COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT IN ELECTRIC)
AND GAS RATES OF LOUISVILLE GAS) CASE No. 8924
AND ELECTRIC COMPANY)

ORDER

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O R D E R

On November 23, 1983, 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 14, 1983. The proposed rates would increase annual electric revenues by $43.5 million, an increase of 10.9 percent, and annual gas revenues by $6 million, an increase of 3.2 percent. These increases represent an annual increase in total operating revenues of $49.5 million, or 7.7 percent, based on normalized test year sales.

The Commission suspended the proposed rate increases until May 14, 1984, in order to conduct public hearings and investigations into the reasonableness of the proposed rates. A hearing was scheduled for March 20, 1984, 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 5:025, Section 7. A hearing to receive public comment and testimony was conducted on March 12, 1984, at the Old Courthouse in Louisville, Kentucky.

Motions to intervene in this matter were filed by the Consumer Protection Division in the Office of the Attorney General ("AG"), the City of Louisville and Jefferson County ("Louisville"), Airco Alloys and Carbide, a division of the BOC Group, Inc., ("Airco"), the Department of Defense of the United States, the Louisville Paddlewheel Alliance ("LPA"), the Office of Kentucky Legal Services Programs on behalf of Sharon Keranick, a residential customer of LG&E, ("Residential Intervenors"), and the group of Arco Metals Company, E. I. dupont de Nemours and Company, Ford Motor Company, Kosmos Cement Company, Rohm and Haas Kentucky, Inc., and Olin Corporation, the Kentucky Industrial Utility Customers ("KIUC"). These motions were granted and no other parties formally intervened.

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 20-23 and 27, 1984, with all parties of record represented. Briefs were filed by April 20, 1984, and the information requested during the hearings has been submitted.

This Order addresses the Commission's findings and determinations on issues presented and disclosed in the hearings and investigation of LG&E's revenue requirements and rate design and provides rates and charges that will produce an increase in annual revenues of $37,828,578.

COMMENTARY

LG&E is a privately-owned electric and gas utility which distributes and sells electricity to approximately 299,500

consumers in Jefferson County, and in portions of Bullitt, Hardin, Meade, Oldham, Shelby and Trimble counties and distributes and sells natural gas to approximately 233,000 consumers in Jefferson County and in portions of 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, 1983, 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 structure, 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 $1,201,196,412. 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. All other elements of the net original cost rate base have been accepted as proposed by LG&E.

Although the Commission has followed its existing policy concerning the calculation of working capital, it intends to monitor the recently-instituted Federal Energy Regulatory Commission ("FERC") rule-making procedure on this matter and investigate its possible application in this jurisdiction. LG&E is hereby put on notice that this issue will be considered in future rate proceedings.

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	$155,082,376	$1,439,731,660	$1,594,814,036
Add:			
Materials & Supplies	$ 1,229,143	$ 50,697,328	$ 51,926,471
Gas Stored Underground	37,290,387	-0-	37,290,387
Prepayments	260,688	494,480	755,168
Cash Working Capital	3,358,590	25,718,398	29,076,988
Sub-total	$ 42,138,808	$ 76,910,206	$ 119,049,014
Deduct:			
Reserve for Depreciation	$ 59,074,135	$ 318,727,118	$ 377,801,253
Customer Advances	1,301,464	802,764	2,104,228
Accumulated Deferred Taxes	14,767,700	114,513,400	129,281,100
Investment Tax Credit (3%)	629,622	1,862,108	2,491,730
Sub-total	$ 75,772,921	$ 435,905,390	$ 511,678,311
Net Original Cost Rate Base	$121,488,263	$1,080,736,476	$1,202,184,739

Capital Structure

LG&E's Controller, Mr. Frank Wilkerson, proposed an adjusted end-of-test-year capital structure containing 45.97 percent debt, 10.03 percent preferred stock, 36.03 percent common equity and 7.97 percent Job Development Investment Tax Credit ("JDIC"). Long-term debt was reduced by $12,000,000 to reflect the retirement, on February 1, 1984, of First Mortgage Bonds and short-term debt was increased by $12,000,000 to fund that retirement. In his supplemental testimony, Mr. Wilkerson stated that LG&E planned to replace $37,000,000 of series E pollution control bonds, in March, 1984, with approximately $26,000,000 of series I pollution control bonds.[1/] The difference would be made up from the balance of unexpended funds from a previous sale of bonds by Jefferson County.[2/] An adjustment to the capital structure was also made to reflect discounts on preferred stock and common equity.

Dr. Carl G. K. Weaver, economist and principal with M. S. Gerber & Associates, Inc., and witness for the AG and Louisville, proposed a capital structure containing 45.97 percent debt, 10.12 percent preferred stock, 35.94 percent common equity and 7.97 percent JDIC. The difference between Dr. Weaver's proposed capital structure and Mr. Wilkerson's was in the adjustment to reflect discounts on preferred stock and common equity.[3/]

At the hearing, Mr. Wilkerson was asked to file an update of his Exhibit S, showing LG&E's capital ratios as of February 29, 1984. According to that updated exhibit, LG&E's capital structure contained 44.99 percent debt, 9.97 percent preferred stock, 36.84

percent common equity and 8.20 percent JDIC. This capital structure reflects additional retained earnings and additional common stock from LG&E's dividend reinvestment plan and employee stock plan. Furthermore, the additional $12,000,000 of short-term debt, required to fund the retirement of First Mortgage Bonds, was not required because the funds became available from other sources.[4/] The Commission is of the opinion that the adjustments to the end-of-test-year capital structure proposed by LG&E are known, measurable and reasonable. They reflect actual changes in LG&E's end-of-test-year capital structure. Therefore, the Commission is of the opinion that an adjusted capital structure containing 49.01 percent debt, 10.86 percent preferred stock and 40.13 percent common equity is reasonable.

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

	Amount	Percent
Debt	$ 571,841,013	49.01
Preferred Stock	126,712,781	10.86
Common Stock	468,230,563	40.13
Total	$1,166,784,357	100.00

In determining the capital structure the Commission has accepted the capital ratios reflected as of February 29, 1984. However, in accordance with its standard rate-making procedures, the amount of total capitalization has not been increased beyond the test-year-end balance. The test-year-end JDIC has been allocated to each component of the capital structure on the basis of the ratio of each component to total capital excluding JDIC. The

Commission is of the opinion that this treatment is entirely consistent with the requirement of the Internal Revenue Service ("IRS") 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 Wilkerson 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 $2,365,629,578 which includes electric facilities of $2,019,662,337 and gas facilities of $345,967,241.

REVENUES AND EXPENSES

For the test period LG&E had net operating income of $95,602,933. LG&E 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 $105,171,299.[5] 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 - Gas Rates

LG&E proposed adjustments to gas revenues and expenses to normalize for abnormal temperatures experienced during the test year. LG&E's proposal would increase operating income by $1,974,701 based on the assumption that test year sales were 1,837,056 Mcf below normal due to the milder-than-normal temperatures experienced during the test year. LG&E's witness, Mr. John

Hart, Jr., Vice President for Rates and Economic Research, calculated the adjustment by determining the level of space heating sales during the test year and computing the number of space heating Mcf per heating degree day for the four rate classes which reflect temperature-sensitive sales.[6] To determine the deficit in Mcf sales, Mr. Hart applied the levels of Mcf per degree day to the degree day deficiency experienced during the test year. The sales deficit was then converted to revenue by applying the price per Mcf during the period of degree day deficiency to the Mcf sales deficit. The expense adjustment was calculated by applying the purchased gas commodity rate during the period of degree day deficiency to the Mcf deficit.

Dr. Mark Gerber, of M. S. Gerber and Associates, Inc., witness for the AG and Louisville, disputed the adjustment proposed by LG&E and proposed an alternative adjustment which would increase operating income by $3,530,000.[7] Dr. Gerber contends that the data used in LG&E's adjustment are inconsistent with each other in that the Mcf sales and heating degree days reflect the entire test year while the gas prices and commodity costs are taken from the 6 months when heating degree days were less than normal. Dr. Gerber also maintains that LG&E is incorrect in including sales from the entire test year in its adjustment because during the months outside the 6-month heating season--from October through March--sales response to temperature is less and this results in biasing the adjustment in a downward direction. Dr. Gerber claims that by including sales from the entire test year in its adjustment LG&E has assumed that the response of

sales to temperature is linear when in fact sales are a non-linear function of temperature. Dr. Gerber attempted to adjust for the problems he perceived with LG&E's adjustment by applying Mr. Hart's methodology to the sales data from the 6 months of October through March and excluding the sales from the remainder of the test year.

The Commission agrees with Dr. Gerber, in part, and is of the opinion that LG&E's adjustment could be improved to present a better indication of the response of sales to temperature at different times of the year under various weather conditions. However, the Commission is not persuaded by Dr. Gerber's argument that limiting the adjustment to 6 months' data results in a better measurement of sales response to temperature. As Mr. Hart stated under cross-examination, the use of the entire 12 months results in averaging the various responses of sales to temperature that occur throughout the test year and does not reflect a linear relationship between sales and temperature.[8/] Furthermore, Dr. Gerber's adjustment ignores months, such as April and May, in which the response of sales to temperature was significant.

The Commission questions the inconsistency of LG&E's proposal, i.e., using 12-month sales volumes and 6-month average prices, and it also questions the reasons for the different results achieved using 12-month average prices versus 6-month prices. The Commission intends to address these questions in LG&E's future rate proceedings; however, until these questions are addressed, LG&E's adjustment will be accepted as in prior cases.

