COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT IN ELECTRIC AND GAS RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	))))	CASE NO. 8616

O R D E R

On September 10, 1982, 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 October 1, 1982. The proposed rates would increase annual electric revenues by $64.6 million, an increase of 18.4 percent, and annual gas revenues by $10.3 million, an increase of 5.1 percent. These increases represent an annual increase in total operating revenues of $74.9 million, or 13.6 percent, based on normalized test year sales. On December 20, 1982, LG&E amended its application to reduce its request by $4.4 million to $70.5 million.

On September 13, 1982, the Commission suspended the proposed rate increase until March 1, 1983, in order to conduct public hearings and investigations into the reasonableness of the proposed rates. A hearing was scheduled for January 3, 1983, 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 December 1, 1982, in the Aldermanic Chambers in the Old Courthouse at 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 Carbide, a division of Airco, Inc., ("Airco"), E. I. duPont deNemours and Company ("duPont"), the Department of Defense of the United States ("Defense") and the Office of Kentucky Legal Services Programs on behalf of several residential customers ("Residential Intervenors") of LG&E. 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 January 3 through 6, 1983, with all parties of record represented. Briefs were filed by January 31, 1983, 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 $46,365,766.

COMMENTARY

LG&E is a privately-owned electric and gas utility which distributes and sells electricity to approximately 298,500 consumers in Jefferson County, and in portions of Bullitt, Hardin, Henry, Meade, Oldham, Shelby and Trimble counties and distributes and sells natural gas to approximately 233,200 consumers in Jefferson County and 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 June 30, 1982, 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 $1,134,037,060.[1/] Generally, the proposed rate base was determined in accordance with the Commission's decision in LG&E's last rate case. In a deviation from past cases, LG&E proposed to adjust the inventory level for gas stored underground to reflect increases in the cost of gas since the end of the test period. The Commission recognizes that the price of gas has increased since the end of the test year; however, in determining a test year-end rate base it is our objective to establish the value of investment in utility property at a specific point in time. In establishing the net investment rate base, capitalization, and the adjusted level of operating revenues and expenses, the Commission must develop a proper matching of earnings and rate base. This is done by adjusting the historical test year operations for appropriate known and measurable changes occurring during and subsequent to the test year to arrive at a pro forma statement of operations which coincides with the test year-end rate base and capitalization. LG&E did not propose to expand its year-end capitalization although it did adjust the components therein.[2/] Such adjustments are consistent with

the historical practices of this Commission; however, adjustments to increase the rate base to reflect estimated capital requirements subsequent to the test year are not consistent with the concept of a test year-end rate base. The Commission disagrees with the assessment of LG&E witness, Mr. Frank Wilkerson, Controller, that it is not inconsistent to adjust selected items of the rate base for changes occurring after the test year while other components of the rate base remain at year-end levels.[3/] It is the opinion of this Commission that to adjust the inventory of gas stored underground would improperly update the year-end rate base and result in a mismatch of earnings, rate base and capitalization. Therefore, the proposed adjustment has not been accepted and the net investment rate base allowed herein includes the actual price of gas stored underground.

Coal Inventory -- Throughout this proceeding, the Commission has been especially interested in the issue of LG&E's coal inventory, and for obvious reasons. Although discussion of that inventory has to do with hundreds of thousands of tons of coal, and with such arcane matters as number of days burn and whether the bottom portion of a coal pile contains useable material, the Commission has not lost sight of the vital issue: Coal supply is a very costly inventory which must be financed, and which is reflected in customers' rates. Indeed, the Commission notes that at the end of the test period the LG&E balance sheet reflected a coal inventory valued at $40,941,956.

The coal inventory of 1,412,931 tons at the end of the test year equates to a 118 days' supply of coal, based on the average daily burn rate of 12,000 tons per day which LG&E expected during the peak period from June 15 to September 15, 1982. The June 30 coal inventory level was the highest level achieved at any time during the test year.

LG&E's goal is to maintain a normal seasonal range of 90 to 120 days' supply. Its position is that "system-wide inventory policy is based primarily on judgement and experience with full consideration given to physical and economic factors and to the need to provide reliable electric service to its customers."[4/] Further, LG&E provided a list of factors considered in determining its coal inventory policy which included potential labor problems, demand for electricity, adverse weather conditions, coal market conditions, and contractual limitations.

Using the 13-month average test period burn rate of 9,247 tons per day,[5/] the June 30, 1982, inventory level equates to a 153-day supply which is substantially above the upper limit of LG&E's normal seasonal inventory range of 120 days. Further, using the 5-year average burn rate of 9,773 tons per day,[6/] the June 30, 1982, inventory level equates to a 145-day supply.

It is a principle of sound business management that an inventory must be managed, not left to its own device, nor ignored as something that will take care of itself, but

managed. It must be maintained within a range that reflects a sensitivity not only to the dangers of too small an inventory, but also to the unnecessary costs of too large an inventory.

The Commission believes the record in this proceeding fails to show that LG&E does in fact manage its coal inventory--fails to convey the conviction that LG&E is sensitive to the fact that excessive coal inventory imposes an excessive and unnecessary cost on ratepayers.

The Commission finds it questionable that LG&E should contend it needs a coal inventory of 90 to 120 days. Indeed, during the test period conditions were present that should have encouraged LG&E to seek a minimum inventory: Considerable slack demand in the coal industry made additional supply readily available, and high interest rates made it very costly to carry coal inventory.

The Commission wishes to point out that in Case No. 8429, a general rate proceeding of Kentucky Power Company, Kentucky Power sought Commission approval to include in customer rates the cost of financing a 70-day coal inventory. The Commission determined that during the test year actual inventory had averaged 46 days, and approved rates which reflected a 60-day coal inventory.

In the current LG&E proceeding, in arriving at appropriate rates, the Commission is accepting a coal inventory of 970,935 tons, which is an inventory of approximately 105

days at a daily burn rate of 9,247 tons, which was the 13-month average for the test year, or approximately 100 days at a daily burn rate of 9,773 tons, which was the average for the most recent 5 years. Priced at the year-end average of $28.984 per ton, this allowed inventory level reduces the rate base by $12,810,376. The Commission wishes to make it clear that the 105-day inventory is an interim figure, and that in its next general rate case the burden will rest with LG&E to show why customers should be obligated to pay rates which include the cost to finance a coal inventory which exceeds 75 days.

The Commission believes the 75-day inventory is also an interim level. In subsequent proceedings the burden will rest on LG&E to demonstrate why its coal inventory should not be reduced below 75 days.

The Commission wishes to repeat earlier observations. For a major electric utility, the cost to finance coal inventory is considerable. Further, a fundamental goal of management is inventory control. In competitive enterprises, managers ignore inventory control at their peril. The Commission would like to be convinced that the managers of LG&E demonstrate that same level of sensitivity to inventory control.

Utilities come before this Commission with depressing regularity to seek approval for higher rates. A regular feature of their lament is that much is beyond their control.

Certainly, some important considerations--e.g., interest rates--are beyond their control. But this only makes it all the more important that utility management exert the utmost control over those factors which utilities can control. Coal inventory is such a factor, and in this important regard the Commission intends to make every effort to assure that utility management recognize--and act upon--their responsibility and discretion in this important area.

The rate base has been increased by $506,100 to recognize 1 year's amortization of the "surplus" deferred federal income taxes resulting from the reduction in the corporate tax rate from 48 to 46 percent. This is achieved by decreasing the deferred tax reserve account to reflect the amortization adjustment described on pages 19 and 20 herein.

The net investment rate base has been further 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.

