run No. 3 prior to its retirement from service. LG&E should begin the process of selecting an independent expert to perform the evaluation. In the event that LG&E and the intervenors are unable to agree on an expert, the Commission will facilitate the selection. The cost, as with any outside service, should be borne by LG&E, with rate recovery at some future point. The Commission

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[145] T.E., Volume I, November 7, 1990, page 167.

would expect the evaluation to be completed prior to the time of LG&E's initial filing under the integrated resource planning regulation in late 1991. The Commission finds no need to establish a case at this time. Accordingly, Paddlewheel's motion will be denied.

Ohio Valley Electric Corporation ("OVEC") Power Agreement

LG&E is one of 15 owners of OVEC, an electric utility which sells power to the Department of Energy ("DOE") under a contract that expires in October 1992. If the DOE contract is not renewed in 1992, the OVEC power reverts to its owners. LG&E would have rights to 165 MW of OVEC capacity if the contract is not renewed.

KIUC recommended that the Commission implore LG&E to take reasonable steps to enhance the usefulness of the OVEC surplus capacity. KIUC proposed that the Commission hold LG&E financially responsible for the OVEC capacity by refusing to allow additional Trimble County capacity, or other capacity, in rate base so long as LG&E's surplus OVEC entitlement results in sufficient capacity to offset the need for additional Trimble County capacity.

LG&E should take reasonable steps to enhance the usefulness of surplus OVEC capacity and all other available capacity, be it through upgrading its hydro capacity or extending the useful life of Cane Run No. 3. All of these planning issues, and any new conservation programs, can be reviewed under the integrated resource planning regulation. As part of that review, and in future rate cases, the Commission will require that LG&E fully explore OVEC capacity, as well as other capacity alternatives, prior to allowing additional Trimble County capacity in rate base.

Reporting for the Holding Company

In the final Order in Case No. 89-374, the Commission indicated that LG&E should provide certain reports to the Commission concerning the activities of the Holding Company. Since the issuance of that Order, LG&E has become a subsidiary of the Holding Company, as was envisioned in the application in Case No. 89-374. The final Order in Case No. 89-374 did not contain a specific date on which LG&E was to begin providing the listed reports. LG&E should begin filing these reports immediately. Reports due annually should begin with calendar year 1990, and reports due quarterly should begin with the quarter ending December 31, 1990. These reports should be filed with the Commission within 30 days after the end of the reporting period.

SUMMARY

After consideration of all matters of record, the evidence, and being otherwise sufficiently advised, the Commission finds that:

1. The rates in the Appendix, attached hereto and incorporated herein, are the fair, just, and reasonable rates for LG&E to charge for service rendered on and after January 1, 1991.

2. The rates proposed by LG&E would produce revenue in excess of that found reasonable herein and should be denied.

IT IS THEREFORE ORDERED that:

1. The rates in the Appendix be and they hereby are approved for service rendered by LG&E on and after January 1, 1991.

2. The rates proposed by LG&E are hereby denied.

3. The tariff changes authorized herein are approved for service rendered on and after January 1, 1991.

4. Paddlewheel's motions to establish cases to designate a conservation task force and to investigate the status of Cane Run No. 3 be and they hereby are denied.

5. Within 30 days from the date of this Order, LG&E shall file with the Commission revised tariff sheets setting out the rate and tariff changes approved herein.

6. Annual reports concerning the Holding Company shall begin with calendar year 1990, while quarterly reports concerning the Holding Company shall begin with the quarter ending December 31, 1990. LG&E shall file these reports 30 days after the end of the reporting period.

Done at Frankfort, Kentucky, this 21st day of December, 1990.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 90-158 DATED 12/21/90

The following rates and charges are prescribed for the customers in the area served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE

RESIDENTIAL RATE (RATE SCHEDULE R)

RATE:

Customer Charge: $3.29 per meter per month

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

First 600 kilowatt-hours per month	5.905¢ per KWH
Additional kilowatt-hours per month	4.584¢ per KWH

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

First 600 kilowatt-hours per month	6.402¢ per KWH
Additional kilowatt-hours per month	6.555¢ per KWH

WATER HEATING RATE (RATE SCHEDULE WH)

RATE:

Customer Charge: $0.93 per meter per month.

All kilowatt-hours per month 4.339¢ per KWH

Minimum Bill: The customer charge.

GENERAL SERVICE RATE
(RATE SCHEDULE GS)

RATE:

Customer Charge:

$3.89 per meter per month for single-phase service
$7.78 per meter per month for three-phase service

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

All kilowatt-hours per month 6.317¢ per KWH

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month 7.102¢ per KWH

SPECIAL RATE FOR ELECTRIC SPACE HEATING SERVICE
RATE SCHEDULE GS

RATE:

Customer Charge: $2.24

For all consumption recorded on the separate meter during the heating season the rate shall be 4.568¢ per kilowatt-hour.