Temperature Normalization - Electric Sales

LG&E did not propose a temperature normalization adjustment for electric sales primarily because the Commission has disallowed such adjustments in prior cases and because the effects of such an adjustment for the test year ended August 31, 1983, would have been minimal.[9/]

Mr. Stephen J. Baron, of Kennedy and Associates, witness for Airco, questioned the representativeness, for rate-making purposes, of the test year ended August 31, 1983, and recommended that test period revenues and expenses be weather normalized to establish a representative test year.[10/] Mr. Baron formulated this recommendation after making a comparison of the August 31, 1983, test year and the 12-month period ending September 30, 1983. Contrary to Mr. Baron's conclusion, the results of this comparison show only that LG&E's operating results during its proposed test year were different from the operating results of the 12 months ended September 30, 1983. A further review of LG&E's monthly reports and annual reports shows that the August test year closely approximated historical averages for residential sales, average sales per consumer and annual cooling degree days.

The Commission has denied electric temperature normalization adjustments in LG&E's two most recent rate cases. In this proceeding, Mr. Baron has not shown there to be a need for such an adjustment in this case based upon his analysis of the test year. Therefore, the Commission will not require any temperature normalization of LG&E's electric sales for the test year ended August 31, 1983.

The Commission wishes to emphasize that the decision to reject Mr. Baron's proposal is not a rejection of the general concept of normalization. As stated in previous discussions of this subject, the Commission endorses the concept of normalization and is not adverse to considering such proposals further when presented in future rate proceedings.

Hydro License Fee

LG&E proposed an adjustment of $4,771,333 to reflect the increase in the annual fee it pays the federal government for the use of the McAlpine Dam for the operation of its hydroelectric generating plant. Historically, the fee has been imposed by the FERC at a rate of $95,000 per year. The current FERC licensing proceeding would increase the fee to a maximum of $2,621,000 annually which would be retroactive to September 1981, the effective date of the new license.

LG&E proposed its adjustment to reflect the prospective recovery of the increased annual fee plus the 3-year amortization and recovery of the amount accrued from September 1, 1981, through April 30, 1984. LG&E indicated that the period of amortization was less important than the establishment of a mechanism to recover the retroactive portion of the increased fee.[11/] In addition to the FERC proceeding Congress has pending before it legislation which includes an alternative to the FERC proposal that would result in a $300,000 annual fee for LG&E. Also, LG&E has filed with the United States Court of Appeals for certain

relief from the FERC proposal. Either of these matters could affect the amount by which LG&E's license fee ultimately increases.

Mr. Baron questioned the appropriateness of permitting an expense in current rates which is subject to such a high degree of uncertainty.[12] However, he indicated that LG&E should be allowed a full recovery of the increased fee, including the retroactive portion, when a final ruling is made on the amount of the fee.[13]

The AG contends that any recovery of the increased license fee expense for the time period prior to the issuance of this Order would constitute retroactive rate-making and be unlawful.[14] However, the AG recommends that the Commission adopt a mechanism to allow the recovery of any prospective expense after the FERC's final order is issued.[15]

The Commission is of the opinion that the full amount of the increased fee will be recoverable through rates once a final determination is made as to the exact amount of the fee. Such recovery is not retroactive rate-making because ratepayers will not be required to pay for past losses but rather for a future expense, the amount of which is not yet known and measurable. Since the amount of the increased fee is as yet unknown the Commission has made no adjustment at this time to reflect this expense for rate-making purposes. However, once the amount is determined LG&E will be allowed to recover the increased fee through an approved surcharge. Had the final amount of the increased fee been determined, known and measurable as of September 1981, LG&E would have incurred the increased expense over the

30-year life of the new license. The Commission is of the opinion that the rate-making treatment which would most nearly approximate that ideal determination would result from an amortization period equal to the remaining life of the license. Therefore, LG&E should file its proposed surcharge under this docket with a proposed amortization period equal to the remaining life of the license at the time of the filing.

Wages and Salaries

In its original application LG&E proposed an adjustment of $1,280,490 to normalize wage and salary expenses to the test-year-end level. These expense levels included wage and salary increases the Commission disallowed for rate-making purposes in Case No. 8616, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, LG&E's most recent rate case.

In Case No. 8616, the Commission modified LG&E's proposed wage and salary adjustment to reduce or exclude for rate-making purposes those wage and salary increases it found to be excessive. LG&E now contends that, with the passage of 1 1/2 years since the date of those wage increases and the increase in the cost of living during that period of time, these 1982 wage increases are clearly justified for inclusion in the determination of rates to be in effect from this point forward.[16/]

The Commission is of the opinion that it was proper to modify the adjustments proposed by LG&E in Case No. 8616; however, considering the passage of time and the increases in the cost of

living, the Commission is of the opinion that the inclusion of such costs in the determination of revenue requirements is appropriate in this proceeding.

On March 14, 1984, LG&E filed a supplemental adjustment to reflect the 4 percent wage increase for union employees effective February 3, 1984, in the amount of $1,649,463. This increase went into effect more than 5 months beyond the end of the test year. In filing this supplemental adjustment, less than 1 week prior to the hearing of this case, LG&E did not increase its requested revenues but asked that the the Commission consider this adjustment in determining revenue requirements.[17/]

Mr. Robert L. Royer, LG&E's president and chief executive officer, stated that the new union contract incorporated several changes which will result in more efficient and effective administration of the non-economic provisions of the contract.[18/] Mr. Royer testified that any cost reductions resulting from these changes would develop over time and be reflected in future test year costs but could not be quantified at this time.[19/]

Supplemental adjustments such as this, submitted late in the proceeding, are becoming more and more frequent. Generally, these adjustments reflect an addition to expenses without a request for additional revenues to cover these expenses. It is fairly apparent that additional revenues are not requested because such a request would necessitate the filing of new rate schedules and would result in a new 5-month suspension period being imposed. In situations such as this, when additional revenues are not

requested, the Commission and intervenors are both at a disadvantage in attempting to analyze these adjustments. Intervenors, particularly those with limited funding, can be hard-pressed to evaluate such adjustments without incurring additional expense for consultants and expert witnesses. Filings such as this also raise the question of whether intervenors are being afforded due process in these matters.

The Commission is of the opinion that the supplemental adjustment proposed by LG&E is incomplete in that it reflects the increased costs associated with the new contract without attempting to recognize or quantify the associated efficiencies and cost reductions. Proper matching would require that these cost reductions and efficiencies associated with the new contract be afforded similar rate-making treatment. Inasmuch as the efficiencies and cost reductions associated with the new contract will not be recognized for rate-making purposes until future test years, the Commission is of the opinion that recognition of the increased costs associated with the contract should also be deferred until future test years. Furthermore, LG&E's decision not to increase its requested revenues by the amount of the supplemental adjustment prevents the Commission from giving the adjustment any affirmative consideration. Therefore, the Commission has accepted LG&E's original adjustment, which normalizes wages and salaries to the end of the test year but has denied its supplemental wage adjustment.

Fringe Benefits

LG&E proposed an adjustment of $936,497 to normalize its expense for fringe benefits to the test-year-end level and reflect projected increases for insurance and social security rates scheduled to increase on January 1, 1984. The actual increases for Major Medical and Blue Cross-Blue Shield health insurance differed slightly from LG&E's original projections resulting in an additional expense of $49,508.[20] Therefore, LG&E's adjustment has been increased to $986,005 to reflect the increase in insurance costs. The Commission is aware that the record in this proceeding reflects little interest in this matter. However, taking notice of the $558,000 increase in LG&E's expense for Blue Cross-Blue Shield insurance for 1984, the Commission intends to analyze this matter in LG&E's next rate case. LG&E should be prepared to show that it is attempting to control these costs as much as possible.

In accordance with the decision to disallow LG&E's supplemental wage adjustment, the Commission has not accepted the related adjustment which would increase the expense for social security taxes by $115,462.

Expense of Consultant's Study

In Case No. 8616 the Commission found that the cost to be incurred by LG&E for a forecasting and planning study by Energy Systems Research Group, Inc., ("ESRG") would be fully recoverable through rates. During the test year LG&E's expense for the ESRG study was $6,963 and its total cost was originally established at $42,103. Therefore, LG&E proposed an adjustment of $35,140 to

reflect the full cost in rates. The cost to LG&E has subsequently increased to $58,298 due to changes in the provisions of the study. The Commission is of the opinion that this will not be an annually recurring expense and, therefore, should be amortized over a period of 2 years for rate-making purposes. Therefore, the Commission has made an adjustment of $25,668 to reflect LG&E's increased cost for rate-making purposes.

Gas Costs

LG&E did not propose an adjustment to the cost of gas included in revenue requirements. However, Mr. Hart testified to the gas cost component of the proposed base rates, which he calculated to be $3.8034 per Mcf sendout or $187,609,110.[21/] The method used to calculate this gas cost was substantially the same as that used by Mr. Hart in Case No. 8616 and used by Mr. Randall Walker, LG&E's Coordinator of Rates & Tariffs, in Case No. 8284, LG&E's rate case prior to Case No. 8616, on the subject of profits on the sale of gas from storage. Additionally, the adjusted revenue at present and proposed rates includes ($3,543,136) from purchased gas adjustment ("PGA") billings.[22/] The sum of these two accounts, $184,065,974, represents the total gas cost reflected in the adjusted revenue from both proposed base rates and PGA billings. Mr. Hart argued that the PGA billings can not be used in such a calculation unless they are increased to eliminate $406,135 interest credited to customers on refundable amounts.[23/] However, this interest is an offset to the benefit that LG&E received from the use of the refundable amounts and should be excluded from revenue requirements. Using the PGA

billings included in the adjusted revenue, with no further adjustment, for calculating the total gas cost reflected in the adjusted revenue results in excluding interest on customer refunds from the revenue requirement. Gas supply expense per books for the test year was $184,423,161. Therefore, the Commission is of the opinion that gas operating expenses should be adjusted downward by $357,187[24/] to reflect the gas cost component of proposed base rates that would allow for the lower cost of gas withdrawn from storage.