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	$ 147,323,796	$1,312,471,445	$1,459,795,241
Add:			
Materials & Supplies	$ 2,161,097	$ 51,621,657	$ 53,782,754
Gas Stored Underground	30,152,910	-0-	30,152,910
Prepayments	117,616	803,730	921,346
Cash Working Capital	2,398,952	23,547,388	25,946,340
Sub-Total	$ 34,830,575	$ 75,972,775	$ 110,803,350
Deduct:			
Reserve for Depreciation	$ 55,070,034	$ 293,495,117	$ 348,565,151
Customer Advances	1,105,541	988,143	2,093,684
Accumulated Deferred Taxes	13,176,984	91,834,116	105,011,100
Investment Tax Credit (3%)	665,505	1,991,965	2,657,470
Sub-Total	$ 70,018,064	$ 388,309,341	$ 458,327,405
Net Original Cost Rate Base	$ 112,136,307	$1,000,134,879	$1,112,271,186

Capital Structure

In his prepared testimony, Mr. Wilkerson proposed adjustments to LG&E's test year-end capital structure to reflect the sale of common stock in September 1982 and the sale of pollution control bonds in October 1982. Mr. Wilkerson made reductions to trust demand notes and other notes payable that offset the increases in common equity and pollution control bonds. Capitalization was not expanded beyond the test year but the percentages of the various capital components were adjusted. The resulting adjusted test year-end capital structure of $1,049,092,828 contained 44.84 percent debt capital, 11.15 percent preferred equity, 36.50 percent common equity and 7.51 percent Job Development Investment Tax Credit ("JDITC").[7/] Dr. Carl Weaver, witness for the AG, recommended an adjusted test year-end capital

structure that also reflected the sale of common equity and pollution control bonds and the retirement of trust demand notes and other notes.[8/] The difference between Dr. Weaver's proposed capital structure and the company's proposed capital structure is that Dr. Weaver did not include JDITC as a separate component of the capital structure.[9/] His recommended capital structure contained 48.3 percent long-term debt, .2 percent short-term debt, 12.0 percent preferred stock and 39.5 percent common equity.[10/]

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

	Amount	Percent
Bonds	$ 500,896,758	48.34
Other Debt	1,549,088	.15
Preferred Stock	124,920,765	12.05
Common Stock	408,915,841	39.46
Total	$1,036,282,452	100.00

In determining the capital structure the Commission has accepted the adjustments proposed by LG&E to reflect the sale of common stock and pollution control bonds and the retirement of notes payable. The JDITC of $78,825,530 has been allocated to each component on the basis of the ratio of each component to total capital structure excluding JDITC. The Commission is of the opinion that this treatment is entirely consistent with the requirement of the Internal Revenue Service ("IRS") that JDITC receive the same overall return allowed on common equity, debt and preferred stock.

In accordance with the determination in the previous section regarding the value of the coal inventory, the Commission has reduced LG&E's capital structure by $12,810,376 to reflect the lower level of inventory. This reduction has been allocated to the capital structure based on the existing ratio of the capital structure components.

Reproduction Cost

LG&E presented the reproduction cost rate base in Wilkerson Exhibit 9. LG&E estimated the value of plant in service, plant held for future use and construction work in progress at the end of the test year. The resulting reproduction cost is $2,226,349,220 which includes electric facilities of $1,898,867,385 and gas facilities of $327,481,835.

REVENUES AND EXPENSES

For the test period LG&E had net operating income of $85,733,209. LG&E proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions. 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

LG&E proposed adjustments to revenue and expenses for both gas and electric operations to normalize for abnormal weather conditions experienced during the test year. In accordance with past policy the Commission has accepted

LG&E's proposed adjustment to reflect abnormal gas sales during the test year. In accepting this adjustment, the Commission finds that a 30-year base period, as proposed by LG&E for determining normal weather conditions, is appropriate. A current 30-year period provides accurate up-to-date information and at the same time is long enough to mitigate any abnormalities in weather conditions, whether they be yearly or cyclical. It is the Commission's conclusion that a 30-year base period should be used in future proceedings when adjusting gas sales to reflect normal temperature conditions, not only for LG&E but for all other gas utilities within the Commission's jurisdiction.

LG&E's proposed adjustment to electric revenue and expense for temperature normalization would reduce operating income by $1,525,635 based on the assumption that electric sales were greater during the test year by approximately 24 million KWH due to abnormal temperatures. LG&E witness, Mr. John Hart, Jr., Vice President for Rates and Economic Research, calculated the adjustment by determining the number of cooling degree days and heating degree days for the test year based on a mean temperature of 65 degrees and then comparing the test year level of degree days with the National Oceanic and Atmospheric Administration's 1980 30-year average cooling and heating degree days for Louisville. To determine the excess KWH sales, Mr. Hart isolated those rate classes considered to have significant air conditioning or space heating components

and determined the base load and temperature-sensitive load per degree day using a system of simultaneous equations. The excess sales were then converted to revenue and expense by applying the average revenue per KWH for each customer class to the excess KWH and the incremental cost per KWH including the fuel cost during the period of degree day excess plus an allocation of variable maintenance expense.

This type of adjustment is intended to provide a normal level of sales on which to base rates. The Commission agrees with the intent of the proposed adjustment but does not accept its application. Based on the cross-examination of LG&E witnesses and the evidence of record, the Commission is of the opinion that LG&E has not adequately supported either its methodology or its results in determining its base load and its temperature-sensitive load. LG&E selected the month of May 1982 to determine its base load because the use of that 1 month would give the best results, or the best correlation between sales and temperature conditions. The Commission questions this selection since May 1982 was significantly cooler than normal; the numer of cooling degree days for that month was 37 percent less than normal for May and the number of heating degree days was 111 percent greater than normal.[11/] Furthermore, during the test year the month of October 1981 had both fewer cooling degree days and fewer heating degree days than May 1982 and was more moderate than usual with both fewer cooling degree days and fewer heating degree days than normal.[12/]

LG&E also did not recognize any effects of conservation in adopting the 65 degree temperature mean for cooling days although company witness, Mr. Fred Wright, Vice President of Planning and Market Services, testified concerning the ways in which customers reduce their air conditioning usage during milder summer months.[13/] The consistent use of the 65 degree mean temperature over several years, as LG&E has done, would give the impression that conservation measures affect only base load sales with no impact on temperature-sensitive sales. The Commission finds nothing in the record that would support such a conclusion.

LG&E maintained that the electric temperature normalization adjustment should stand alone and not be considered with other sales volume adjustments such as customer usage patterns, abnormal industrial sales and normal growth in customer usage. The Commission is of the opinion that, when properly determined and adequately supported, an adjustment to reflect normalized sales may be considered known and measurable. LG&E was advised of the Commission's position on this type of adjustment in its last rate case, Case No. 8284, and was given the opportunity to introduce such evidence in this proceeding.

The proposed electric temperature normalization adjustment has been given careful consideration. The Commission endorses the principle of normalization; however, in this instance LG&E has given recognition to but one variable

that affects electric consumption while either choosing to ignore all other variables or assuming that they remain constant. The Commission is of the opinion that selective normalization such as this contributes little to making the test year more representative of current operating conditions and is inappropriate for use in the rate-making process. Based on this analysis, and for the reasons listed herein, the Commission has not accepted the temperature normalization adjustment proposed by LG&E for its electric operations.

Gas Costs

LG&E did not propose an adjustment to the cost of gas included in revenue requirements.[14/] However, Mr. Hart testified to the gas cost component of the proposed base rates and the potential for profits on the sale of gas from storage.[15/] Mr. Hart referred to the testimony of Mr. Randall Walker, LG&E's Coordinator of Rates and Tariffs, in Case No. 8284 on the subject of profits on the sale of gas from storage. Mr. Walker testified that the cost of gas withdrawn from storage would generally be lower than the overall gas supply cost,[16/] though LG&E's rates already took this circumstance into account as the gas component of the base rates reflected the lower cost of gas withdrawn from storage in the test year of the preceding rate case.[17/] He calculated an $800,000 lag in gas cost recovery for the 12-month period ending September 30, 1981.[18/] An important part of this calculation was the determination of the gas cost

component reflected in the base rates prescribed by the Commission in LG&E's previous rate case, Case No. 7799.

Mr. Hart testified in the present case that the gas cost component of the proposed base rates is $2.7341 per Mcf sendout or $156,703,257. The method used to calculate this gas cost was the same as that used by Mr. Walker in Case No. 8284.[19/] Additionally, the adjusted revenue at present and proposed rates includes $2,858,731 recovered from purchased gas adjustment ("PGA") billings.[20/] The sum of these two amounts, $159,561,988, represents the total gas cost reflected in the adjusted revenue from both proposed base rates and PGA billings. Gas supply expense per books for the test year was $159,796,974. Therefore, the Commission is of the opinion that gas operating expenses should be adjusted downward by $234,986[21/] to reflect the gas cost component of proposed base rates that would allow for the lower cost of gas withdrawn from storage.