Minimum Bill: The customer charge. This minimum charge is in addition to the regular monthly minimum of Rate GS to which this rider applies.

LARGE COMMERCIAL RATE
(RATE SCHEDULE LC)

RATE:

Customer Charge: $17.09 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution
Winter Rate: (Applicable during 8 monthly billing periods of October through May)		
All kilowatts of billing demand	$7.33 per KW per month	$5.68 per KW per month
Summer Rate: (Applicable during 4 monthly billing periods of June through September)		
All kilowatts of billing demand	$10.43 per KW per month	$8.53 per KW per month

Energy Charge:

All kilowatt-hours per month 3.139¢

LARGE COMMERCIAL TIME-OF-DAY RATE

RATE:

Customer Charge: $18.92 per delivery point per month

Demand Charge:

Basic Demand Charge	
Secondary Distribution	$3.71 per KW per month
Primary Distribution	$2.01 per KW per month
Peak Period Demand Charge	
Summer Peak Period	$6.72 per KW per month
Winter Peak Period	$3.57 per KW per month

Energy Charge: 3.139¢ per KWH

INDUSTRIAL POWER
(RATE SCHEDULE LP)

RATE:

Customer Charge: $42.22 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution	Transmission Line
Winter Rate: (Applicable during 8-monthly billing periods of October through May)			
All kilowatts of billing demand	$8.19 per KW per month	$6.24 per KW per month	$5.03 per KW per month
Summer Rate: (Applicable during 4-monthly billing periods of June through September)			
All kilowatts of billing demand	$10.82 per KW per month	$8.88 per KW per month	$7.66 per KW per month

Energy Charge:

All kilowatt-hours per month 2.716¢ per KWH

INTERRUPTIBLE SERVICE

RATE:

The monthly bill for service under this rider shall be determined in accordance with the provisions of either Rate LC, Rate LC-TOD, Rate LP, or Rate LP-TOD, except there shall be an interruptible demand credit of $3.30 per kilowatt per month.

INDUSTRIAL POWER TIME-OF-DAY RATE
(RATE SCHEDULE LP-TOD)

RATE:

Customer Charge: $44.31 per delivery point per month

Demand Charge:

Basic Demand Charge:	
Secondary Distribution	$5.32 per KW per month
Primary Distribution	$3.34 per KW per month
Transmission Line	$2.13 per KW per month
Peak Period Demand Charge:	
Summer Peak Period	$5.57 per KW per month
Winter Peak Period	$2.96 per KW per month

Energy Charge: 2.708¢ per KWH

OUTDOOR LIGHTING SERVICE
(RATE SCHEDULE OL)

RATE:

	Rate Per Month Per Unit	
	Installed Prior to January 1, 1991	Installed After December 31, 1990
Overhead Service		
Mercury Vapor		
100 watt*	$6.92	$ -0-
175 watt	7.83	9.23
250 watt	8.87	10.32
400 watt	10.80	12.37
1000 watt	19.69	22.32
High Pressure Sodium Vapor		
100 watt	$7.69	$7.69
150 watt	9.84	9.84
250 watt	11.62	11.62
400 watt	12.27	12.27
Underground Service		
Mercury Vapor		
100 Watt - Top Mounted	$12.06	$12.81
175 Watt - Top Mounted	12.83	13.81

High Pressure Sodium Vapor

100 Watt - Top Mounted	$14.19	$14.19
150 Watt	19.33	19.33
250 Watt	22.17	22.17
400 Watt	24.40	24.40

* Restricted to those units in service on 5-31-79.

Special Terms and Conditions:

Company will furnish and install the lighting unit complete with lamp, fixture or luminaire, control device and mast arm. The above rates for overhead service contemplate installation on an existing wood pole with service supplied from overhead circuits only; provided, however, that when possible, floodlights served hereunder may be attached to existing metal street lighting standards supplied from overhead service. If the location of an existing pole is not suitable for the installation of a lighting unit, the Company will extend its secondary conductor one span and install an additional pole for the support of such unit. The customer to pay an additional charge of $1.64 per month for each such pole so installed. If still further poles or conductors are required to extend service to the lighting unit, the customer will be required to make a non-refundable cash advance equal to the installed cost of such further facilities.