The major expense for LG&E gas operations is gas supply expense, constituting 83.5 percent of test year actual operating expenses. The Commission has for many years allowed recovery of changes in gas supply costs through the expedited proceedings of the PGA clause. However, Mr. Hart, who is responsible for LG&E's PGA filings, does not know if recovery of gas costs, through the gas cost component of base rates, plus the PGA, significantly exceeded or fell short of test year actual gas cost.[25/] In recent years other gas utilities in Kentucky have proposed and the Commission has approved PGA clauses that track and bill over- and under-recoveries of gas costs. Mr. Hart said that LG&E's significant storage operation complicates the calculation of an over- or under-recovery and that he did not see the significance of such a calculation.[26/] Given the size of gas supply costs and the expedited recovery of cost changes through the PGA clause, the Commission and ratepayers must be assured both that gas utilities are securing gas supplies at the lowest possible cost and that rate-making treatment allows recovery and not over-recovery of

those costs. Although the accounting problems mentioned by Mr. Hart may be challenging, the Commission finds that LG&E should meet that challenge and file no later than September 1, 1984, proposed revisions of its PGA clause and rate case treatment of gas costs that will provide for ongoing determination and billing of material over- and under-recoveries of gas costs.

Interest Synchronization

LG&E disagrees with the Commission's historical treatment of JDIC as it relates to interest expense. Mr. Wilkerson questioned the Commission's practice of imputing interest expense for the portion of JDIC assigned to the debt components of the capital structure and treating the interest as a deduction in computing federal income tax expense allowed in the cost of service.[27/]

LG&E is but one of several utilities which have disagreed with this rate-making treatment in recent years. One of these, Continental Telephone Company ("Continental"), has had two cases on appeal in the Kentucky Court of Appeals under Docket Nos. 82-CA-2657-MR and 83-CA-431-MR in which one of the issues was the Commission's treatment of JDIC. On April 13, 1984, the Court of Appeals issued contradictory opinions in the two cases and directed that the matter be pursued in the State Supreme Court. Not expecting contradictory opinions from the Court of Appeals, the Commission had reserved this matter in other cases pending the appellate court's final decision. The initial case in which such action was taken was Case No. 8734, Adjustment of Rates of Kentucky Power Company.[28/] In that proceeding, at the request of Kentucky Power Company to avoid any additional judicial review on

this issue, the Commission stated that should the final judicial opinion in the Continental cases be adverse to the Commission's position, it would then consider a rate adjustment to generate the revenues associated with the debt component of JDIC.

The Commission continues to be of the opinion that its past treatment of JDIC is proper and consistent with IRS regulations and such treatment will be continued in this proceeding. However, as in Case No. 8734, the provisions of this Order should eliminate the need for appeal of this matter at the judicial level. Therefore, LG&E is hereby apprised that should the final judicial opinion in the case(s) of Continental be adverse to the Commission's position on interest associated with JDIC, it will then consider a rate adjustment to generate the associated revenues which have been denied herein.

At this time, in accordance with past practice, the Commission has applied the cost rates applicable to long-term debt and short-term debt to the JDIC allocated to the debt components of the capital structure. Using the adjusted capital structure allowed herein, the Commission has computed an interest adjustment of $2,772,427 which results in a reduction to income taxes of $1,365,143.

After applying the combined state and federal income tax rate of 49.24 percent to the accepted pro forma adjustments, the Commission finds that combined operating income should be increased by $13,334,455 to $108,937,388.

The adjusted net operating income is as follows:

	Gas	Electric	Total
Operating Revenues	$240,561,073	$400,588,035	$641,149,108
Operating Expenses	230,265,684	301,946,036	532,211,720
Net Operating Income	$ 10,295,389	$ 98,641,999	$108,937,388

RATE OF RETURN

Cost of Debt

Mr. Wilkerson proposed a cost of 8.09 percent for preferred stock, that was based on the dividend rate times the amount sold.[29/] Dr. Weaver also used an 8.09 percent cost for preferred stock in his testimony. However, the Commission is of the opinion that the cost for preferred stock should be based on the amount outstanding times the cost rate at issuance. Therefore, the Commission is of the opinion that a cost of 8.06 percent for preferred stock is reasonable.

In his prefiled testimony, Mr. Wilkerson proposed an embedded cost for long-term debt of 8.32 percent. However, in response to a staff information request at the hearing, Mr. Wilkerson revised the embedded cost of long-term debt to reflect the replacement of $37,000,000 of series E pollution control bonds with less costly series I pollution control bonds.[30/] The revised embedded cost of long-term debt is 8.22 percent. Mr. Wilkerson also proposed a 9.87 percent cost for short-term debt, based on the borrowing rates at the end of the test year. Dr. Weaver proposed an 8.46 percent composite of cost of debt which included an 8.32 percent embedded cost of long-term debt and a 9.87 percent cost

for short-term debt.[31] Given the recommendations of Mr. Wilkerson and Dr. Weaver and the current trend in interest rates, the Commission is of the opinion that a composite cost of debt of 8.34 percent is reasonable. This composite cost includes an 8.22 percent embedded cost of long-term debt and a 9.87 percent cost of short-term debt.

Cost of Equity

Mr. Wayne D. Monteau, Senior Vice President for H. Zinder & Associates and witness for LG&E, recommended a return on equity in the range of 15.25 to 15.75 percent, based on a risk premium analysis and a comparable earnings analysis. He concluded that LG&E is currently, and has for some time been, earning an inadequate return on equity.[32] Mr. Monteau calculated the cost of common equity for the 93 electric utilities listed on the New York Stock Exchange ("NYSE") based on a discounted cash flow ("DCF") model. He then compared the calculated cost of equity to Moody's index of utility bond yields and developed risk premiums for the years 1975 through 1982 and the 8 months ended August 31, 1983. Mr. Monteau then determined a 15.74 percent cost of common equity for LG&E by adding the average risk premium he developed to LG&E's average bond yield.[33]

Mr. Monteau also performed a comparable earnings analysis to determine the relative risk and required return of LG&E. He compared the financial statistics of LG&E to those of 30 electric utilities he selected. Based on the comparable earnings analysis,

Mr. Monteau concluded that the comparison utilities were earning substantially more than LG&E on thicker common equity participation.[34/]

Mr. Monteau did not perform a DCF analysis for LG&E nor his 30 comparable electric utilities, although market data were available. He did perform a DCF analysis for the 93 NYSE electrics (as part of a risk premium analysis) but that group is very diverse and many of the companies are dissimilar to LG&E. The Commission has reservations regarding Mr. Monteau's risk premium analysis. Debt and equity may not react equally to changes in the financial markets, resulting in an unstable risk premium. The Commission is not convinced that an ex-ante risk premium can be accurately determined from historical data. Furthermore, using an estimate of the cost of common equity for the 93 NYSE electrics in the risk premium analysis could produce further distortions of the ex-ante risk premium applicable to LG&E.

The Commission also has reservations regarding the 30 electric utilities selected by Mr. Monteau for a comparable earnings analysis. Over half of the companies are involved in nuclear generation.[35/] Although Mr. Monteau did not necessarily agree, the Commission is of the opinion that involvement with nuclear generation can increase the risk investors associate with a utility.[36/] Certainly involvement with nuclear generation has increased the risk of utilities such as General Public Utilities (owners of Three Mile Island). Given the large proportion of

electric utilities involved with nuclear generation, the Commission is not convinced that Mr. Monteau's 30 comparable companies are in fact comparable to LG&E in terms of risk.

Mr. Peter Ronald, Senior Vice President of Finance and Treasurer of LG&E and witness for LG&E, did not specifically make a recommendation as to the appropriate return on common equity for LG&E. However, he believed that LG&E needed to earn a higher rate of return to maintain its financial integrity.[37/] Mr. Ronald stated that market value should be at least 10 percent over book value to allow LG&E to issue stock without dilution.[38/] Therefore, a higher return on equity was required for LG&E. The Commission is of the opinion that granting a rate of return sufficient to ensure a market value at least 10 percent in excess of book value might overstate the actual investor required return on equity. LG&E's average selling expense for common equity was only 3.28 percent and market fluctuations caused by the issuance of common stock can be positive as well as negative.[39/] Furthermore, the Commission should not set rates to guarantee that the market value of LG&E's common stock exceeds its book value at any given time. Currently, LG&E's market to book ratio is in excess of one.

Dr. Weaver recommended a cost of common equity for LG&E in the range of 13 to 14 percent, based primarily on a DCF analysis. He performed a DCF analysis on LG&E and on a group of three comparison companies, using 1983 data and historical data. Dr. Weaver developed his growth rates using the earnings retention ratio times the return on equity ("bxr") method. Dr. Weaver believed the cost of common equity for LG&E was less than the cost

of common equity for the three comparison companies because LG&E has 100 percent CWIP in its rate base which improves LG&E's ability to generate funds internally.[40]

The Commission is of the opinion that Dr. Weaver's DCF analysis could understate the actual investor-required return on equity for LG&E. The bxr method can understate the growth rate component in the DCF analysis if earnings have been inadequate in the past. The lower growth rate derived from the bxr 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 cycle can develop that could weaken the financial integrity of LG&E. Dr. Weaver did not consider any other growth estimates. However, according to Value Line, the expected growth rate in earnings per share was 3.5 percent.[41] Using the higher Value Line growth rate in Dr. Weaver's DCF analysis would result in a higher return on equity for LG&E.