Extraordinary Maintenance

During the test year LG&E incurred $1,150,213 in materials costs for the repair of demister shells at its Mill Creek No. 3 generating unit. The outage for this repair resulted in a reduction in the amount of solid waste processed during the test year with a corresponding reduction in the waste processing operation and maintenance expense that would normally be incurred. LG&E proposed an adjustment of $968,139 to reflect a normal level of waste processing

operation and maintenance expense.[22/] This adjustment recognized the Mill Creek No. 3 maintenance outage and the operation of the Mill Creek No. 2 sulphur dioxide removal system ("SDRS") for only the last 7 months of the test year. The adjustment reflects a full year's operation of the waste disposal system without the outage experienced during the test year. However, LG&E proposed no adjustment to exclude, for rate-making purposes, the cost of the demister shell repairs. LG&E witness, Mr. H. A. Wentworth, Jr., Assistant Vice President and General Superintendent for Electric Operations, explained that such an adjustment would have been offset by a $1,032,770 adjustment to reflect a normal level of SDRS operation and maintenance expense.[23/] The Commission is of the opinion that the adjusted test year would be more representative of normal operating conditions with the exclusion of the $1,150,213 expense for the demister shell repairs and the inclusion of the $1,032,770 for SDRS operation and maintenance expense. The net effect of these adjustments is to reduce operating expenses by $117,443.

SDRS O&M

The proposed adjustment referred to in the preceding section for increased waste processing operation and maintenance expense associated with the Mill Creek processing plant has been modified to exclude the 5 percent portion of that expense that represents fixed costs. Based on the testimony of Mr. H. A. Wentworth, the Commission is of the opinion that

a variable component of 95 percent should be applied in the calculation of this adjustment.[24/] This application results in reducing the proposed adjustment by $93,945.

LG&E proposed an adjustment of $1,138,070 to reflect the annual sulfur dioxide removal expenses associated with its Mill Creek No. 4 generating unit, which was placed into service in September 1982. LG&E did not propose any other adjustments specifically related to additional revenues or expenses resulting from the commercialization of Mill Creek No. 4 other than its adjustment to reflect the unit's annual depreciation expense. LG&E indicated that the estimated sulfur dioxide removal expense was based on the assumption that the new unit would replace 80 percent of the production by Cane Run Units 1, 2 and 3.[25/] No adjustments were proposed to reflect any reduction in costs associated with the reduced production by the Cane Run units despite the statement by Mr. Wright that "certainly the maintenance costs per kilowatt hour of generation for the Mill Creek units ... would tend to be less than [for] the old Cane Run units."[26/]

The Commission is of the opinion that an adjustment such as LG&E has proposed is incomplete without some recognition of additional revenues the new unit will generate or decreased expenses from reduced production by the Cane Run units. Adding to our concern is Mr. Wright's statement that "Mill Creek 4 is still in this period of not having all the bugs worked out, and for the first year of service, that

unit will be on and off..."[27/] With the level of production by Mill Creek No. 4 so uncertain the projected level of operating costs is speculative, at best. Furthermore, taking into consideration the aforementioned incompleteness of the proposed adjustment, the Commission finds that it is not appropriate to increase production plant operating costs further for rate-making purposes.

Amortization of Excess Tax Deferrals

Effective January 1, 1979, the corporate federal income tax rate was reduced from 48 to 46 percent. Therefore, income taxes deferred on differences between book and tax depreciation prior to 1979 at a 48 percent tax rate will be paid at a 46 percent tax rate when these differences reverse. An inherent assumption in computing the amount of deferred taxes provided is that the tax rate will remain the same; however, this has not occurred. There is a difference between the amount deferred at the 48 percent rate and the amount to be paid at the 46 percent rate which can be characterized as excess deferred taxes.

At June 30, 1982, LG&E reported excess deferred federal income taxes of $2,530,500.[28/] To better insure that this surplus is credited to the ratepayers who originally paid the taxes at 48 percent, the Commission will amortize this amount over 5 years for rate-making purposes. This results in an annual reduction in income tax expense of $506,100 which has been allocated to gas and electric

operations in proportion to the existing deferred tax reserve. This adjustment does not represent an abrupt change of this Commission's practices, but merely the recognition of the result of the tax rate reduction. A corollary adjustment has been made to reduce accumulated deferred taxes to recognize the first year's amortization, thus increasing the rate base by a like amount. In order that the accumulated excess deferred taxes can be readily identified in future rate proceedings, LG&E should transfer the excess to a separate liability account.

It should be pointed out that if the tax rate is increased in the future, fairness will require that any deficiency in the deferred tax reserve be provided through rates at that time.

Remodeling Costs

During the test year LG&E incurred an expense of $31,296 for the amortization of the cost of remodeling rental property, for which the actual work was performed during 1980. The remodeling cost was amortized over a period of 2 years which ended in April 1982. Inasmuch as this expense is no longer being incurred, the Commission has made an adjustment to reduce operating expenses by $31,296. Mr. Wilkerson noted under cross-examination that LG&E was aware of several possible adjustments of this magnitude but chose not to pursue them due to their relative immateriality.[29/] The Commission cannot overlook an adjustment which is an obvious reduction in cost even though the significance is small.

Wages and Salaries

LG&E proposed an adjustment of $7,125,236 for increased wages and salaries. This adjustment normalized wages and salaries to the test year-end level and also included three out-of-period adjustments which totalled $4,854,049. These adjustments reflected a 10 percent increase to non-union non-exempt employees, a 10 percent increase to union employees, and a 6 percent increase to non-union exempt employees. The Commission is of the opinion that increases of this magnitude are unreasonably high under present economic conditions and LG&E's customers should not be required to bear the full amount of the increases.

Current trends indicate a continued decrease in the rate of inflation with no measurable decline in the record high unemployment rate. These trends have caused recent wage settlements in many of the nation's non-regulated industries to reflect greater concern for job security than with large wage increases. Under present economic conditions, it is imperative that utility employees not be overly compensated compared to their counterparts in competitive industries and it is the Commission's responsibility, as a surrogate for competition, to insure that the utilities under its jurisdiction are not insulated from the effects of today's economy.

The Consumer Price Index ("CPI") is a primary measure of inflation and since September 1982, its annual percentage increase has been 5 percent or less, declining to less than

4 percent annually at the end of 1982. The CPI is frequently used by industry in setting wage increases and the Commission finds it to be useful in analyzing wage and salary adjustments. At the time the 10 percent wage increases became effective for LG&E's non-union non-exempt employees and its union employees the CPI reflected a yearly increase of approximately 5 percent. The Commission is of the opinion that this is the maximum increase that should be passed on to LG&E's consumers for the October and November 1982, wage and salary increases. When other utilities are laying off employees and reducing and/or freezing wages, the Commission finds it unreasonable for LG&E to ignore today's economic realities and expect its consumers to bear double-digit wage increases. The Commission realizes that LG&E's increase to its union employees was set by contract; however, when the need arises contracts can be re-negotiated or the number of employees can be reduced. The record in this case does not show that LG&E has attempted to implement either of these actions.

The third component of LG&E's out-of-period adjustment reflected a projected 6 percent increase for the non-union exempt employees scheduled for February 28, 1982. The effective date is 8 months beyond the end of the test year and the magnitude of the increase is strictly at management's discretion. This employee group received an 11 percent increase as recently as March 1982, and the Commission is of

the opinion that any further increase at this time would be imprudent and that LG&E's customers should not be required to support it through rates.

Based on the above findings, the Commission has reduced LG&E's proposed adjustment by $2,769,674. Moreover, the Commission puts LG&E on notice that if future wage increases are granted which the Commission determines to be excessive, the Commission will take appropriate action to insure that the customers of LG&E will not bear that portion found to be excessive.

Year-end Electric Customers

The adjustment proposed by LG&E to annualize revenues and expenses to reflect year-end electric customers was calculated using normalized sales, which reflected the proposed electric temperature normalization adjustment. Since the temperature normalization adjustment has not been accepted, the year-end customer adjustment has been restated using actual test year sales. Based on actual test year sales, the adjustment to operating income before taxes has been increased from $780,895 to $783,105, an increase of $2,210.