PUBLIC STREET LIGHTING SERVICE (RATE SCHEDULE PSL)

RATE:

	Rate Per Month Per Unit	
	Installed Prior to January 1, 1991	Installed After December 31, 1990
Type of Unit		
Overhead Service		
Mercury Vapor		
100 Watt (open bottom fixture)	$6.22	$ -0-
175 Watt	7.28	9.05
250 Watt	8.28	10.15
400 Watt	9.90	12.20
400 Watt (underground pole)	14.31	-0-
1000 Watt	18.39	22.07

High Pressure Sodium Vapor		
150 Watt	8.90	8.90
250 Watt	10.66	10.66
400 Watt	11.10	11.10
Underground Service		
Mercury Vapor		
100 Watt - Top Mounted	10.16	12.55
175 Watt - Top Mounted	11.12	13.63
175 Watt	15.09	21.47
250 Watt	16.12	22.57
400 Watt	18.96	24.62
400 Watt on State of KY Pole	11.21	-0-
High Pressure Sodium Vapor		
100 Watt - Top Mounted	11.17	11.17
150 Watt	19.32	19.32
250 Watt	20.50	20.50
250 Watt on State of KY Pole	10.48	-0-
400 Watt	21.95	21.95
Incandescent		
1500 Lumen	8.29	-0-
6000 Lumen	10.91	-0-

STREET LIGHTING ENERGY RATE
(RATE SCHEDULE SLE)

RATE: $3.972¢ per kilowatt hour

TRAFFIC LIGHTING ENERGY RATE
(RATE SCHEDULE TLE)

RATE:

Customer Charge: $2.45 per meter per month

All kilowatt-hour per month 4.992¢ per KWH

Minimum Bill The customer charge.

SPECIAL CONTRACT FOR ELECTRIC SERVICE
CARBON GRAPHITE SPECIAL CONTRACT

Demand Charge

Primary Power (28,500 KW)	$11.82 per KW per month
Secondary Power (Excess KW)	$5.91 per KW per month
Demand Credit for Primary Interruptible Power (24,500 KW)	$3.30 per KW per month
Energy Charge All KWH	1.946¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
E. I. DUPONT DE NEMOURS SPECIAL CONTRACT

Demand Charge

$11.14 per KW of billing demand per month

Energy Charge

2.012¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
FORT KNOX SPECIAL CONTRACT

Demand Charge

Winter Rate:
(Applicable during 8 monthly billing periods of October through May)

All KW of Billing Demand	$6.32 per KW per month

Summer Rate:
(Applicable during 4 monthly billing periods of June through September)

All KW of Billing Demand	$8.52 per KW per month
Energy Charge: All KWH per month	2.605¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
LOUISVILLE WATER COMPANY SPECIAL CONTRACT

Demand Charge

$7.62 per KW of billing demand per month

Energy Charge

2.138¢ per KWH

GAS SERVICE

The Gas Supply Cost component in the following rates has been adjusted to incorporate all changes through Case No. 10064-J.

GENERAL GAS RATE
G-1

RATE:

Customer Charge:

$4.45 per delivery point per month for residential service
$8.90 per delivery point per month for non-residential service

Charge Per 100 Cubic Feet:

Distribution Cost Component	11.075¢
Gas Supply Cost Component	27.323¢
Total Charge Per 100 Cubic Feet	38.398¢

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE G-1

RATE:

The rate for "Summer Air Conditioning Consumption," as described in the manner hereinafter prescribed, shall be as follows:

Charge Per 100 Cubic Feet:

Distribution Cost Component	6.075¢
Gas Supply Cost Component	27.323¢
Total Charge Per 100 Cubic Feet	33.398¢

GAS TRANSPORTATION SERVICE/STANDBY RATE TS

RATE:

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $90.00 per delivery point per month.

	G-1	G-6
Distribution Charge Per Mcf	$1.1075	$0.5300
Pipeline Supplier's Demand Component	.2032	.2032
Total	$1.3107	$0.7332

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 14
PAGE 1 of 1

Refer to the Kollen Testimony, page 43, line 7.

a. Provide support for the proposed 4 percent debt cost.
b. Provide the most current long term debt rate for 10, 20, and 30 year tenor.

RESPONSE:

Please see attached utility long-term debt yields as published in the Mergent Bond Record, which approximates 3.0% for A/Baa rated utility debt at the end of August. Mr. Kollen proposed 4.0% for this adjustment, subject to true-up through the deferral mechanism that he recommends. The Commission could consider 3.0% in lieu of the proposed 4.0%, but the effect on customers would be the same due to the true-up and the return on the true-up over or under recovery. If, for example, the Commission uses 3.0% for the new debt issue, then the Company would defer the difference in the interest expense between the actual rate of 7.250% and the 3.0% reflected in the revenue requirement from the date base rates are reset through the maturity and redemption date for the maturing issue and then defer the difference in the interest expense between the actual rate and the 3% on the new issue reflected in the revenue requirement until the date base rates are reset in a future base rate proceeding.