Mr. David H. Kinloch, witness for LPA, stated that LG&E's rate of return should be lowered because of the inclusion of 100 percent of CWIP in its rate base.[42]

The Commission is obligated to allow LG&E an opportunity to earn a return that is adequate to maintain its financial integrity. LG&E is allowed to earn a cash return on 100 percent of CWIP and its capital ratios are within the target ranges mentioned by Mr. Ronald.[43] Currently, LG&E's market to book ratio is in excess of one which tends to indicate that investors perceive LG&E's return on equity to be adequate. However, capital costs have been rising, with Moody's AA rated utility bonds yielding

almost 14 percent recently.[44] Therefore, after considering all of the evidence, including current economic conditions, the Commission is of the opinion that a return on common equity in the range of 14.5 to 15.5 percent is fair just and reasonable. A return on equity in this range would not only allow LG&E to attract capital at reasonable costs to insure continued service and provide for necessary expansion to meet future requirements, but also would result in the lowest possible cost to the ratepayer. A return on equity of 15 percent will best meet the above objectives.

Rate of Return Summary

Applying rates of 8.34 percent for debt, 8.06 percent for preferred stock and 15 percent for common equity to the capital structure approved herein produces an overall cost of capital of 10.98 percent. The additional revenue granted herein will provide a rate of return on net investment of 10.66 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 $19,201,786 to produce a rate of return of 15 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 $37,828,578 which is the amount of additional revenue granted herein. The net operating income required to allow LG&E the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity

growth is $128,139,174. A breakdown between gas and electric operations of the required operating income and the increase in revenue allowed herein is as follows:

	Total	Electric	Gas
Net Operating Income Found Reasonable	$128,139,174	$115,197,117	$12,942,057
Adjusted Net Operating Income	$108,937,388	$ 98,641,999	$10,295,389
Net Operating Income Deficiency	$ 19,201,786	$ 16,555,118	$ 2,646,668
Additional Revenue Required	$ 37,828,578	$32,614,496	$ 5,214,082

The additional revenue granted herein will provide a rate of return on the net original cost rate base of 10.66 percent and an overall return on total capitalization of 10.98 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $669,958,991. These operating revenues include $433,202,531 in electric revenues and $236,756,460 in gas revenues. The gas revenues reflect a reduction of $9,018,695 due to the PGAs approved since LG&E's last general rate case.

OTHER ISSUES

Trimble County CWIP

The most difficult issue in this case is the treatment of CWIP and whether or not ratepayers should be required to pay a return now on plant that is being built, but is not yet in service. The alternatives are to pay it now, or to have LG&E accrue the financing costs and include the accrued financing cost

in the investment in the plant. The second alternative means that there will be a larger investment on which a return will be required when the plant is finished. In addition, there will be depreciation and property taxes on the larger amount.

There are various arguments pro and con on this issue. In support of disallowing a current return by accruing an Allowance for Funds Used During Construction ("AFUDC") is the argument that those who actually receive power from the plant should pay all of the costs of constructing the plant, including the financing cost. This made very good sense in the past when the cost of power from new plants was no larger than, or even lower than, the costs from present plants, as more efficient plants were built at a time of very low inflation. The reality now is that power from any new plant is going to be a great deal more expensive than power from any existing plant. Therefore, accruing AFUDC leads to very abrupt increases in rates at the time when a plant goes into service. We are seeing this in two cases pending before the Commission, in which this accounting treatment was the basis for anticipated increases of nearly 40 percent. It also is very difficult to sort out present customers from future customers. It is primarily the use of electricity by present customers that is the justification for building new plants. It is not as if a group of customers suddenly arrived in the area and required electric power. In that case, accruing AFUDC would make very good sense.

LG&E has never accrued AFUDC. This means that the present ratepayers are paying less because of financing costs paid by

prior ratepayers. It has also been contended that LG&E's cost of money has been lower because of this treatment. The argument here is that stockholders would rather have a current cash return than a possible future cash return--would rather have cash earnings than the bookkeeping earnings represented by AFUDC. In the past, these have been referred to as "funny money." For some utilities, with massive construction programs, the AFUDC paper earnings have amounted to 50, 60, and even 90 percent of their reported earnings. For companies who do not accrue AFUDC, the reported earnings represent cash earnings. LG&E, in some respects, has tried to have it both ways on this issue, arguing that it should be allowed a present return on CWIP, but at the same time arguing that it does not really affect its cost of money.

In this instance, the ratepayers today could be benefited if the Commission were to decide that beginning with this Order, no current return would be allowed on CWIP. They would then not be paying the financing costs of existing plants presently generating power, because it was paid by the ratepayers when those plants were built, and would not be paying the financing cost on the plant being built today, because it would be pushed to the future. However, the ratepayers would experience an increase of a substantial magnitude when the plant was finished. It would, in effect, be a one-time benefit, with costs to be borne later.

There are also arguments that such a shift would be beneficial to LG&E. One of LG&E's arguments was that under the Commission's present treatment, where rate base, including CWIP, is based on a historical test year, substantial portions of the

financing costs of new plants are never recovered. This has undoubtedly contributed to LG&E's failure to earn its authorized rate of return in recent years, because the rate base has accelerated rapidly during the period from the end of the test year to the date of the Order, and then has continued to accelerate. In fact, a substantial portion of this application is due to this very factor. With AFUDC accrual, LG&E would automatically have accounting earnings to report to correspond to whatever balance was in the CWIP plant accounts, and would be allowed to recover this over the life of the plant as depreciation. LG&E would further earn a return on the undepreciated portion once the plant was in service. Mr. Jay Price, LG&E's rebuttal witness, was not sure why LG&E has insisted on a cash return on CWIP rather than AFUDC.[45/]

In this case the AG, Louisville and Airco each presented witnesses with proposals to require LG&E to accrue AFUDC on a portion, but not all, of its investment in the Trimble County Generating Unit No. 1 ("Trimble County"). The AG, through Dr. Weaver, recommended an approach that would require accruing AFUDC on the equity component of the year-end Trimble County CWIP of $267 million. This approach would result in a reduction of approximately $20 million in LG&E's revenue requirements.[46/] Louisville, through its witness, Mr. Thomas J. Flaherty of Touche Ross and Company, recommended allowing a cash return on that portion of the year-end CWIP balance considered necessary to maintain LG&E's financial integrity. Louisville made no recommendation as to a specific level of CWIP which should earn a cash return since the

amount would be determined by the allowed rate of return, according to Mr. Flaherty.[47/] Airco, through its witness, Mr. Randall J. Falkenberg, of Kennedy and Associates, recommended that LG&E accrue AFUDC on the excess of the Trimble County investment over the $190 million cost for a similar amount of combustion turbine capacity. Mr. Falkenberg calculated a revenue requirement reduction of approximately $16 million using this approach.[48/]

Mr. Flaherty testified that his recommendation was not dependent upon Trimble County's construction schedule but was, in his opinion, the way to best serve the interest of both the ratepayer and the utility by sharing the risks associated with the construction project.[49/] Both Dr. Weaver and Mr. Falkenberg premised their recommendations on uncertainties about the construction schedule and eventual completion of Trimble County. There are either practical or theoretical problems with each of their approaches.

The uncertainty about the future of the Trimble County plant adds to the confusion surrounding this issue. If the plant is delayed for several years, then accruing AFUDC would make the final cost of the plant even higher. If, on the other hand, the plant is finally cancelled, the total investment, including the accrued AFUDC will have to be dealt with. The Commission does not have that issue before it at this time, but does note that in several other jurisdictions where plants have been cancelled, the consumers have ended up bearing at least the investment under various amortization schemes.[50/] If the plant were to be cancelled,

the amount on which amortization would have to be considered would be even larger.

At least one witness has argued that paying a current return encourages the company to not make a decision. On the other hand, it could be argued that accruing AFUDC would postpone the day of reckoning, because the company would begin to accrue accounting earnings on all investment to date, not just the amount as of the end of the test year. Under that treatment, LG&E would not have to file rate cases to recover a return on the additional investment, and therefore could basically keep the matter out of the regulatory forum. It is certainly true that the present treatment has brought the Trimble County plant before the Commission on a regular basis as rate cases have been filed to obtain a current return on the construction work completed since the test year in the last rate case. Consequently, the Commission is of the opinion that at this time it is in the best interests of both LG&E and its ratepayers to continue the present regulatory treatment of allowing a cash return on Trimble County CWIP.

More fundamental than the issue of allowing CWIP or accruing AFUDC is whether Trimble County should be built at all. If the Commission were to continue to allow LG&E to indefinitely receive a cash return on CWIP for Trimble County, then the Commission would be guilty of "a foolish consistency," a sin that LG&E admonishes against in its brief.[51] The Commission believes that the management of LG&E is responsible for deciding the fate of Trimble County and the record in this case clearly reflects that LG&E would prefer to perform additional studies before deciding

the proper course to follow.[52] The Commission is extremely interested in reviewing these studies so as to determine whether the best option is being pursued.

The Commission intends to move forward with Case No. 8666, Statewide Planning for the Efficient Provisions of Electric Generation and Transmission Facilities, to review not only the need for Trimble County, but also the future generation needs and construction plans of other electric utilities regulated by this Commission. Case No. 8666 will provide the opportunity for LG&E and other interested parties to present evidence of the need, or lack thereof, for Trimble County. The options to be considered will include, but not necessarily be limited to, further deferrals of Trimble County, cancellation of Trimble County, the installation of alternative types of generating units, purchasing capacity, refurbishing older generating units, joint ownership of generation capacity, power pooling, and other options. The Commission will consider these same options when reviewing the generation requirements and construction plans of all electric utilities.