Interest Expense

LG&E proposed an adjustment of $952,376 to short-term interest expense to reflect the carrying costs of its stored gas inventory based on repricing the inventory to reflect increases in the cost of gas since the end of the test year. LG&E has not proposed such adjustments in previous rate cases

although similar increases in the cost of gas have occurred in the past. In proposing this expense adjustment, LG&E did not reflect an increase in total capitalization as a result of the increased cost of gas nor did it show that its inventory of stored gas has historically been supported by short-term borrowings. Therefore, the Commission does not accept LG&E's proposed interest adjustment for the increase in its inventory of stored gas.

Interest Synchronization

LG&E disagrees with the Commission's past treatment of interest expense as it relates to JDITC. LG&E and its witness, Mr. Jay H. Price, Jr., Partner, Arthur Anderson and Company, question the practice of assigning JDITC to all components of the capital structure and treating the interest cost associated with JDITC debt capital as a deduction in computing federal income tax expense allowed in the cost of service.

LG&E contends that the Commission's practice results in a reduction in allowed income tax expense for rate-making purposes below the tax expense actually incurred since the interest associated with JDITC debt capital is not shown on its tax return. LG&E further contends that the Commission treats JDITC in a manner which the IRS could possibly consider to be a violation of the IRS regulations.[30/]

The Commission finds LG&E's arguments to be unpersuasive and is of the opinion that its treatment of JDITC is

consistent with IRS Regulation 1.46-6(3) which requires that JDITC receive the same overall return allowed on common equity, debt and preferred stock equity. The regulation requires that JDITC be treated as though it were provided by preferred shareholders, common shareholders, and creditors. In attempting to apply proper regulatory principles, the Commission cannot be limited by the spectre of a change in law or regulations. Therefore, in accordance with past practice the Commission has applied the embedded cost rates applicable to long-term debt and other debt to the JDITC allocated to the debt components of the capital structure. Using the adjusted capital structure allowed herein, the Commission has computed an interest adjustment of $3,137,114 which results in a reduction to income taxes of $1,544,714.

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 $3,670,266 to $89,403,475.

The adjusted net operating income is as follows:

	Gas	Electric	Total
Operating Revenues	$200,986,089	$336,502,974	$537,489,063
Operating Expenses	193,245,512	258,510,342	451,755,854
Pro Forma Adjustments	250,289	3,419,977	3,670,266
Net Operating Income as Adjusted	$ 7,990,866	$ 81,412,609	$ 89,403,475

RATE OF RETURN

In his original prefiled testimony, Mr. Wilkerson proposed to use an 8.02 percent cost rate for long-term debt, a 10.94 percent cost rate for trust demand notes, a 10.5 percent cost rate for new pollution control bonds and an 8.09 percent cost rate for preferred stock.[31/] The 8.02 and 8.09 percent cost rates represented embedded cost rates for long-term debt and preferred stock. The 10.94 percent cost rate for trust demand notes was equal to the annual simple interest yield equivalent of the discount rate adopted by General Electric Credit Corporation for its 180-day commercial paper[32/] at August 13, 1982.[33/] The 10.5 percent cost rate applied to the new pollution control bonds was an assumed rate because those bonds had not been issued at the time Mr. Wilkerson's testimony was filed.[34/] Mr. Wilkerson filed a revised exhibit in which he reduced the cost rates for trust demand notes to 8.92 percent to reflect the more current rate at December 13, 1982,[35/] and for pollution control bonds to 9.4 percent to reflect the actual interest rate of the bonds issued in October 1982.[36/]

Dr. Weaver proposed an 8 percent cost rate for both long-term debt and preferred stock.[37/] The 8 percent cost of long-term debt included the new pollution control bonds at an assumed 9 percent cost rate.[38/] Dr. Weaver's 12.6 percent cost rate for short-term debt was based on a Value Line forecast of the 1983 prime rate.[39/]

The Commission is of the opinion that an 8.06 percent cost rate for long-term debt is reasonable and should be applied to the long-term debt component of LG&E's capital structure. This cost rate is calculated by including $15,000,000 of pollution control bonds, at a 9.4 percent cost rate, in long-term debt, which has an embedded cost of 8.02 percent. The Commission is also of the opinion that LG&E's proposed 8.92 percent cost rate for short-term debt is reasonable and should be applied to the short-term debt component of its capital structure. Finally, the Commission is of the opinion that an 8.06 percent cost rate for preferred stock is reasonable and should be applied to the preferred stock component of LG&E's capital structure.[40/]

In his prefiled testimony, Mr. Wayne D. Monteau, Senior Vice President, H. Zinder and Associates, witness for LG&E, proposed a return on common equity within the range of 17 to 18 percent.[41/] Mr. Monteau performed a comparable earnings study, a risk premium analysis and a discounted cash flow study for comparable companies. Mr. Monteau concluded from his comparable earnings study that LG&E required a higher rate of return on its common equity than it had achieved or had been allowed in the past.[42/] A composite cost of common equity for the 93 utilities listed on the New York Stock Exchange was developed, using a discounted cash flow methodology proposed by the Federal Power Commission ("FPC").[43/] Mr. Monteau determined that the average spread

between the composite cost of equity and Moody's AA-rated bond yields from 1975 to 1981 was 3.86 percentage points.44/ Adding this spread to LG&E's bond yields produced the range of returns on equity proposed by Mr. Monteau.45/ The supplement to Mr. Monteau's schedule 13 showed a cost of equity of 16.58 percent determined by FPC methodology and a spread between Moody's AA-rated bonds and the cost of equity of 2.63 percentage points.46/ Due to improvements in the money sensitivity analysis, also known as a risk premium analysis. The spread he developed varied from a high of 4.71 percentage points in 1975 to a low of 2.03 percentage points during the 3 months ended August 31, 1982.48/ Mr. Monteau did not perform a discounted cash flow analysis of any kind for LG&E. In response to a data request at the hearing, Mr. Monteau performed a discounted cash flow calculation for LG&E using the FPC methodology. For the 3 months ended October 1982, the indicated cost of equity for LG&E was 15.44 percent and the forecasted cost of equity was 15.39 percent.49/ In his cost of equity analysis, Mr. Monteau made no allowance for the inclusion of 100 percent construction work in progress ("CWIP") in LG&E's rate base without an allowance for funds used during construction ("AFUDC") offset. Dr. Weaver stated that this treatment of CWIP made LG&E relatively less risky than a firm that did not include CWIP in the rate base or had an AFUDC offset.50/ The price of LG&E's common equity has improved since the test year. Since the first quarter of

1980, LG&E bond yields have been lower than Moody's AA-rated bond yield average.[51/] This indicates that investors perceive LG&E bonds to be less risky than the average AA-rated utility bond. The common equity ratio of 39.46 percent, allowed by this Commission in the capital structure section of this Order, is the highest in the historical period since 1972.[52/]

In his prefiled testimony, Dr. Weaver proposed a cost of equity within the range of 14.5 to 15.1 percent.[53/] He performed a discounted cash flow analysis, an earnings-price ratio analysis and a comparable earnings analysis to develop his recommended return on equity.[54/]

The Commission has given due consideration to the improvements in the capital markets and LG&E's equity ratio and stock price. Mr. Monteau's cost of equity analysis had limitations, which were discussed earlier. Therefore, the Commission is of the opinion that a return on common equity in the range of 14.75 to 15.75 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. Considering current economic conditions and LG&E's financing requirements, the Commission finds that a return on common equity of 15.25 percent will best meet the above objectives. This results in an overall

cost of capital of 10.9 percent and provides a rate of return on net investment of 10.15 percent.

REVENUE REQUIREMENTS

The Commission has determined that LG&E needs additional annual operating income of $23,535,263 to produce a rate of return of 15.25 percent on common equity based on the adjusted historical test year. After the provision for state and federal income taxes of $22,830,503 there is an overall revenue deficiency of $46,365,766 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 $112,938,738. A breakdown of the required operating income and the increase allowed herein between gas and electric operations is as follows:

	Total	Electric	Gas
Net Operating Income found reasonable	$112,938,738	$101,552,546	$11,386,192
Adjusted Net Operating Income	$ 89,403,475	$ 81,412,609	$ 7,990,866
Net Operating Income deficiency	$ 23,535,263	$ 20,139,937	$ 3,395,326
Additional Revenue required	$ 45,365,766	$ 39,676,786	$ 6,688,980

The additional revenue granted herein will provide a rate of return on the net original cost of 10.15 percent and an overall return on total capitalization of 10.9 percent.