Corporate Bond Yield Averages

	AV. CORP.	Corporate by Ratings Aaa	Aa	A	Baa	Corporate by Groups P.U.	IND.	R.R.		Public Utility Bonds Aaa	Aa	A	Baa		Industrial Bonds Aaa	Aa	A	Baa		Railroad Bonds Aaa	Aa	A	Baa
2014																								
Jan.	4.76	4.49	4.53	4.69	5.19	4.72	4.78	----	Jan.	----	4.44	4.63	5.09	Jan.	4.49	4.62	4.74	5.29	Jan.	----	----	----	----
Feb.	4.68	4.45	4.46	4.60	5.10	4.64	4.71	----	Feb.	----	4.38	4.53	5.01	Feb.	4.45	4.54	4.66	5.19	Feb.	----	----	----	----
Mar.	4.65	4.38	4.44	4.56	5.06	4.63	4.65	----	Mar.	----	4.40	4.51	5.00	Mar.	4.38	4.49	4.60	5.13	Mar.	----	----	----	----
Apr.	4.52	4.24	4.33	4.45	4.90	4.52	4.51	----	Apr.	----	4.30	4.41	4.85	Apr.	4.24	4.36	4.48	4.96	Apr.	----	----	----	----
May	4.38	4.16	4.20	4.31	4.76	4.37	4.40	----	May	----	4.16	4.26	4.69	May	4.16	4.24	4.35	4.83	May	----	----	----	----
June	4.44	4.25	4.26	4.35	4.80	4.42	4.45	----	June	----	4.23	4.29	4.73	June	4.25	4.29	4.41	4.86	June	----	----	----	----
July	4.37	4.16	4.20	4.28	4.73	4.35	4.39	----	July	----	4.16	4.23	4.66	July	4.16	4.23	4.34	4.80	July	----	----	----	----
Aug.	4.29	4.08	4.10	4.20	4.69	4.29	4.30	----	Aug.	----	4.07	4.13	4.65	Aug.	4.08	4.13	4.26	4.72	Aug.	----	----	----	----
Sept.	4.39	4.11	4.19	4.30	4.80	4.40	4.37	----	Sept.	----	4.18	4.24	4.79	Sept.	4.11	4.19	4.35	4.82	Sept.	----	----	----	----
Oct.	4.22	3.92	3.99	4.13	4.69	4.24	4.20	----	Oct.	----	3.98	4.06	4.67	Oct.	3.92	4.00	4.20	4.70	Oct.	----	----	----	----
Nov.	4.28	3.92	4.04	4.18	4.79	4.29	4.26	----	Nov.	----	4.03	4.09	4.75	Nov.	3.92	4.04	4.27	4.82	Nov.	----	----	----	----
Dec.	4.17	3.79	3.89	4.05	4.74	4.18	4.15	----	Dec.	----	3.90	3.95	4.70	Dec.	3.79	3.89	4.15	4.77					
2015																								
Jan.	3.84	3.46	3.54	3.70	4.45	3.83	3.84	----	Jan.	----	3.52	3.58	4.39	Jan.	3.46	3.55	3.82	4.51	Jan.	----	----	----	----
Feb.	3.93	3.61	3.64	3.81	4.51	3.91	3.94	----	Feb.	----	3.62	3.67	4.44	Feb.	3.61	3.65	3.94	4.57	Feb.	----	----	----	----
Mar.	3.98	3.64	3.70	3.85	4.54	3.97	3.97	----	Mar.	----	3.67	3.74	4.51	Mar.	3.64	3.72	3.96	4.56	Mar.	----	----	----	----
Apr.	3.93	3.52	3.64	3.82	4.48	3.96	3.88	----	Apr.	----	3.63	3.75	4.51	Apr.	3.52	3.65	3.89	4.45	Apr.	----	----	----	----
May	4.35	3.98	4.07	4.24	4.89	4.38	4.31	----	May	----	4.05	4.17	4.91	May	3.98	4.09	4.30	4.86	May	----	----	----	----
June	4.56	4.19	4.27	4.45	5.13	4.60	4.52	----	June	----	4.29	4.39	5.13	June	4.19	4.25	4.51	5.12	June	----	----	----	----
July	4.57	4.15	4.25	4.44	5.20	4.63	4.51	----	July	----	4.27	4.40	5.22	July	4.15	4.22	4.49	5.18	July	----	----	----	----
Aug.	4.48	4.04	4.13	4.32	5.19	4.54	4.42	----	Aug.	----	4.13	4.25	5.23	Aug.	4.04	4.11	4.39	5.15	Aug.	----	----	----	----
Sept.	4.59	4.07	4.21	4.43	5.34	4.68	4.49	----	Sept.	----	4.25	4.39	5.42	Sept.	4.07	4.16	4.46	5.25	Sept.	----	----	----	----
Oct.	4.52	3.95	4.11	4.33	5.34	4.63	4.40	----	Oct.	----	4.13	4.29	5.47	Oct.	3.95	4.08	4.37	5.21	Oct.	----	----	----	----
Nov.	4.62	4.06	4.21	4.43	5.46	4.73	4.51	----	Nov.	----	4.22	4.40	5.57	Nov.	4.06	4.20	4.45	5.34	Nov.	----	----	----	----
Dec.	4.58	3.97	4.16	4.38	5.46	4.69	4.47	----	Dec.	----	4.16	4.35	5.55	Dec.	3.97	4.16	4.40	5.36	Dec.	----	----	----	----
2016																								
Jan.	4.56	4.00	4.12	4.35	5.45	4.62	4.50	----	Jan.	----	4.09	4.27	5.49	Jan.	4.00	4.16	4.42	5.40	Jan.	----	----	----	----