The Commission is aware that these options are not business-as-usual considerations. However, research reports recently filed in Case No. 8666 indicate that the potential savings to be derived from pursuing some of these options on a statewide basis can range into the hundreds of millions of dollars. The Commission notes that utilities in other jurisdictions actively pursue these types of options. LG&E is at a crucial juncture in its planning process. Now is the time to consider whether any lower cost alternatives are available. The Commission

must assure itself and the ratepayers of this state that these options are being actively considered and, where appropriate, aggressively pursued.

Forecasting and Planning

As in the last rate case, a considerable amount of time in this proceeding was devoted to LG&E's load forecasting techniques. After the filing of its case, but prior to the hearing, LG&E revised its peak demand forecasts. According to Mr. Fred Wright, Vice President of Planning and Market Services for LG&E, the "revised peak demand forecast provides for an equivalent compound growth rate over the next decade of 1.6 percent in the high case and 0.7 percent in the low case."[53/] These figures compare to 2.1 percent and 1.2 percent, respectively, in the previous forecast. Mr. Wright expressed his opinion that the forecasts were "as good as any that could have been made, based upon the data that was available."[54/] Mr. Wright did indicate that one of the new tools that LG&E is considering in the future is the development of a data base to support an end-use forecasting methodology.[55/] However, he cautioned that the end-use models can lead to a "fool's paradise, if you rely entirely upon the analytics that come out of these things."[56/]

The Commission supports the move toward end-use modelling by LG&E and would like LG&E to report in its next rate case on its efforts to implement these models and to develop the huge data bases required to run the models. However, the Commission does not agree that a fool's paradise awaits those who trust in end-use

forecasting. Clearly the end-use forecast would be a useful weapon in the planner's arsenal to better understand the uncertainty involved in projecting the future demands of LG&E's customers.

As discussed in the preceding section of the Order, several intervenors' witnesses provided testimony with regard to the continuation of the Commission's treatment of CWIP. Some of the witnesses related their recommendations to LG&E's planning efforts. As a result, LG&E's planning was discussed at great length in this proceeding. As stated above, the Commission's decision to continue allowing a return on CWIP in the rate base was premised on the need to resolve some of the uncertainty surrounding the completion of Trimble County. This uncertainty is highlighted by the differences between LG&E's position in this case--that Trimble County will be needed in 1987--and Mr. Falkenberg's position that Trimble County "would not begin to benefit customers until 20 years after its in-service date."[57/] Given this divergence in positions, it is clear that the Commission is faced with a difficult decision with regard to the continuation of CWIP.

However, as noted in the foregoing section, the record is replete with statements by LG&E's management that additional study is required before deciding how to proceed with Trimble County. Clearly a decision is needed. Even in its minimum construction mode as described by Mr. Royer,[58/] LG&E spent approximately $50 million on Trimble County in 1983. Further, Mr. Wright has

indicated that the minimum level of construction activity cannot be continued much longer if LG&E is to meet the current in-service date of mid-1987.[59/]

The intervenor witnesses argued strongly that the Commission should change its CWIP treatment and prod LG&E's management to make its decision. However, the Commission is painfully aware that a switch to the accrual of AFUDC could lead to grave difficulties later. The Commission has decided that, for this case, its historical treatment of CWIP shall continue. However, the Commission hastens to point out that its decision in this case should not be taken as an indication that this treatment will continue indefinitely in future cases. In fact, the Commission is very much concerned that its decision to continue allowing CWIP in rate base may contribute to the inertia surrounding LG&E's apparent indecision. Accordingly, the Commission wants to establish some procedures to prevent this inertia. Beginning June 1, 1984, the Commission will require LG&E to file monthly reports concerning the activities at the Trimble County construction site. The reports shall contain detailed listings of expenditures to date and for the month, a general description of the level and type of activity, the percentage completion of the plant, and the latest cost estimates to complete the plant. The Commission will carefully scrutinize these reports each month to keep itself apprised of the construction activity and to assure itself that LG&E is pursuing the course of action determined to be appropriate.

Cost of Service

LG&E filed an embedded time-differential cost of service study that used a based-intermediate-peak method to allocate production and transmission demand-related capacity costs to costing periods and then to customer classes. The methodology was generally the same as that which was presented in the last case except that some of the joint distribution costs were classified as either demand or customer related based on a zero-intercept analysis. In previous studies LG&E used a minimum distribution grid analysis for the classification of distribution costs. Mr. James W. Kasey, Coordinator of Rates Research for LG&E, sponsored the embedded cost of service study. Mr. Kasey testified that the zero-intercept method was used because it resulted in only a small shift from demand to customer costs, and it removed the "judgment factor" required in the minimum distribution method.[60/]

The primary challenge to the LG&E cost of service study came from Mr. Nicholas Phillips, Jr., witness for KIUC. The main contention in Mr. Phillip's testimony is that "LG&E's cost of service methodology is inconsistent in the allocation of production plant in that it 'double-counts' the allocation of nontime-differential costs and the allocation of peak-related costs."[61/] However, to properly adjust LG&E's demand allocation factors for the double-counting the minimum demands for each class of customers are needed. When these minimum demands were not available, Mr. Phillips assumed that since LG&E's minimum demand is 55 percent of its average demand, the same relationship held for each

customer class. He than calculated the minimum demand for each class and deducted it from the peak-period demand allocation factors.

Although Mr. Phillips' adjustment to the demand allocators has a theoretical appeal, the Commission is concerned about the validity of his assumption. The Commission believes that LG&E should specifically address the concerns raised by Mr. Phillips in the cost of service study it files in its next rate case. Further, the Commission notes that the class rates of return developed by Mr. Kasey and Mr. Phillips do not differ to a large extent.[62] Therefore, the Commission finds that the cost of service study filed by LG&E should be used as the basis for the allocation of revenues to the customer classes.

Revenue Allocation

Mr. Hart was responsible for spreading the proposed increase in electric revenues among the customer classes. LG&E's objective in developing the proposed increase to each class was to move all the class rates of return to the overall rate of return. Thus, the results from the class cost of service study were analyzed in determining the increase to each class. In order to maintain a gradual movement of the class rates of return to the overall return, Mr. Hart proposed to spread the increase in revenues in such a manner that no rate class is given more than 120 percent nor less than 80 percent of the overall average percentage increase.[63] Accordingly, the maximum increase was set at 13.32 percent and the minimum at 8.88 percent. The exceptions to this

allocation were Street Lighting ("SLE") and Traffic Lighting ("TLE") rates. Since the rates of return from these two classes were above LG&E's overall rate of return, no rate increases were assigned to these two rate schedules.

Mr. Phillips proposed an alternative allocation of revenue. In order to reduce the existing interclass subsidies, Mr. Phillips proposed that the revenue increase be allocated so that no class received an increase "of more than 1.5 times the overall average increase."[64/] As a result, the increases ranged from 5.48 percent for Airco to 16.43 percent for Fort Knox. Similar to LG&E's proposal, SLE and TLE rates were not assigned any increases in rates.

As noted previously in this Order, the Commission finds that the cost of service study filed by LG&E should be the basis for revenue allocation. Further, the Commission is mindful that generally the class rates of return in this case are closer to the overall rate of return in this case than they were in LG&E's last case.[65/] LG&E appears to be meeting its objective of moving class rates of return closer in a gradual manner. Although LG&E's approach may be too gradual for Mr. Phillips, the Commission finds it reasonable. Therefore, the increased revenues should be allocated in similar proportions to those proposed by LG&E.

Rate Design

LG&E designed electric rates based on the criteria of maintaining approximately the present differential between summer and winter rates, increasing the customer charge component by approximately the same percentage as the increase in revenues assigned to

that rate class and assigning a larger percentage increase to the demand charge component than to the energy charge for those rate schedules with both demand and energy.[66/] The last criterion was based on LG&E's embedded cost of service study.[67/] When questioned concerning the methodology utilized in determining the percentage increase to assign to the demand component and the energy component for each class, Mr. Hart stated that he based his methodology on personal judgment of what would be reasonable.[68/]

Mr. Kinloch proposed that the Residential and Water Heating rates of the electric division be consolidated to a uniform residential rate. Mr. Kinloch also proposed a flat energy rate of 6 cents per KWH with an inclining block in the summer of 8 cents per KWH for electric usage above 600 KWH. The arguments given for this proposal were that the electric users of 500 KWH per month were presently subsidizing electric heat and air conditioner customers and that LG&E's present rate structure encourages waste. Calculations were given to substantiate Mr. Kinloch's position.[69/] Due to the lack of rate research evidenced in these calculations the Commission was not convinced to accept Mr. Kinloch's proposals. Therefore, the Commission is of the opinion that the rate design proposed by LG&E for the electric division should be accepted.

LG&E showed that its SLE and TLE rates were earning rates of return considerably above the overall return and therefore proposed no increase in revenue for these two rate schedules.[70/] Louisville proposed that the rates for these two classes be reduced to be more in line with those of the other classes.[71/]

Considering the magnitude of the revenue increase that will be allocated to the other rate classes, the Commission is of the opinion that it would be inappropriate to decrease the charges for LG&E's SLE and TLE rates at this time.

LG&E proposed to allocate the revenue increase to the gas division by increasing the revenues of the various classes from 1.68 percent to 2.73 percent,[72/] with this allocation being based upon judgment by Mr. Hart.[73/] LG&E proposed to increase the customer charge for Rate G-1 to $3 for residential and $6 for non-residential and for Rate G-6 and Rate G-8 to $10. Under the Fort Knox Special Contract there is no customer charge but instead a demand charge of $1.45 per Mcf which LG&E proposes to increase to $1.55. LG&E also proposed that the unit charge per Mcf for all rate schedules be increased by 7.75 cents per Mcf.[74/]

Mr. Hart proposed a larger percentage increase in the customer charge component of the gas rates than in the commodity charge based upon the filed cost of service analysis.[75/] The Commission has accepted LG&E's proposed rate design but has decreased the proposed increase in these rates by the percentage of the reduction in LG&E's proposed revenue increase.