The rates and charges in Appendix A are designed to produce gross operating revenue, based on the adjusted test

year, of $659,257,255 which includes other operating revenue of $5,733,821. This level of operating revenue includes $394,142,795 in electric revenue and $265,114,460 in gas revenue. The gas rates also include $59,600,000 from the additional PGAs approved since LG&E's last general rate increase.

OTHER ISSUES

Rate Design and Billing

LG&E did not propose any changes to its current rate design nor did any intervenor object to the current rate design. The Commission is of the opinion and finds that the rate design proposed by LG&E is fair and equitable and therefore should be approved.

In the Electric Department, LG&E proposed to restrict the size of the load of new customers who wish to be served under Rate GS to connected loads of less than 200 kilowatts instead of the current restriction of connected loads of less than 300 kilowatts. In the Gas Department, LG&E proposed to cancel Rate Schedules G-1A and G-2 and to serve the customers served thereunder on Rate Schedule G-1. The Commission is of the opinion that the customers of LG&E will be better served if these changes are approved and that LG&E should amend its tariffs as proposed.

The Residential Intervenors proposed that customers of LG&E desiring to continue one service when unable to pay for

both gas and electric service should be given the option of doing so by being allowed to pay on either the gas or electric portion of their bills. The proposal deserves further discussion as it has potential merit; however, the Commission is of the opinion that this issue would be better addressed in a complaint proceeding brought by affected customers.

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 an embedded cost of service study in this case using a model developed by Ebasco Business Consulting Company. The distinguishing feature of the model was its allocation of LG&E's test year production and transmission demand-related capacity costs to costing periods and then to customer classes. The study designated 29 percent of the capacity costs as non-time differentiated and allocated these costs to the customer classes based on average demand or energy usage.[55/] Another 31 percent was designated as winter peak capacity costs and allocated to the customer classes based on class contribution to winter peak.[56/] The remainder was assigned as summer peak capacity and was allocated based on the class contribution to system coincident peak.[57/]

Airco presented an alternative cost of service study. Airco's study allocated the production and transmission

capacity costs to customer classes based on contribution to system coincident peak.

Of the two cost of service studies filed in this proceeding, LG&E's study is preferred. LG&E's decisions to install baseload units were certainly influenced by factors other than the magnitude of the sytem peak load. LG&E witness Mr. James W. Kasey, Coordinator of Rate Research for LG&E, testified that capacity was "installed to meet durational-type loads."[58/] LG&E's embedded production and transmission costs were clearly caused by factors in addition to system peak demand. Thus, these costs should be allocated to the customer classes based on the factors that caused the investments in capacity. The LG&E study accomplishes this by allocating some of the production and transmission costs to the customer classes on the basis of average demand or energy.

Airco's brief includes a hypothetical example that purports to illustrate that LG&E's cost allocation methodology is flawed. The example assumes two customers, A and B, who use the same amounts of energy. A has a 10 MW demand at winter peak and zero MW demand at summer peak, while B has a zero MW demand at winter peak and a 10 MW demand at summer peak.[59/] The example demonstrates that A would be allocated more of the production and transmission costs than B. Given the size of LG&E's summer peak relative to its winter peak, this result appears perverse. However, using the same hypothetical example, if a single coincident peak allocation

methodology, which Airco supports, is applied, customer A would not be allocated any capacity costs. This example clearly demonstrates why the Commission finds the coincident peak allocation method undesirable.

The Commission finds the cost of service study filed by LG&E preferable to the study filed by Airco. The LG&E study should be used as the basis for the allocation of revenues to the customer classes.

Revenue Allocation

LG&E has historically allocated proposed revenue increases to customer classes uniformly. In this case LG&E has recognized the results of its cost of service study and proposed non-uniform increases. The study calculated the overall rate of return to be 7.66 percent, residential 5.95 percent, general service 11.63 percent, large commercial 8.42 percent, industrial 8.52 percent, special contracts 6.63 percent, and street lighting 8.88 percent. LG&E witness Mr. Hart states that LG&E has "given those rate classes or rates schedules with rates of return in excess of 2 percentage points of the overall rate of return a smaller increase or no increase. All other classes were given approximately the same percentage increase."[60/] LG&E proposed a gradual change in the revenue allocation in an effort to not be "overly disruptive."[61/] It would increase revenues by approximately 19.8 percent for all classes except general service and street lighting; their increases would be 12.26 percent and 14.28 percent, respectively.[62/]

Airco witness, Mr. Maurice Brubaker, developed an alternative allocation of LG&E's proposed increase. His alternative was based on the results of his cost of service study which used the coincident peak demand allocation method. Also, he developed his proposed increases by examining the increases in the nonfuel revenues, and considering inter-class revenue subsidies and the rate-making objectives of gradualism and revenue stability. His recommended increases are 29.3 percent for residential, 8.8 percent for general service, 16 percent for large commercial, 12 percent for industrial, 15.6 percent for special contracts, and 9.7 percent for street lighting.[63/]

Since the Commission does not find the coincident peak demand allocation method used by Airco appropriate in this case, it concludes that the proposed revenue allocation of Airco is also inappropriate. The Commission finds the gradual approach for reallocating class revenues as proposed by LG&E to be reasonable. Its approach recognizes the rate-making objectives of revenue stability, rate continuity and understandability, as well as relative risk differentials between classes.[64/] Therefore, the increased revenues should be allocated in similar proportions to those proposed by LG&E.

Interruptible Rate

Pursuant to the Order in Administrative Case No. 203, LG&E has filed an interruptible rate schedule in this case. The rate schedule makes interruptible service available to

Large Commercial and Large Industrial Power customers with demands of at least 1,000 kilowatts.

LG&E witness, Mr. Wright, identified interruptible rates as one of the justifications for the lower load forecasts of LG&E.[65/] Yet LG&E has not performed any market studies with regard to the acceptability of the rate.[66/] He did not believe that many customers would be interested.[67/] LG&E witness, Mr. Hart, did not know how many customers were eligible for the interruptible service rate.[68/] Obviously more work needs to be done to determine if an interruptible tariff will have any impact on the future growth in LG&E's load.

The Commission is of the opinion that an interruptible rate is a reasonable means to attempt to control load growth. The Commission intends to encourage such rates. Therefore, the Commission has approved the proposed interruptible service tariff with the understanding that LG&E will use the tariff to assess the potential interest of its customers. In its next rate case LG&E shall report on its efforts to determine the interest in the tariff and consider proposing modifications that are cost-justified and which may promote a wider use of the tariff.

Load Forecasting and Planning

Considerable time and effort in this proceeding were devoted to examining the load forecasting and planning activities of LG&E. However, when one considers the

consequences that result from these activities, the time and effort expended in this proceeding should come as no surprise. Higher interest rates and construction costs have substantially increased the cost to expand capacity. To compound matters, the recent performance of the economy coupled with escalating energy prices, which result in more conservation, have greatly increased the uncertainty associated with the load forecasts. The higher cost to build and the increased uncertainty mean that the cost to err as well as the probability of an error have both increased. The Commission, the utilities, and other interested parties must increase their understanding of the forecasting and planning activities, which are inextricably linked and strive to improve the utilities' performances in these areas.

LG&E has made two recent changes in its forecasting and planning which demonstrate that it wishes to improve its performance. First, in its forecasting efforts LG&E now develops a range of forecasted growth. LG&E witness, Mr. Wright, describes its published load growth forecast as the median of two separate forecasts: a low forecast which uses pessimistic assumptions and a high forecast which uses optimistic assumptions.[69/] This method gives explicit recognition to the uncertainty associated with LG&E's forecasting activities. Second, LG&E has adopted a flexible scheduling approach with regard to the remaining expenditures associated with Trimble County Unit No. 1.[70/] According to

LG&E witness, Mr. Robert L. Royer, President and Chief Executive Officer, the construction at Trimble County Unit No. 1 is currently at a point at which current expenditures can be deferred and LG&E can reassess on at least "an annual basis the need for that unit within the next 3-year period."[71] This increased flexibility means that "the bulk of the remaining expenditures required for commercial operation of the unit can be deferred until the last 2 years of construction effort prior to service, at which time a high level of confidence is likely to be able to be applied to a determination that the unit will need to be put in service."[72] Assuming the costs associated with deferral do not exceed the benefits, the enhanced flexibility is a desirable feature to incorporate into the planning process.