Feb.	4.44	3.96	3.98	4.22	5.34	4.44	4.43	----	Feb.	----	3.94	4.11	5.28	Feb.	3.96	4.02	4.33	5.39	Feb.	----	----	----	----
Mar.	4.33	3.82	3.91	4.16	5.13	4.40	4.25	----	Mar.	----	3.93	4.16	5.12	Mar.	3.82	3.89	4.16	5.14	Mar.	----	----	----	----
Apr.	4.09	3.62	3.71	3.98	4.79	4.16	4.01	----	Apr.	----	3.74	4.00	4.75	Apr.	3.62	3.67	3.95	4.82	Apr.	----	----	----	----
May	4.04	3.65	3.70	3.94	4.68	4.06	4.02	----	May	----	3.65	3.93	4.60	May	3.65	3.73	3.95	4.75	May	----	----	----	----
June	3.91	3.50	3.60	3.80	4.53	3.93	3.88	----	June	----	3.56	3.78	4.47	June	3.50	3.63	3.82	4.58	June	----	----	----	----
July	3.67	3.28	3.39	3.58	4.22	3.70	3.64	----	July	----	3.36	3.57	4.16	July	3.28	3.42	3.58	4.27	July	----	----	----	----
Aug.	3.70	3.32	3.42	3.60	4.24	3.73	3.66	----	Aug.	----	3.39	3.59	4.20	Aug.	3.32	3.45	3.61	4.27	Aug.	----	----	----	----
Sept.	3.78	3.41	3.50	3.68	4.31	3.80	3.75	----	Sept.	----	3.47	3.66	4.27	Sept.	3.41	3.53	3.69	4.35	Sept.	----	----	----	----
Oct.	3.87	3.51	3.61	3.78	4.38	3.90	3.84	----	Oct.	----	3.59	3.77	4.34	Oct.	3.51	3.63	3.79	4.40	Oct.	----	----	----	----
Nov.	4.20	3.86	3.94	4.11	4.71	4.21	4.19	----	Nov.	----	3.91	4.08	4.64	Nov.	3.86	3.97	4.14	4.77	Nov.	----	----	----	----
Dec.	4.36	4.06	4.12	4.28	4.83	4.39	4.33	----	Dec.	----	4.11	4.27	4.79	Dec.	4.06	4.13	4.29	4.85	Dec.	----	----	----	----
2017																								
Jan.	4.22	3.92	3.98	4.16	4.66	4.24	4.20	----	Jan.	----	3.96	4.14	4.62	Jan.	3.92	4.00	4.17	4.70	Jan.	----	----	----	----
Feb.	4.23	3.95	4.01	4.18	4.64	4.25	4.21	----	Feb.	----	3.99	4.18	4.58	Feb.	3.95	4.02	4.19	4.70	Feb.	----	----	----	----
Mar.	4.28	4.01	4.06	4.23	4.68	4.30	4.27	----	Mar.	----	4.04	4.23	4.62	Mar.	4.01	4.07	4.23	4.74	Mar.	----	----	----	----
Apr.	4.16	3.87	3.93	4.12	4.57	4.19	4.13	----	Apr.	----	3.93	4.12	4.51	Apr.	3.87	3.92	4.11	4.62	Apr.	----	----	----	----
May	4.15	3.85	3.93	4.11	4.55	4.19	4.12	----	May	----	3.94	4.12	4.50	May	3.85	3.92	4.09	4.60	May	----	----	----	----
June	3.98	3.68	3.78	3.93	4.37	4.01	3.95	----	June	----	3.77	3.94	4.32	June	3.68	3.78	3.92	4.41	June	----	----	----	----
July	4.01	3.70	3.80	3.98	4.39	4.06	3.96	----	July	----	3.82	3.99	4.36	July	3.70	3.78	3.95	4.41	July	----	----	----	----
Aug.	3.92	3.63	3.72	3.88	4.31	3.92	3.92	----	Aug.	----	3.67	3.86	4.23	Aug.	3.63	3.76	3.90	4.38	Aug.	----	----	----	----
Sept.	3.92	3.63	3.73	3.88	4.30	3.93	3.91	----	Sept.	----	3.70	3.87	4.24	Sept.	3.63	3.75	3.89	4.37	Sept.	----	----	----	----
Oct.	3.94	3.60	3.75	3.91	4.32	3.97	3.90	----	Oct.	----	3.74	3.91	4.26	Oct.	3.60	3.74	3.90	4.37	Oct.	----	----	----	----
Nov.	3.88	3.57	3.67	3.84	4.27	3.88	3.87	----	Nov.	----	3.65	3.83	4.16	Nov.	3.57	3.68	3.85	4.37	Nov.	----	----	----	----
Dec.	3.83	3.51	3.61	3.79	4.22	3.85	3.80	----	Dec.	----	3.62	3.79	4.14	Dec.	3.51	3.60	3.79	4.31	Dec.	----	----	----	----
2018																								
Jan.	3.88	3.55	3.68	3.85	4.26	3.91	3.85	----	Jan.	----	3.69	3.86	4.18	Jan.	3.55	3.66	3.84	4.33	Jan.	----	----	----	----
Feb.	4.13	3.82	3.95	4.09	4.51	4.15	4.12	----	Feb.	----	3.94	4.09	4.42	Feb.	3.82	3.95	4.09	4.60	Feb.	----	----	----	----
Mar.	4.20	3.87	3.99	4.14	4.64	4.21	4.19	----	Mar.	----	3.97	4.13	4.52	Mar.	3.87	4.00	4.14	4.75	Mar.	----	----	----	----
Apr.	4.22	3.85	4.01	4.17	4.67	4.24	4.20	----	Apr.	----	3.99	4.17	4.58	Apr.	3.85	4.03	4.17	4.76	Apr.	----	----	----	----
May	4.36	4.00	4.12	4.30	4.83	4.36	4.34	----	May	----	4.10	4.28	4.71	May	4.00	4.13	4.31	4.94	May	----	----	----	----