LG&E has proposed additional revisions in three rate classes. One was an increase in the demand credit for interruptible service in its Large Commercial ("LC") and Industrial Power ("LP") rates, another was an increase in the minimum for Supplemental or Standby Service for LC and LP rates, and the third was an increase in the Transportation of Customer-Owned Gas rates. No customers were served under these schedules during the test year;

however, in the event that it becomes necessary to implement these charges the Commission has accepted LG&E's proposal but has decreased the proposed increase in these rates by the percentage of the decrease in LG&E's proposed revenue increase.

In the electric division, LG&E proposed to increase the monthly charge for setting a pole from $1.15 to $1.40. Also a prompt payment provision clause was proposed to be added to the language of Rate G-8 in the gas division. The Commission has determined that these proposals are reasonable and should be approved.

LG&E proposed an increase for both the electric and gas divisions in the charge for disconnect and reconnect service from $10 to $12. The actual cost for a dual trip to disconnect and reconnect a service is in excess of $25.[76/] A proposal from the Residential Intervenors was to lower or remove the reconnect charge after an involuntary termination where nonpayment is due to inability to pay. Under this proposal, the Residential Intervenors claimed, the charges for purely voluntary temporary termination should then reflect the actual costs of these services for everyone.[77/] Although this idea has some appeal, the Commission is not willing to make these changes at this time.

EPRI Participation

In his prepared testimony, Mr. Royer indicated that during the coming year he would be giving serious consideration to the possibility of LG&E becoming a member of the Electric Power Research Institute ("EPRI"). He further stated that should the Commission know of or anticipate any reasons why LG&E's annual

assessment for membership in EPRI would not be recognized for rate-making purposes in the future, LG&E should be told of those reasons now in order to avoid incurring such an expense if there would not be reasonable opportunity for its recovery.

At this time, LG&E has not performed a definitive cost-benefit analysis regarding its potential membership in EPRI.[78/] Absent such an analysis, the Commission is limited as to the response it can give Mr. Royer concerning this matter. However, LG&E is hereby apprised that should it decide to become a member of EPRI it will bear the burden in future cases of justifying the cost of its membership. To do so, LG&E must present clear documentation of the benefits available through membership, its utilization of these benefits and its inability to obtain such benefits at a lower cost. The Commission is also concerned that a substantial portion of EPRI's research concerns nuclear power which is of no direct concern in Kentucky. In future cases, should it decide to join EPRI, LG&E must document whether it could receive all non-nuclear related benefits if it reduced its dues by the portion related to nuclear research. The Commission wishes to emphasize that these are the conditions LG&E <u>must</u> meet <u>should</u> it decide to become a member of EPRI. These conditions in no way represent a prior endorsement of such membership.

Coal Inventory

LG&E proposed to include a coal inventory valued at $25,036,362 in the rate base, for the test year ended August 31, 1983, which consisted of 846,302 tons at a weighted average cost of $29.58 per ton. In LG&E's most recent rate case the Commission

admonished LG&E to manage its coal inventory and in the Commission's Order on Rehearing it was stated that, "...the Commission expects LG&E to develop a formal cost-benefit analysis of its coal inventory level and to incorporate such an analysis in all future rate applications."[79]

LG&E took several measures to comply with the Commission's Orders in Case No. 8616. First, LG&E held its coal purchases to a minimum in order to reduce its coal inventory level. LG&E did not purchase any coal unless it was required under an existing contract, and it renegotiated existing coal supply contracts to obtain reductions in coal shipments. Second, LG&E performed a coal inventory study to determine the optimal coal inventory level entitled, A Study of the Optimal Level of Coal Inventory. Mr. Wright pointed out in his testimony that this coal inventory study, "...establishes the minimum coal inventory which is justified."[80] Third, LG&E adopted a new coal inventory policy based on the results of its coal inventory study. The new policy recognizes the timing of the United Mine Workers ("UMW") labor contract strikes as the major contingency which necessitates the use of a cyclical coal inventory level.

> The new policy provides for a coal inventory level of between 90 and 100 days during the fiscal year leading into a UMW labor contract negotiation and between 80 and 90 days during the fiscal year before the negotiations, and between 70 and 80 days during the fiscal year after the negotiations.[81]

Furthermore, the new policy uses the current 12-month average rate to calculate the days' burn in lieu of the average daily burn rate during the peak summer season used under the old policy.

Using the 12-month average test period burn rate of 9,521 tons per day,[82] the August 31, 1983, coal inventory level equates to 89-days' burn. Since the test year falls in the fiscal year before the UMW labor contract negotiations, LG&E's test-year-end coal inventory is within its new coal inventory policy.

In this proceeding, the Commission has reviewed the test-year-end coal inventory level, evaluated LG&E's new coal inventory policy including the methodology used to arrive at this new policy and determined that no adjustment to the coal inventory level is necessary. The Commission has also accepted LG&E's proposal to price the coal inventory at the test-year-end weighted average inventory cost per ton. The Commission is cognizant of the steps taken by LG&E to reduce its coal inventory level and is pleased that LG&E is striving to manage its coal inventory level. Considering the cost to finance coal inventory, it is imperative that LG&E be sensitive to inventory control. LG&E is beginning to demonstrate the sensitivity which the Commission expects to continue into the future.

Fuel Cost Synchronization

In Case No. 8648, Adjustment of Rates for Wholesale Electric Power to Member Cooperatives of East Kentucky Power Cooperative, Inc., the Commission stated that the fuel cost synchronization issue would be investigated further to determine whether an adjustment "to zero out the fuel adjustment clause" for each electric utility was necessary. The AG's witness, Dr. Gerber, proposed a similar adjustment. Dr. Gerber recommended that the test period (normalized) revenues be reduced by $3.359 million and

it be refunded to the ratepayers via the Fuel Adjustment Clause ("FAC") to correct a problem with the "roll-in" mechanism utilized by the Commission. He also recommended that all fuel expenses and purchased power expenses be removed from this rate case and they be reviewed by the Commission solely in FAC proceedings.

Dr. Gerber calculated the $3.359 million adjustment by taking the difference between FAC revenues actually collected by LG&E as prescribed by the Commission and FAC revenues which would have been collected with a change in the base fuel rate as he recommended. Dr. Gerber did not consider the level of test period FAC expenses [F(m)] in the calculation of his adjustment. Applying Dr. Gerber's adjustment, FAC revenues would be approximately $1.6 million less than FAC expenses for the test period.[83/] If the Commission chose to make such an adjustment, it must consider the level of FAC expenses incurred by LG&E during the test period to properly "zero out the FAC".

Dr. Gerber noted that no adjustment would effectively produce the same results (i.e., refund the $3.359 million over-recovery to the ratepayers) as his recommended adjustment.[84/] If the Commission accepted Dr. Gerber's recommendation in this case, test-period FAC revenues would be decreased, thereby increasing the revenue requirement needed to cover LG&E's test period expenses.

The crux of Dr. Gerber's argument, as he stated during cross-examination, deals with the "roll-in" mechanism utilized by this Commission[85/] and not the fuel cost synchronization issue--a problem which should be addressed in an FAC proceeding and not in

this rate case. The methodology used by the Commission to transfer (roll in) FAC expenses into the base rates was determined in Case No. 8056, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Louisville Gas and Electric Company pursuant to 807 KAR 5:056E, Sections 1(11) and (12), in 1981. Furthermore, Dr. Gerber has not performed an analysis to determine if the over-recovery of FAC expenses by LG&E during the test period was actually due to the roll-in mechanism as he claimed[86/] or whether it was due to varying sales volumes or some combination thereof.[87/]

Certainly, the Commission does not wish to give LG&E, or any other electric utility, the opportunity to recover the same fuel costs twice. Likewise, the Commission does not wish to penalize LG&E or any other electric utility unjustly. Since both alternatives described above produce essentially the same results, the Commission is of the opinion that an adjustment of this type is not necessary at this time.

Interruptible Rates

According to the Order in Case No. 8616, LG&E reported on its efforts to determine the interest in the approved Interruptible Service ("IS") tariff. The IS tariff had been circulated to all eligible customers and several expressed some interest. It appears that LG&E is trying to accommodate those customers.

The Commission is still of the opinion that interruptible rates can be an important ingredient in an overall load management strategy. Therefore, the Commission approves the proposed IS tariff as filed. In addition, LG&E shall in its next rate filing

provide an updated report on its efforts to market interruptible service.

Time-of-Day Rates

Presently, LG&E is in the midst of a rate design experiment to evaluate the cost effectiveness of time-of-day rates. The rates apply to certain large commercial and industrial customers. LG&E has proposed in this case to pass through to the time-of-day customers the rate increases approved for the other large commercial and industrial customers which are served under the LC and the LP tariffs.

The Commission finds that the increases approved for the LC and LP tariff should be passed through to the customers served on the LC Time-of-Day Rate and LP Time-of-Day Rate tariffs in accordance with the methodology as presented in response to Item No. 22 of the Commission's Order dated December 29, 1983. LG&E shall file the revised LC Time-of-Day and LP Time-of-Day tariffs with the workpapers within 20 days from the issuance of this Order.