Although LG&E has taken some steps to change its load forecasting and planning activities, there is considerable room for improvement. LG&E should quantify programs that will affect its future load growth. LG&E witness, Mr. Wright, enumerated seven studies and projects that he believed justified the lower load forecasts LG&E has adopted.[73] On cross-examination, Mr. Wright could not quantify the impact of the seven programs but he had concluded that they would have some impact so he "considered them in somewhat of a qualitative fashion."[74] Similarly, when Mr. Wright was asked whether LG&E was considering utilizing more sophisticated load forecasting techniques, he responded that he was

"not convinced that these sophisticated techniques are any better" than what LG&E currently uses.[75] Although some would argue that more quantification and sophisticated techniques may not increase the accuracy of load forecasts in the short run, most would agree that the quality of the forecasts would be improved. With more sophisticated forecasting methods there would be a better understanding of the factors that led to a forecast not being realized. Also, use of many of the more recent load forecasting techniques would facilitate the consideration of alternative scenarios that would result from making various assumptions concerning factors such as price changes, appliance saturations, and economic variables. The Commission understands that increased efforts to quantify specific portions of LG&E's demand and to implement more sophisticated techniques are not undertaken without some costs. However, the better quality of forecasts and the enhanced planning that would result would likely offset these costs. Thus the Commission encourages LG&E to investigate the need for more quantification in its forecasts and to implement more sophisticated load forecasting techniques.

The Commission is also concerned that LG&E has not quantified the benefits or cost savings that result from its decisions to defer capacity, in particular Trimble County Unit No. 1. LG&E witness, Mr. Wright, stated that the deferral of the Trimble County unit from a 1986 to a 1987

commercial operation date increased the capital costs by $53 million.[76] However, when asked for an estimate of the associated benefits or cost savings that result from the deferral, Mr. Wright responded that he "can't put a number on it."[77] The increased capital costs of $53 million are very substantial to offset. The Commission expects to see evidence in the future of the benefits and costs associated with changes in construction and retirement plans.

Further, the Commission was distressed to learn that LG&E's planning is done in almost complete isolation from the planning of neighboring utilities. LG&E witness, Mr. Wright, stated that representatives of East Kentucky Power Cooperative, Inc., had contacted him prior to LG&E's decision to defer the Trimble County unit and prior to East Kentucky Power's decision to defer its J. K. Smith plant. According to Mr. Wright, the representatives from East Kentucky Power were "very interested" in LG&E's plans concerning the Trimble County unit since "they were placing some reliance on the possibility of purchasing capacity" from LG&E.[78] Mr. Wright had nothing to tell the East Kentucky Power representatives at that point because LG&E had not made its decision. However, after LG&E decided to defer Trimble County Unit No. 1, there still were no discussions with East Kentucky Power.[79]

Louisville witness, Mr. Sam Rhodes, testified with regard to LG&E's load forecasting methods and capacity planning. He identified several inconsistencies between

LG&E's forecasts and its historical growth rates for certain portions of its demand.[80/] He expressed concern over the lack of quantification utilized by LG&E to determine the impact of various load management programs. By using various assumptions, Mr. Rhodes was able to present a sensitivity analysis with respect to LG&E's capacity plans. The findings of the analysis led Mr. Rhodes to recommend that the Commission order an independent and comprehensive review of LG&E's forecast.[81/]

The Commission is concerned about LG&E's load forecasting, and about such related issues as the benefits to be realized by a cost-effective conservation program; the most prudent course to follow concerning the Cane Run units; the financially sound course to pursue with regard to the much-delayed Trimble County Unit No. 1; and the extent to which it would be economically beneficial for LG&E to purchase power from and/or sell power to neighboring utilities. These concerns are the heart of the Commission's belief that it has an obligation to pursue, for Kentuckians, an energy strategy that represents least-cost consistent with appropriate reliability, and the further belief that the least-cost system does not exist.

Responding to those concerns and beliefs, the Commission will order an independent consulting firm, to be selected by the Commission, to undertake a thorough review and make recommendations with regard to the several items of concern set forth above.

Trimble County CWIP

Historically, LG&E has included CWIP in its rate base without accruing AFUDC. Mr. Sam Rhodes recommended that LG&E be required to accrue AFUDC for all construction costs associated with Trimble County Unit No. 1 until the Commission has evaluated LG&E's future capacity requirements. Mr. Rhodes premised his recommendation on the assumption that the service lives of Cane Run Units 1, 2 and 3 could be extended until 1991, thereby deferring the commercialization of Trimble County Unit No. 1 for another 4 years. Based on Mr. Rhodes' analysis, LG&E's revenue requirement for Trimble County Unit No. 1 with the full AFUDC offset would be approximately $5.8 billion over the 30-year life of the plant.[82/] Without AFUDC, the 30-year revenue requirement for the Trimble County plant would be approximately $3.2 billion.[83/] Under Mr. Rhodes' proposal, there would be no revenue requirement for Trimble County Unit No. 1 until the plant is placed in service, but from that point on the annual revenue requirement would be approximately two times as great as would be required without the AFUDC accrual. Mr. Rhodes calculated the net present value of the revenue requirements associated with Trimble County Unit No. 1 at various discount rates ranging from 10 percent to 18 percent both with and without the AFUDC accrual and determined that at present it would be more advantageous for the ratepayers if LG&E were required to accrue AFUDC.

In performing his analysis, Mr. Rhodes made no determination as to how his recommendation would affect LG&E's capital costs, its relative risk as perceived by the financial community, or its financial integrity. Also, Mr. Rhodes did not determine whether it would be possible for the Cane Run units to continue to operate beyond 1987. The Commission is of the opinion that these factors must be considered in determining whether LG&E should be required to accrue AFUDC. Mr. Rhodes did not fully explore the possible impact of his recommendation on LG&E and ultimately, its consumers. While there are arguments in favor of accruing AFUDC, the Commission is of the opinion that they are unpersuasive in this instance. As can be seen from the resultant revenue requirement, Mr. Rhodes' proposal results in a short-term solution to the problem of increasing rates while further contributing to the long-term dilemma that faces LG&E and this Commission. Particularly in view of LG&E's long-time treatment of CWIP, the Commission does not find sufficient cause to require LG&E to accrue AFUDC on the construction of Trimble County Unit No. 1, nor do we find such a change to be proper regulatory treatment in this instance. Therefore, the Commission will not require that LG&E accrue AFUDC for the construction costs associated with Trimble County Unit No. 1 but will allow it to continue its present accounting treatment for capital costs associated with the construction of Trimble County Unit No. 1.

Company and Consumer Needs

LG&E witnesses Mr. Royer and Mr. Wright testified about the steps LG&E has taken to improve efficiency and mitigate increases in its operating costs. The Commission realizes that the environment in which LG&E operates has changed drastically in recent years and that the steps it has taken are in direct response to these changes. However, the evidence of record leads the Commission to believe that there is room for further improvement in these areas. As was stated in the Order in Case No. 8045, General Telephone, before this Commission:

> ...The Governor of the Commonwealth, when faced with expenditures in excess of expected revenues, has not sought tax increases (rate increases) every five or six months. Instead, difficult decisions have been made as to where expenditures could be reduced without eliminating essential services.
>
> The Commission expects this same attitude toward controlling costs by the utilities it regulates.84/

LG&E deferred this application for as long as it felt possible, and it should be commended for doing so. However, while LG&E claims to have "tightened its belt," it has managed to operate in the black and at the same time provide an increased dividend to its shareholders.

The Commission is not unsympathetic to LG&E's needs; however, we are required by statute to also consider the needs of the consumers it serves. At a time of record unemployment and a depressed economy in LG&E's service area,

these needs are significant, and the Commission must strive to balance those needs with the needs of LG&E. In balancing the interests, the Commission has considered LG&E's failure to earn its allowed rate of return and how that failure has been affected by unprecedented inflation and record high interest rates. The Commission has also considered the requests of Mayor Sloane and Alderman Meeks, and of Commissioner Malone and Reverend Flynn--and by the many others who spoke in Louisville on December 1, 1982, for consideration of the plight of LG&E's consumers. The Commission has found that an increase in rates is necessary, but that a more moderate increase than was requested by LG&E will be sufficient. The Commission is of the opinion that the rates approved herein will be fair, just and reasonable, and will permit LG&E to furnish adequate, efficient and reliable service to its customers.