June	4.35	3.96	4.11	4.29	4.83	4.37	4.33	----	June	----	4.11	4.27	4.71	June	3.96	4.11	4.29	4.95	June	----	----	----	----
July	4.31	3.87	4.07	4.26	4.79	4.35	4.26	----	July	----	4.10	4.27	4.67	July	3.87	4.03	4.23	4.91	July	----	----	----	----
Aug.	4.29	3.88	4.05	4.23	4.77	4.33	4.25	----	Aug.	----	4.08	4.26	4.64	Aug.	3.88	4.01	4.20	4.89	Aug.	----	----	----	----
Sept.	4.38	3.98	4.14	4.31	4.88	4.41	4.35	----	Sept.	----	4.18	4.32	4.74	Sept.	3.98	4.09	4.30	5.02	Sept.	----	----	----	----
Oct.	4.54	4.14	4.28	4.46	5.07	4.56	4.52	----	Oct.	----	4.31	4.45	4.91	Oct.	4.14	4.24	4.45	5.22	Oct.	----	----	----	----
Nov.	4.64	4.22	4.37	4.53	5.22	4.65	4.62	----	Nov.	----	4.40	4.52	5.03	Nov.	4.22	4.34	4.53	5.42	Nov.	----	----	----	----
Dec.	4.49	4.02	4.20	4.37	5.13	4.51	4.47	----	Dec.	----	4.24	4.37	4.92	Dec.	4.02	4.16	4.36	5.34	Dec.	----	----	----	----
2019																								
Jan.	4.45	3.93	4.13	4.34	5.12	4.48	4.41	----	Jan.	----	4.18	4.35	4.91	Jan.	3.93	4.07	4.32	5.32	Jan.	----	----	----	----
Feb.	4.31	3.79	3.99	4.23	4.95	4.35	4.27	----	Feb.	----	4.05	4.25	4.76	Feb.	3.79	3.93	4.21	5.13	Feb.	----	----	----	----
Mar.	4.24	3.77	3.92	4.17	4.84	4.26	4.21	----	Mar.	----	3.98	4.16	4.65	Mar.	3.77	3.87	4.17	5.02	Mar.	----	----	----	----
Apr.	4.15	3.69	3.85	4.08	4.70	4.18	4.11	----	Apr.	----	3.91	4.08	4.55	Apr.	3.69	3.79	4.08	4.85	Apr.	----	----	----	----
May	4.08	3.67	3.80	4.01	4.63	4.10	4.06	----	May	----	3.84	3.98	4.47	May	3.67	3.76	4.03	4.78	May	----	----	----	----
June	3.89	3.42	3.59	3.83	4.46	3.93	3.85	----	June	----	3.65	3.82	4.31	June	3.42	3.53	3.84	4.60	June	----	----	----	----
July	3.75	3.29	3.46	3.70	4.28	3.79	3.70	----	July	----	3.53	3.69	4.13	July	3.29	3.38	3.70	4.42	July	----	----	----	----
Aug.	3.36	2.98	3.08	3.32	3.87	3.36	3.36	----	Aug.	----	3.17	3.29	3.63	Aug.	2.98	2.99	3.34	4.11	Aug.	----	----	----	----
Sept.	3.42	3.03	3.14	3.37	3.91	3.44	3.38	----	Sept.	----	3.24	3.37	3.71	Sept.	3.03	3.02	3.35	4.11	Sept.	----	----	----	----
Oct.	3.41	3.01	3.13	3.37	3.93	3.45	3.37	----	Oct.	----	3.24	3.39	3.72	Oct.	3.01	3.01	3.35	4.12	Oct.	----	----	----	----
Nov.	3.44	3.06	3.16	3.40	3.94	3.48	3.40	----	Nov.	----	3.25	3.43	3.76	Nov.	3.06	3.06	3.37	4.12	Nov.	----	----	----	----
Dec.	3.40	3.01	3.11	3.36	3.88	3.45	3.34	----	Dec.	----	3.22	3.40	3.73	Dec.	3.01	3.00	3.32	4.03	Dec.	----	----	----	----
2020																								
Jan.	3.30	2.94	3.02	3.27	3.77	3.34	3.26	----	Jan.	----	3.12	3.29	3.60	Jan.	2.94	2.92	3.24	3.94	Jan.	----	----	----	----
Feb.	3.13	2.78	2.85	3.09	3.61	3.16	3.10	----	Feb.	----	2.96	3.11	3.42	Feb.	2.78	2.75	3.06	3.80	Feb.	----	----	----	----
Mar.	3.53	3.02	3.08	3.43	4.29	3.59	3.46	----	Mar.	----	3.30	3.50	3.96	Mar.	3.02	2.86	3.35	4.61	Mar.	----	----	----	----
Apr.	3.22	2.43	2.75	3.12	4.13	3.31	3.12	----	Apr.	----	2.93	3.19	3.82	Apr.	2.43	2.56	3.05	4.43	Apr.	----	----	----	----
May	3.16	2.49	2.72	3.12	3.95	3.22	3.10	----	May	----	2.89	3.14	3.63	May	2.49	2.55	3.09	4.27	May	----	----	----	----
June	3.02	2.44	2.64	3.02	3.64	3.10	2.93	----	June	----	2.80	3.07	3.44	June	2.44	2.48	2.97	3.84	June	----	----	----	----
July	2.70	2.14	2.32	2.69	3.31	2.77	2.62	----	July	----	2.46	2.74	3.09	July	2.14	2.16	2.63	3.53	July	----	----	----	----
Aug.	2.71	2.25	2.37	2.68	3.27	2.76	2.65	----	Aug.	----	2.49	2.73	3.06	Aug.	2.25	2.25	2.63	3.49	Aug.	----	----	----	----