Marginal Cost of Service

Pursuant to the Order in Administrative Case No. 203, Rate-making Standards Identified in the Public Utility Regulatory Policies Act of 1978, LG&E filed a marginal cost study in this case. Mr. W. Steven Seelye, Mathematician in the Rates and Economic Research Department of LG&E, sponsored the study. The study "used the System Response Method of calculating marginal costs."[88] This method relies on the responses of LG&E's system planners with regard to how the capacity expansion plan would be

changed if demand were increased or decreased. For an increase in demand, the marginal capacity cost was estimated to be $66 per KW per year if purchased power could be used to meet the increase in demand or $92 per KW per year if a combustion turbine was needed. For a decrease in demand, the marginal capacity cost was estimated to be zero. With regards to marginal energy cost a probabalistic production cost simulation model purchased from Ebasco Business Consulting Company ("Ebasco") was used. Marginal transmission capacity costs and marginal distribution costs were also provided.

In Administrative Case No. 203, the Commission ordered that marginal cost studies be filed in rate cases because it believed marginal costs were a valuable input to the rate design issues facing the companies. According to Mr. Seelye, LG&E has not used the study for any rate design matters.[89] Yet in this case, there are several issues to which it seems the results of the marginal cost study could be applied. They could be used in the development of the interruptible tariff, in the review of the shift of costs from energy to demand in the large commercial and industrial tariffs, and in the review of the industrial time-of-day tariffs. In future cases, marginal costs will be needed to develop cogeneration and small power production rates. Thus, the Commission expects to have the issues related to marginal costs before it for some time to come.

However, before these issues return to this Commission there are several other issues that need to be addressed. First, there is the question of why the marginal cost of Trimble County was not used in the determination of marginal capacity cost in the

case of a change in demand.[90] A careful reading of the transcript makes it apparent that there was not a clear resolution of this concern. Second, it was pointed out to Mr. Seelye that there were inconsistencies in the marginal energy cost calculated in the production costing model and the actual energy costs reported by LG&E.[91] Mr. Seelye responded that the problem was the model.[92] Mr. Falkenberg, who previously was employed by Ebasco and helped to develop the model used by LG&E, indicated that the discrepancy may result from LG&E's understanding and use of the model.[93]

The Commission does not require that a marginal cost study be filed in the next rate case except to the extent it may be necessary for the development of cogeneration rates which may have to be filed. However, the Commission does request that the issues raised previously in this section be given additional consideration in future filings of marginal cost studies.

SUMMARY

The Commission, having considered 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 $669,958,991.

2. The rates of return granted herein are 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.

IT IS THEREFORE ORDERED that the rates in Appendix A be and they hereby are approved for service rendered by LG&E on and after May 14, 1984.

IT IS FURTHER ORDERED that the rates proposed by LG&E be and they hereby are denied.

IT IS FURTHER ORDERED that within 20 days from the date of this Order LG&E shall file with the Commission the LC Time-of-Day and LP Time-of-Day tariff sheets and the supporting workpapers for those tariffs.

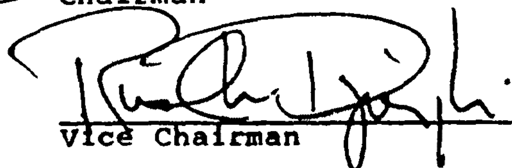
IT IS FURTHER ORDERED that as of June 1, 1984, LG&E shall file monthly reports of the activities and expenditures associated with the construction of Trimble County.

IT IS FURTHER ORDERED that 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.

Done at Frankfort, Kentucky, this 16th day of May, 1984.

PUBLIC SERVICE COMMISSION

Chairman


Vice Chairman

Commissioner

ATTEST:

Secretary

FOOTNOTES TO AN ORDER OF THE PUBLIC
SERVICE COMMISSION IN CASE NO. 8924

1. Wilkerson Supplemental Testimony, pp. 3-4.

2. Ibid., p. 4.

3. Weaver Prepared Testimony, p. 24.

4. Response to Oral Request to Mr. Wilkerson during hearing of March 21, 1984, filed April 2, 1984.

5. Wilkerson Exhibit 4.

6. Hart Exhibit 8.

7. Gerber Exhibit MSG, Statement 7A.

8. Transcript of Evidence ("T.E."), Volume II, March 21, 1984, pp. 201-202.

9. Royer Prepared Testimony, p. 8.

10. Baron Prepared Testimony, p. 12.

11. Wilkerson Prepared Testimony, p. 15.

12. Baron Prepared Testimony, p. 14.

13. Ibid., pp. 14-15.

14. AG's Brief, p. 16.

15. Ibid.

16. Royer Prepared Testimony, p. 17.

17. Wilkerson Supplemental Testimony, p. 1.

18. Royer Supplemental Testimony, p. 5.

19. T.E., Volume I, March 20, 1984, p. 133.

20. Response to Commission Order dated January 25, 1984, Item No. 1.

21. T.E., Volume III, March 22, 1984, p. 177.

22. Ibid.

23. Response to Commission Order dated November 18, 1983, Item No. 52, p. 1.

24. $184,423,161 less $184,065,974.

25. T.E., Volume III, March 22, 1984, p. 176.

26. Ibid., p. 177.

27. Wilkerson Prepared Testimony, pp. 20-21.

28. Order in Case No. 8734, Kentucky Power Company, entered October 31, 1983, p. 4.

29. Response to Commission Order dated November 18, 1983, Item No. 3, p. 2.

30. Response to Oral Request to Mr. Wilkerson during hearing of March 21, 1984, filed April 2, 1984.

31. Weaver Prepared Testimony, p. 24.

32. Monteau Prepared Testimony, p. 8.

33. Ibid., p. 28.

34. Ibid., p. 22.

35. T.E., Volume IV, March 23, 1984, p. 42.

36. Ibid., pp. 42-44.

37. Ronald Prepared Testimony, p. 15.

38. Ibid., p. 9.

39. T.E., Volume II, March 21, 1984, p. 101.

40. Weaver Prepared Testimony, p. 17.

41. T.E., Volume IV, March 23, 1984, p. 298.

42. Kinloch Prepared Testimony, p. 3.

43. Ronald Exhibit 1.

44. Moody's Investors Service, News Reports, April 10, 1984, p. 1901.

45. T.E., Volume V, March 27, 1984, p. 56.

46. Weaver Exhibit CGW, Statement 21.

47. Louisville Brief, p. 6.

48. Falkenburg Exhibit 15.

49. T.E., Volume III, March 22, 1984, p. 135.

50. The Commission also recognizes that some jurisdictions have required shareholders to absorb all costs associated with a cancelled generating plant.

51. LG&E Brief, p. 41.

52. The Commission notes that LG&E's brief states that Trimble County will be finished (LG&E Brief, p. 17). The Commission hopes that this does not include parenthetically whether needed or not, or whether in LG&E's or its consumers' best interest or not. Hopefully, this was merely legal rhetoric and does not represent a completely closed mind on behalf of management.

53. T.E., Volume I, March 20, 1984, p. 140.

54. Ibid., p. 160.

55. Ibid., p. 161.

56. Ibid., p. 205.

57. Falkenberg Prepared Testimony, p. 16.

58. Royer Prepared Testimony, p. 18.

59. T.E., Volume II, March 21, 1984, p. 30.

60. T.E., Volume III, March 22, 1984, p. 200.

61. Phillips Prepared Testimony, p. 9.

62. T.E., Volume III, March 22, 1984, pp. 10-20.

63. Hart Prepared Testimony, p. 4.

64. Phillips Prepared Testimony, p. 17.

65. T.E., Volume III, March 22, 1984, p. 169.

66. Hart Prepared Testimony, p. 5.

67. Response to Commission Order dated December 29, 1983, Item No. 2, p. 1.

68. T.E., March 22, 1984, p. 168.

69. Kinloch Prepared Testimony, p. 4.

70. Hart Prepared Testimony, p. 4.

71. Louisville's Brief, p. 7.

72. Hart Prepared Testimony, p. 6.

73. T.E., March 22, 1984, p. 170.

74. Hart Prepared Testimony, p. 7.

75. *Ibid*.

76. *Ibid*., p. 8.

77. Residential Intervenors' Brief, p. 10.

78. Response to Commission Order dated December 29, 1983, Item No. 26(b).

79. Case No. 8616, Order entered July 5, 1983, p. 3.

80. T.E., Volume I, March 20, 1984, p. 146.

81. *Ibid*., p. 144.

82. Response to Commission Order dated December 29, 1983, Item No. 46.

83. $111,034,493 - 112,679,280 = <$1,644,787>.

84. T.E., Volume IV, March 23, 1984, pp. 197-199.

85. *Ibid*., pp. 199-200.

86. *Ibid*., pp. 193, 199-200.

87. *Ibid*., p. 251.

88. Seelye Prepared Testimony, p. 4.

89. T.E., Volume III, March 22, 1984, p. 251.

90. *Ibid*., pp. 232-254.

91. *Ibid*., pp. 254-256.

92. *Ibid*., pp. 256-257.

93. T.E., Volume IV, March 23, 1984, p. 179.

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 8924 DATED May 16, 1984.

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 SERVICE*

(RATE R)

Rate:

Customer Charge: $3.16 per meter per month.

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

First 600 kilowatt-hours per month	6.130 ¢ per Kwh
Additional kilowatt-hours per month	4.824 ¢ per Kwh

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

All kilowatt-hours per month	6.698 ¢ per Kwh

WATER HEATING RATE*
(RATE WH)

Rate: 4.902 ¢ per kilowatt-hour.

Minimum Bill: $1.95 per month per heater.

*The monthly kilowatt-hour usage shall be subject to plus or minus an adjustment per Kwh determined in accordance with the Fuel Adjustment Clause.