Compensation for Intervenors

Section 122 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") allows for compensation for the costs of participation or intervention to consumer representatives who substantially contribute to decisions on PURPA-related matters. In the brief of the Residential Intervenors, the issue of compensation for intervenors is raised.[85] This Commission is reconsidering its current position on this matter and may undertake a generic proceeding to address the issue.

SUMMARY

The Commission, having considered the evidence of record, 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 $659,257,255.

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 March 1, 1983.

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

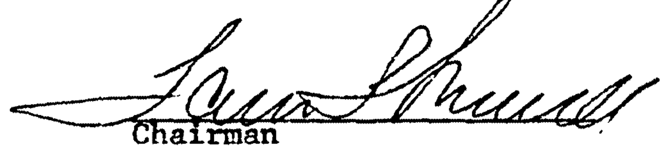
IT IS FURTHER ORDERED that there be a thorough study of LG&E's load forecasting, and of such related issues as the benefits to be realized from a cost-effective conservation program; the most prudent course to follow concerning the Cane Run units; the financially sound course to pursue with regard to the Trimble County Unit No. 1; and the extent to which it would be economically beneficial for LG&E to purchase power from and/or sell power to neighboring utilities,

such study to be undertaken by an independent consulting firm to be selected by the Commission and compensated by LG&E, with the results of such study, and recommendations, to be contained in a report to the Commission, with copies made available to LG&E and other interested parties.

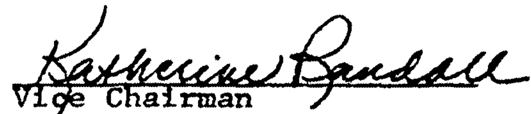
IT IS FURTHER ORDERED that within 30 days from the date of this Order LG&E shall file with the Commission its revised tariff sheets setting out the rates approved herein.

Done at Frankfort, Kentucky, this 2nd day of March, 1983.

PUBLIC SERVICE COMMISSION



Chairman



Vice Chairman

Commissioner

ATTEST:

Secretary

FOOTNOTES

1/ Wilkerson Exhibit 8, page 1.

2/ Wilkerson Testimony, page 17.

3/ Transcript of Evidence ("T.E."), Volume I of IV, January 3, 1983, page 187.

4/ Response to Commission Order dated December 16, 1982, Item 3.

5/ Calculated from Response to Commission Order dated December 16, 1982, Item 2, pages 2-4.

6/ *Ibid.*, pages 2-8.

7/ Wilkerson Revised Exhibit 5.

8/ Weaver Testimony, page 55.

9/ *Ibid.*

10/ Weaver Exhibit CGW, Statement 15, page 2.

11/ Calculated from 30-year normal degree days--Attachments to Hart Revised Exhibits 6 and 7.

12/ *Ibid.*

13/ T.E., Volume III of IV, January 5, 1983, pages 136-137.

14/ Notice of Adjustment of Rates, Exhibit No. 1, page 13.

15/ T.E., Volume II of IV, January 4, 1983, pages 79-80, 85.

16/ T.E., Case No. 8284, April 13, 1982, page 6.

17/ *Ibid.*, pages 8 and 22.

18/ *Ibid.*, page 13, and Walker Exhibits A, B, C and D.

19/ Response to Commission Order dated October 15, 1982, Item 20.

20/ Hart Exhibit 4.

21/ $159,796,974 less $159,561,988.

22/ Response to Commission Order dated September 16, 1982, item 10E, pages 1-2.

23/ T.E., Volume I of IV, January 3, 1983, page 196.

24/ *Ibid.*, page 195.

25/ Response to Commission Order dated October 15, 1982, Item 10F, page 1.

26/ T.E., Volume III of IV, January 5, 1983, page 81.

27/ *Ibid.*, page 141.

28/ Response to AG's Supplemental Request dated November 12, 1982, Item 30.

29/ T.E., Volume I of IV, January 3, 1983, pages 174-175.

30/ Price Testimony, pages 18-19.

31/ Wilkerson Exhibit 5.

32/ Response to Commission Order dated October 15, 1982, Item 17, page 1.

33/ Wilkerson Testimony, page 17.

34/ *Ibid.*

35/ Wilkerson Revised Exhibit 5.

36/ *Ibid.*

37/ Weaver Exhibit CGW, Statements 16 and 17.

38/ Weaver Testimony, page 56.

39/ *Ibid.*

40/ The annualized cost of each preferred issue is calculated by multiplying the amount outstanding by the cost rate at issue. The total annualized cost is divided by the total amount outstanding.

41/ Monteau Testimony, page 22.

42/ *Ibid.*

43/ *Ibid.*, page 24.

44/ *Ibid.*

45/ *Ibid.*, page 26.

46/ Supplement to Monteau Schedule 13, page 2.

47/ Notice of Reduction of Amount Requested, December 20, 1982, page 1.

48/ Monteau Testimony, Schedule 13, page 2.

49/ Monteau Data Response, page 1 of 5, from request at hearing and T.E., Volume III of IV, January 5, 1983, page 44.

50/ Weaver Testimony, page 65.

51/ Monteau Testimony, Schedule 11, page 1.

52/ Initial Staff Request, Item 41, Schedule 1, pages 1-3.

53/ Weaver Testimony, page 2.

54/ Ibid., page 8.

55/ Respone to Airco and duPont Data Request No. 1, Item 9, pages 110-112.

56/ Ibid.

57/ Ibid.

58/ T.E., Volume II of IV, January 4, 1983, page 171.

59/ Brief of Airco, pages 8-9.

60/ Hart Testimony, page 5.

61/ Ibid.

62/ Hart Exhibit 1.

63/ Brubaker Exhibit MEB-2, Schedule 10.

64/ Hart Testimony, pages 4 and 5.

65/ Wright Testimony, page 7.

66/ T.E., Volume III of IV, January 5, 1983, page 128.

67/ Ibid., page 127.

68/ T.E., Volume II of IV, January 4, 1983, page 58.

69/ Wright Testimony, page 6.

70/ T.E., Volume I of IV, January 3, 1983, page 9.

71/ Ibid., page 27.

72/ Ibid.

73/ Wright Testimony, pages 6-7.

74/ T.E., Volume III of IV, January 5, 1983, page 131.

75/ *Ibid.*, page 111.

76/ *Ibid.*, page 132.

77/ *Ibid.*, page 133.

78/ *Ibid.*, page 152.

79/ *Ibid.*

80/ Rhodes Testimony, pages 9-10.

81/ *Ibid.*, page 24.

82/ Rhodes Exhibit SFR, Schedule 14.

83/ *Ibid.*, Schedule 15.

84/ Order in Case No. 8045, General Telephone Company of Kentucky, entered May 15, 1981, page 20.

85/ Residential Intervenors' Brief, pages 6-8.

APPENDIX A

APPENDIX TO AN ORDER OF THE PUBLIC SERVICE COMMISSION IN CASE NO. 8616 DATED MARCH 2, 1983.

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 the authority of the Commission prior to the date of this Order.

ELECTRIC SERVICE

RESIDENTIAL SERVICE*
(RATE R)

Rate:

Customer Charge: $2.90 per meter per month.

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

First 600 kilowatt-hours per month	5.355 ¢ per Kwh
Additional kilowatt-hours per month	4.030 ¢ per Kwh

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

All kilowatt-hours per month	5.889 ¢ per Kwh

WATER HEATING RATE*
(RATE WH)

Rate: 4.182 ¢ per kilowatt-hour.

Minimum Bill: $1.80 per month per heater.

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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.

GENERAL SERVICE RATE*

(RATE GS)

Rate:

Customer Charge:

$3.50 per meter per month for single-phase service
$7.00 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 5.850 ¢ per Kwh

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

All kilowatt-hours per month 6.603 ¢ 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 85¢ 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 4.203¢ 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.