Notes: Moody's® Long-Term Corporate Bond Yield Averages have been published daily since 1929. They are derived from pricing data on a regularly-replenished population of over 100 seasoned corporate bonds in the US market, each with current outstandings over $100 million. The bonds have maturities as close as possible to 30 years, with an average maturity of 28 years. They are dropped from the list if their remaining life falls below 20 years or if their ratings change. Bonds with deep discounts or steep premiums to par are generally excluded. All yields are yield-to-maturity calculated on a semi-annual compounding basis. Each observation is an unweighted average, with Average Corporate Yields representing the unweighted average of the corresponding Average Industrial and Average Public Utility observations. Because of the dearth of **Aaa** -rated railroad term bond issues, Moody's® **Aaa** railroad bond yield average was discontinued as of December 18, 1967. Moody's® **Aaa** public utility average was suspended from Jan. 1984 thru Sept. 1984. Oct. 1984 figure for last 14 business days only. The Railroad Bond Averages were discontinued as of July 17, 1989 because of insufficient frequently tradable bonds. The July figures were based on 8 business days.
Because of the dearth of Aaa rated public utility bond issues, Moody's® Aaa public utility bond yield average was discontinued as of December 10, 2001.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 15
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Refer to the Kollen Testimony, page 43, lines 12–13. Explain whether the proposed regulatory asset should include a carrying charge, and if so, what rate this carrying charge should be.