GENERAL SERVICE RATE*
(RATE GS)

Rate:

Customer Charge:

$3.73 per meter per month for single-phase service
$7.45 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 6.539 ¢ per Kwh

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

All kilowatt-hours per month 7.317 ¢ 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 96¢ per month per kilowatt of connected load.

SPECIAL RATE FOR NON-RESIDENTIAL ELECTRIC SPACE HEATING SERVICE - RATE GS*

Rate:

For all consumption recorded on the separate meter during the heating season the rate shall be 4.868 ¢ per kilowatt-hour. This special rate shall be subject to the Primary Service Discount, Fuel Clause and Prompt Payment Provision as are embodied in Rate GS. During the four non-heating season months any electric usage recorded on the separate space heating meter shall be combined with metered usage for other purposes at the same location and be billed at Rate GS.

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*The monthly kilowatt-hour usage shall be subject to plus or minus an adjustment per Kwh determined in accordance with the Fuel Adjustment Clause.

Minimum Bill:

$6.70 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.

DIRECT CURRENT POWER*
(RATE DC)

Rate:

Customer Charge: $8.00 per meter per month.

All kilowatt-hours per month 7.683¢ per Kwh

Minimum Bill:

$2.90 per month per horsepower of customer's total connected direct current load but in no case less than the customer charge. Horsepower of apparatus will be based on manufacturer's rating.

OUTDOOR LIGHTING SERVICE
(RATE OL)
OVERHEAD

Rates:

Overhead Service Mercury Vapor	Rate Per Light Per Month
100 watt*	$ 6.46
175 watt	7.47
250 watt	8.65
400 watt	10.89
400 watt floodlight	10.89
1000 watt	20.89
1000 watt floodlight	20.89
High Pressure Sodium Vapor	
250 watt	11.97
400 watt	14.19
400 watt floodlight	14.19

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

*The monthly kilowatt-hour usage shall be subject to plus or minus an adjustment per Kwh determined in accordance with the Fuel Adjustment Clause.

Underground Service
Mercury Vapor

100 Watt - Top Mounted	$11.48
175 Watt - Top Mounted	12.16

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

Special Terms and Conditions:

1. 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 $1.34 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 PSL)

Rate:

Type of Unit	Support	Rate Per Light Per Year
Overhead Service		
100 Watt Mercury Vapor (open bottom fixture)[1]	Wood Pole	$69.11
175 Watt Mercury Vapor	Wood Pole	84.28
250 Watt Mercury Vapor	Wood Pole	98.46
400 Watt Mercury Vapor	Wood Pole	120.46
400 Watt Mercury Vapor[2]	Metal Pole	201.68

1 Restricted to those units in service on 5/31/79.
2 Restricted to those units in service on 1/19/77.

Overhead Service (cont.)

400 Watt Mercury Vapor Floodlight	Wood Pole	$120.46
1000 Watt Mercury Vapor	Wood Pole	245.24
1000 Watt Mercury Vapor Fooodlight	Wood Pole	245.24
250 Watt High Pressure Sodium	Wood Pole	132.81
400 Watt High Pressure Sodium	Wood Pole	154.59
400 Watt High Pressure Sodium Floodlight	Wood Pole	154.59

Underground Service

100 Watt Mercury Vapor Top Mounted		135.83
175 Watt Mercury Vapor Top Mounted		143.82
175 Watt Mercury Vapor	Metal Pole	163.49
250 Watt Mercury Vapor	Metal Pole	178.01
400 Watt Mercury Vapor	Metal Pole	201.68
400 Watt Mercury Vapor	Alum. Pole	240.76
400 Watt Mercury Vapor on State of Ky. Alum. Pole		139.77
250 Watt High Pressure Sodium Vapor	Metal Pole	225.34
250 Watt High Pressure Sodium Vapor	Alum. Pole	249.85
250 Watt High Pressure Sodium Vapor on State of Ky. Alum. Pole		148.86
400 Watt High Pressure Sodium Vapor	Metal Pole	261.25
400 Watt High Pressure Sodium Vapor	Alum. Pole	285.77
1500 Lumen Incandescent[3] 8-1/2"	Metal Pole	93.70
6000 Lumen Incandescent[4]	Metal Pole	130.91

LARGE COMMERCIAL RATE*
(RATE LC)

Rate:

Customer Charge: $15.63 per delivery point per month.

*The monthly kilowatt-hour usage shall be subject to plus or minus an adjustment per Kwh determined in accordance with the Fuel Adjustment Clause.

3 Restricted to those units in service on 3/1/67.
4 Restricted to those units in service on 3/1/67.

Demand Charge:

	Secondary Distribution	Primary Distribution
Winter Rate: Applicable during 8 monthly billing periods of October through May		
All kilowatts of billing demand	$7.15 per Kw per month	$5.55 per Kw per month

	Secondary Distribution	Primary Distribution
Summer Rate: Applicable during 4 monthly billing periods of June through September		
All kilowatts of billing demand	$10.18 per Kw per month	$8.32 per Kw per month

Energy Charge: All kilowatt-hours per month 3.426¢ per Kwh

INDUSTRIAL POWER RATE*
(RATE LP)

Rate:

Customer Charge: $39.22 per delivery point per month.

Demand Charge:	Secondary Distribution	Primary Distribution	Transmission Line
All kilowatts of billing demand	$8.90 per Kw per month	$6.96 per Kw per month	$5.81 per Kw per month

Energy Charge: All kilowatt-hours per month 3.007¢ per Kwh

*The monthly kilowatt-hour usage shall be subject to plus or minus an adjustment per Kwh determined in accordance with the Fuel Adjustment Clause.

Interruptible Service

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

Supplemental or Standby Service

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 $5.46 per kilowatt applied to the Contract Demand.

SPECIAL CONTRACT FOR ELECTRIC SERVICE TO AIRCO ALLOYS AND CARBIDE (AIR REDUCTION COMPANY, INC.)*

Demand Charge:

Primary Power (28,500 KW)	$11.36 per Kw per month
Secondary Power (Excess KW)	5.69 per Kw per month

Energy Charge:

Primary & Secondary power	2.194¢ per Kwh

SPECIAL CONTRACT FOR ELECTRIC SERVICE TO E. I. DUPONT DENEMOURS & COMPANY

Demand Charge:

All KW of billing demand	$10.92 per Kw per month

Energy Charge:

All KWH	2.316¢ per Kwh

*The monthly kilowatt-hour usage shall be subject to plus or minus an adjustment per Kwh determined in accordance with the Fuel Adjustment Clause.

SPECIAL CONTRACT FOR ELECTRIC SERVICE TO LOUISVILLE WATER COMPANY*

Demand Charge:

KW of billing demand	$7.47 per Kw per month

Energy Charge:

All KWH per month	2.449¢ per Kwh

SPECIAL CONTRACT FOR FORT KNOX*

Demand Charge:

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

All kilowatts of billing demand	$6.00 per Kw per month

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

All kilowatts of billing demand	$8.10 per Kw per month

Energy Charge: All kilowatt-hours per month 2.932¢ per Kwh

RULES AND REGULATIONS GOVERNING THE SUPPLY OF ELECTRIC SERVICE

General Rules

23. Charge for Disconnecting and Reconnecting Service. A charge of $12.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of 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 $12.00.

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 $12.00 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 $12.00.

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*The monthly kilowatt-hour usage shall be subject to plus or minus an adjustment per Kwh determined in accordance with the Fuel Adjustment Clause.

GAS SERVICE

G-1

General Gas Rate

Rate:

Customer Charge:
$2.91 per delivery point per month for residential service
$5.82 per delivery point per month for non-residential service

46.12¢ per 100 cubic feet

Summer Air conditioning Service Under Gas Rate G-1

Rate:

For "Summer Air Conditioning Consumption" determined in the manner hereinafter prescribed, the rate shall be 45.084 cents per 100 cubic feet, subject to the "Purchased Gas Adjustment" and the "Prompt Payment Provision" incorporated in Rate G-1. All monthly consumption other than "Summer Air Conditioning Consumption" shall be billed at the regular charges set forth in Rate G-1.

G-6

Seasonal Off-Peak Gas Rate

Rate:

Customer Charge: $9.65 per delivery point per month

45.079¢ per 100 cubic feet

G-7

Rate for Uncommitted Gas Service

Rate:

45.079¢ per 100 cubic feet

G-8

Dual-Fuel Off-Peak Gas Space Heating Rate

Rate:

Customer Charge: $9.65 per delivery point per month

46.038¢ per 100 cubic feet

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.

Summer Air Conditioning Service Under Gas Rate G-8

Rate:

For consumption recorded during the aforesaid five billing periods the rate shall be 45.084 cents per 100 cubic feet, subject to the "Purchased Gas Adjustment" and to the "Prompt Payment Provision" incorporated in Rate G-8.

T-1

Transportation of Customer-owned Gas

Charges:

The charge for service under this rate schedule shall be sixteen cents (16¢) for each Mcf of gas transported. This charge may be increased or reduced by appropriate filings made in accordance with law and the rates of the Public Service Commission of Kentucky. In addition to such charge, if Company is required to add or modify any facilities in order to initiate or perform the services supplied hereunder, the full cost of such additions or modifications shall be paid for by the Customer.

SPECIAL CONTRACT FOR FORT KNOX

Rate:

Demand Charge: $1.53 per month per Mcf of billing demand

Commodity Charge: $4.4217 net per Mcf delivered

RULES AND REGULATIONS GOVERNING THE SUPPLY OF GAS SERVICE

General Rules

23. Charges for Disconnecting and Reconnecting Service. A charge of $12.00 will be 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 $12.00.

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 $12.00 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 $12.00.