Minimum Bill:

$6.10 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.

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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.

DIRECT CURRENT POWER*
(RATE DC)

Rate:

Customer Charge: $7.40 per meter per month.

All kilowatt-hours per month	6.819 ¢ per Kwh

Minimum Bill:

$2.67 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:

Mercury Vapor	Rate Per Light Per Month
100 watt*	$ 5.65
175 watt	6.50
250 watt	7.70
400 watt	9.40
1000 watt	18.80
400 watt floodlight	9.40
1000 watt floodlight	18.80
High Pressure Sodium Vapor	
250 watt	$11.30
400 watt	13.35
400 watt floodlight	13.35

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

OUTDOOR LIGHTING SERVICE - UNDERGROUND

Rates:

Mercury Vapor	Rate Per Light Per Month
100 watt-colonial or modern design top mounted	$11.30
175 watt-colonial or modern design top mounted	$11.90
Special Wood Poles (Overhead)	$ 1.15

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

PUBLIC STREET LIGHTING SERVICE
(RATE PSL)

Rates:

Type of Unit	Support	Rate Per Light Per Year	
Overhead Service			
100 Watt Mercury Vapor (open botton fixture)	Wood Pole	$ 50.50	(1)
175 Watt Mercury Vapor	Wood Pole	74.00	
250 Watt Mercury Vapor	Wood Pole	87.50	
400 Watt Mercury Vapor	Wood Pole	105.00	(2)
400 Watt Mercury Vapor	Metal Pole	181.00	
400 Watt Mercury Vapor Floodlight	Wood Pole	105.00	
1000 Watt Mercury Vapor	Wood Pole	222.00	
1000 Watt Mercury Vapor Floodlight	Wood Pole	222.00	
250 Watt High Pressure Sodium	Wood Pole	120.00	
400 Watt High Pressure Sodium	Wood Pole	145.00	
400 Watt High Pressure Sodium Floodlight	Wood Pole	145.00	
Underground Service			
100 Watt Mercury Vapor Top Mounted		134.00	
175 Watt Mercury Vapor Top Mounted		141.00	
175 Watt Mercury Vapor	Metal Pole	145.00	
250 Watt Mercury Vapor	Metal Pole	163.00	
400 Watt Mercury Vapor	Metal Pole	181.00	
400 Watt Mercury Vapor	Alum. Pole	235.00	
400 Watt Mercury Vapor on State of Ky. Alum. Pole		134.00	
250 Watt High Pressure Sodium Vapor	Metal Pole	217.00	
250 Watt High Pressure Sodium Vapor	Alum. Pole	246.00	
400 Watt High Pressure Sodium Vapor	Metal Pole	236.00	
400 Watt High Pressure Sodium Vapor	Alum. Pole	265.00	
250 Watt High Pressure Sodium Vapor on State of Ky. Alum. Pole		145.00	(3)
1500 Lumen Incandescent 8-1/2"	Metal Pole	65.00	(3)
6000 Lumen Incandescent	Metal Pole	126.00	

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

LARGE COMMERCIAL RATE*
(RATE LC)

Rate:

Customer Charge: $14.50 per delivery point per month.

Demand Charge:

	Secondary Distribution	Primary Distribution
Winter Rate: Applicable during 8 monthly billing periods of October through May)		
All kilowatts of billing demand	$ 6.14 per Kw per month	$ 4.76 per Kw per month
Summer Rate: (Applicable during 4 monthly billing periods of June through September)		
All kilowatts of billing demand	$ 9.04 per Kw per month	$ 7.37 per Kw per month

Energy Charge: All kilowatt-hours per month 3.022 ¢ per Kwh

INDUSTRIAL POWER RATE*
(RATE LP)

Rate:

Customer Charge: $36.20 per delivery point per month.

Demand Charge:	Secondary Distribution	Primary Distribution	Transmission Line
All kilowatts of billing demand	$ 7.61 per Kw per month	$ 5.95 per Kw per month	$ 4.94 per Kw per month

Energy Charge: All kilowatt-hours per month 2.611 ¢ per Kwh

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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.

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

Demand Charge:

Primary Power (28,500 KW)	$9.84 per Kw per month
Secondary Power (Excess KW)	$4.92 per Kw per month

Energy Charge:

Primary & Secondary Power	1.840 ¢ per Kwh

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

Demand Charge:

All KW of billing demand	$9.48 per Kw per month

Energy Charge:

All KWH	1.957 ¢ per Kwh

SPECIAL CONTRACT FOR ELECTRIC SERVICE TO LOUISVILLE WATER COMPANY*

Demand Charge:

KW of billing demand	$6.50 per Kw per month

Energy Charge:

All KWH per month	2.069 ¢ 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	$4.82 per Kw per month

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

All kilowatts of billing demand	$6.71 per Kw per month

Energy Charge: All kilowatt-hours per month 2.516 ¢ per Kwh

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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.

STREET LIGHTING ENERGY RATE
(RATE SLE)

Rate:

4.014¢ net per kilowatt-hour

TRAFFIC LIGHTING ENERGY RATE
(RATE TLE)

Rate:

5.207 ¢ net per kilowatt-hour

Minimum Bill:

$1.35 net per month for each point of delivery

GAS SERVICE

GENERAL GAS
(RATE G-1)

Rate:

Residential Customer Charge: $2.30 per month.
Non-Residential Customer Charge: $4.50 per month.

48.105 ¢ per 100 cubic feet.

Minimum Bill:

The customer charge.

GENERAL GAS RATE - LARGE VOLUME SPACE HEATING
(RATE G-1A)

Delete Tariff. Incorporate Customers served into Tariff General Gas (Rate G-1).

SUMMER AIR CONDITIONING SERVICE UNDER GAS
(RATE G-1)

Rate:

For the "Summer Air Conditioning Consumption" determined in the manner hereinafter prescribed, the rate shall be 47.063 cents per 100 cubic feet, subject to the "Purchased Gas Adjustment" and the Prompt Payment Provision" incorporated in Rate G-1 as applicable. All monthly consumption other than "Summer Air Conditioning Consumption" shall be billed at the regular charges set forth in Rate G-1.

COMMERCIAL AND INDUSTRIAL GAS
(RATE G-2)

Delete Tariff. Incorporate Customers served into Tariff General Service.

SEASONAL OFF-PEAK GAS
(RATE G-6)

Rate:

Customer Charge: $7.30 per delivery point per month.

47.060 ¢ per 100 cubic feet.

Minimum Bill:

The customer charge.

UNCOMMITTED GAS SERVICE
(RATE G-7)

Rate:

47.060 ¢ per 100 cubic feet.

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

Rate:

Customer Charge: $7.30 per delivery point per month.

48.024 ¢ per 100 cubic feet.

Minimum Bill:

The customer charge.

SUMMER AIR CONDITIONING SERVICE UNDER GAS
(RATE G-8)

Rate:

For consumption recorded during the aforesaid five billing periods the rate shall be 47.063 cents per 100 cubic feet, subject to the "Purchased Gas Adjustment" and to the "Prompt Payment Provision" incorporated in Rate G-8.

TRANSPORTATION OF CUSTOMER-OWNED GAS (RATE T-1)

Charges:

The charge for service under this rate schedule shall be 15.0 cents for each Mcf of gas transported. This charge may be increased or reduced by appropriate filings made in accordance with law and the rules of the Public Service Commission. 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

Demand Charge:

$ 1.45 per month per Mcf of billing demand.

Commodity Charge:

$ 4.6195 per Mcf delivered.

Purchased Gas Adjustment

Base Supplier Rate

	Demand	Commodity
Texas Gas Transmission Corporation Rate Schedule G-4	$ 6.90	364.62¢

Purchased Gas Adjustment Applicable to rate schedules approved herein 0.00¢ per 100 cu. ft. as the Base Supplier.

The purchased gas adjustment of LG & E should be adjusted to the following:

PGA corresponding to Base Supplier	0.000¢
Refund Factor effective September 1, 1981, and continuing for 12-months or until, Louisville has discharged its refund obligation from Case No. 7799-D	(.670)
Refund Factor effective December 1, 1981, and continuing for 12-months or until Louisville has discharged its refund obligation from Case No. 7799-E	(.074)
Total Adjustment per 100 cubic feet	(.744¢) Refund