RESPONSE:

Yes. The Commission could select a carrying charge ranging from the cost of short-term debt at the low end to the weighted cost of capital at the high end. For example, if the Commission agrees with the Company's proposal to reduce short-term debt first for the Mitchell Coal Stock adjustment, then it would be appropriate to use the cost of short-term debt for this deferral as well under the assumption that the Company uses short-term debt to finance deferrals. If, however, the Commission agrees with the AG and KIUC that the Mitchell Coal Stock adjustment should be made proportionately across the components of the capital structure, then it would be appropriate to use the weighted cost of capital for the deferral. Alternatively, the Commission could select the average cost of long-term debt as an approximate midpoint of the range available for this purpose. The carrying charge should be applied in arrears and on a compounded basis to the deferral net of accumulated deferred income taxes at the end of the prior month.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 16
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Refer to the Kollen Testimony, page 46, lines 13–14. Provide support for the assertion that since the Commission's Order in Case 2017-00179,[11] the economic conditions of Eastern Kentucky have deteriorated further.

RESPONSE:

Refer to Company witness Mr. Mattison's Direct Testimony at 6-7 wherein he describes the economic circumstances in Eastern Kentucky, including the Company's service territory as follows:

> Economic development and retention are important priorities to both Kentucky Power and its customers. As discussed further in Company Witness Wiseman's testimony, the entire eastern Kentucky region, including the Company's service territory, is struggling economically. There is a critical need for the Company to assist with efforts to maintain existing customers and further develop the region's economy.

In addition, refer to Mr. Mattison's Direct Testimony at 10 wherein he describes the economic challenges caused by COVID-19 and how this has worsened the economic situation as follows:

> As I touched on earlier, Kentucky Power fully understands the economic challenges that its customers and the eastern Kentucky region have been facing over the last several years. COVID-19 has only worsened the economic situation. The Governor, the Public Service Commission of Kentucky ("Commission"), and the Company have taken several important steps to mitigate the financial impact of the COVID-19 pandemic on customers, including suspending utility service terminations and ceasing the collection of late payment fees from customers. Despite those efforts, and due to the impacts on business and industry associated with business closures, social distancing, and stay home orders during this public health emergency, a significant number of Kentucky Power's customers have been unable to pay for electric service.

Further, refer to Mr. Mattison's Direct Testimony at 13 wherein he refers to the unique economic and financial challenges facing the Company's customers as follows:

[11] *See* Case No. 2017-00179 *Electronic Application of Kentucky Power Company for (1) a General Adjustment of Its Rates for Electric Service; (2) an Order Approving Its 2017 Environmental Compliance Plan; (3) an Order Approving Its Tariffs and Riders; (4) an Order Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) an Order Granting All Other Required Approvals and Relief*, (Ky. PSC June 28, 2018).

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> Each of these measures represents a one-time proposal that Kentucky Power is making, without prejudice to the Company's positions in future rate cases, in recognition of the unique economic and financial challenges that customers in the Company's service territory are facing as a result of COVID-19.

Finally, refer to Ms. Wiseman's Direct Testimony at 21-22 wherein she describes the declining economic trend in the Company's service territory:

> The primary impact of the downward economic trend is the loss of load and customers. Between 2008 and 2019, Kentucky Power's lost 10,184 customers or approximately 6.4 percent of its total customers. During the same period, the Company has seen its total annual weather normalized sales fall by approximately 23.4 percent from approximately 7.4 GWh to 5.7 GWh.
>
> Furthermore, unemployment and declining economic activity in the entire eastern Kentucky region has resulted in a concomitant population decline in 19 of the 20 counties comprising the Company's service territory.[Footnote omitted] Between 2008 and 2019, population in the Company's service territory has decreased by approximately 33,000 individuals or 7.6 percent. [Footnote omitted] Moreover, the overall unemployment rate in the 20 counties comprising Kentucky Power's service territory is markedly higher than the 4.3 percent unemployment rate for Kentucky as a whole.[Footnote omitted] Unemployment in the Company's service territory ranges from a high of 13.8 percent in Magoffin County to a low of 5.1 percent in Rowan County.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 17
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Refer to the Kollen Testimony, page 49, lines 20–24, through page 52, lines 1–2. Mr. Kollen proposes to extend the depreciation expense for Rockport 2 SCR from three years to ten years, beyond the termination of the Rockport UPA lease. Explain why it is reasonable for future rate payers to pay the depreciation expense associated with an asset for which the future rate payer is not benefiting.

RESPONSE:

Fundamentally, it is not reasonable for customers to pay for the significant capital cost of a new SCR over three years. The three-year depreciation period is due solely to the remaining term of the AEGCo lease with various banks, not the service life of the asset. The SCR has a service life of 20 or more years and would have been depreciated over its service life if AEGCo had not entered into the series of leases on Rockport 2. In the absence of the leases, the Company would have paid only 3/20 of the capital cost during the remaining term of the Rockport UPA, consistent with its usage of the asset.

Mr. Kollen recommends a recovery of the cost of the new SCR over ten years to mitigate the effect on present customers over the next three years, most of whom also will be the future customers over the ten years. The Commission previously approved the deferral of a portion of the Rockport UPA expense for five years while it remains in effect followed by an amortization of the deferrals over five years after it no longer is in effect.

Mr. Kollen's recommendation is consistent with the Commission's decision to defer and amortize in the prior proceeding in order to mitigate and smooth the rate effects of the Rockport UPA through 2022.

Mr. Kollen's recommendation also is consistent with the Commission's decision to defer the remaining net book value of and the decommissioning costs as incurred for Big Sandy 2 and the coal-related assets of Big Sandy 1 and to recover those costs over 25 years after those assets no longer were retired.