CASE NUMBER:

99-430

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

CERTIFICATE OF SERVICE

RE: Case No. 1999-430
LOUISVILLE GAS AND ELECTRIC COMPANY

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed attested copy of the Commission's Order in the above case was served upon the following by U.S. Mail on September 29, 2000.

See attached parties of record.

Stephanie J. Bell

Secretary of the Commission

SB/lc
Enclosure

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN)
OF LOUISVILLE GAS AND ELECTRIC COMPANY) CASE NO. 99-430
AND KENTUCKY UTILITIES COMPANY)

O R D E R

The Commission initiated this proceeding in order that its Staff might conduct a review of the 1999 integrated resource plan ("IRP") submitted by Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") pursuant to 807 KAR 5:058. Intervening in this case were the Attorney General's Utility and Rate Intervention Division and the Natural Resources and Environmental Protection Cabinet, Division of Energy.

Pursuant to 807 KAR 5:058, Section 12, the Commission Staff has issued a report on its review of the LG&E/KU 1999 IRP. Issuance of this report concluded the Staff's review of the LG&E/KU 1999 IRP.

IT IS THEREFORE ORDERED that this case be and it hereby is closed.

Done at Frankfort, Kentucky, this 29th day of September, 2000.

By the Commission

ATTEST:

Stephan Bell for Tom Dorman

Executive Director

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September 22, 2000

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Re: Case No. 99-430
Louisville Gas & Electric Company and Kentucky Utilities Company

Dear Madams and Sirs:

Attached is a copy of the Commission Staff Report on the Joint Integrated Resource Plan of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") which has been filed into the record of the above-referenced case. This report, prepared pursuant to 807 KAR 5:058, Section

12(3), summarizes the Staff's review of the LG&E/KU 1999 integrated resource plan filing and related information.

Sincerely,

Thomas M. Dorman
Executive Director

Attachment

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M E M O R A N D U M

TO: Main Case File - Case No. 99-430

FROM: Case No. 99-430 Team

DATE: September 22, 2000

SUBJECT: Commission Staff Report

Attached for filing in this case is the Commission Staff Report on the 1999 Integrated Resource Plan of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"). This report, prepared pursuant to 807 KAR 5:058,Section 12(3), summarizes the Staff's review of the LG&E/KU 1999 integrated resource plan.

CC: Parties of Record

Kentucky Public Service Commission

Staff Report

On the Joint

Integrated Resource Plan Report

Of Louisville Gas and Electric

Company and Kentucky Utilities Company

Case No. 99-430

September 2000

Section 1

INTRODUCTION

In 1990, the Kentucky Public Service Commission ("Commission") established an integrated resource planning (IRP) process to provide for regular review by the Commission Staff of the long-range resource plans of the six major electric utilities under its jurisdiction. The Commission's goal in establishing the IRP process was to ensure that all reasonable options for the future supply of electricity were being examined and puirsued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.

The Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") submitted their 1999 Joint IRP to the Commission on November 22, 1999. The report submitted by the Companies provided their plan to meet customers' requirements over the period 1999-2013.

LG&E and KU are investor-owned public utilities supplying electricity and natural gas to customers primarily in Kentucky. Both are subsidiaries of LG&E Energy Corporation. LG&E Energy Corporation and KU Energy Corporation completed a merger transaction on May 4, 1998, at which time KU became a subsidiary. As the owners and operators of interconnected electric generation, transmission, and distribution facilities, the Companies achieve economic benefits through operation as a single interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

Subsequent to the filing of the 1999 Joint IRP, LG&E Energy Corporation announced in February of 2000 that it was being acquired by PowerGen, a British utility with international operations. The acquisition of LG&E Energy would be PowerGen's first acquisition in the United States, although PowerGen has announced that it intends to pursue additional U.S. transactions in the future. At the time of this staff report, the merger has not yet received all necessary regulatory approvals, but it has been approved by this Commission.

LG&E supplies electricity and natural gas to customers in the Louisville metropolitan area. It provides electric service to more than 360,000 customers in Louisville and 16 surrounding counties covering approximately 700 square miles.

KU supplies electric service to more than 478,000 retail customers in a service area which covers approximately 6,600 non-contiguous square miles in 77 Kentucky counties and 5 southwestern Virginia counties. KU also sells electric energy at wholesale for resale to 11 municipalities in Kentucky, Berea College (a privately-owned utility serving the city of Berea) and Pitcairn, Pennsylvania.

The purpose of this report is to review and evaluate the Joint IRP in accordance with the requirements of 807 KAR 5:058, Section 12(3), which requires the Commission Staff to issue a report summarizing its review of each IRP filing and offer suggestions and recommendations to be considered in subsequent filings. Staff recognizes that resource planning is an ongoing and dynamic process. Thus, this review has been designed to offer suggestions to LG&E/KU on how to improve their plan in the future. Specifically, the Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The selected plan represents the least-cost, least risk plan for the ultimate customers served by the Companies, recognizing the need to achieve a balance between the interests of ratepayers and shareholders.

The report also has an incremental component, noting any significant changes from LG&E's most recent filing in 1993 and KU's most recent filing in 1996.

Based on a forecasted average annual growth rate of 1.9% per year over the 1999-2013 forecast period, the Companies will require new resource additions for each year of the forecast period after 1999. The supply side resources consist of 300 MW of Purchased Power in 2000, a combination of CTs and DSM programs for each of the years from 2001-2006, and a CT addition for each year from 2006-2013.

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, provides a review of the Companies' projected load requirements and load forecasting methodology.
- Section 3, Demand-Side Management (DSM), summarizes the Companies' evaluation of DSM opportunities.
- Section 4, Supply Side Resource Assessment, focuses on supply side resources available to meet the Companies' requirements.
- Section 5, Integration and Plan Optimization, discusses the Companies' assessment of supply and demand-side options into a resource plan.

Section 2

LOAD FORECASTING

INTRODUCTION

This section summarizes the methodology and results of the Companies' load forecasts, describes changes that have occurred since the last IRP filings (in 1993 for LG&E, and in 1996 for KU) and discusses the reasonableness of the current approach. Due to differences in the historical data series for the two companies, the energy and demand forecasting process for the 1999-2013 period has maintained existing forecast processes for each utility. For the combined system, the separately estimated demand forecasts are not considered to be strictly additive due to some slight non-coincidence in system peaks.

METHODOLOGY

Forecasting future energy and demand is important for the planning and control of the Companies, as the forecast is a tool for decisions regarding construction of power plants, transmission lines and substations. The desired outcome of the forecasting process is a reasonable estimate so that the Companies can continue to provide adequate and reliable service at the lowest reasonable cost.

For LG&E, an econometric forecasting approach was used to develop the forecast to satisfy two critical requirements. First, the econometric approach combines the economic and demographic factors that determine sales in a rational manner. National, regional, and local drivers for LG&E sales were organized in a top-down approach, meaning that national economic conditions affect regional and local conditions, which in turn influence LG&E sales. This approach was used to produce a base case forecast and optimistic and pessimistic growth scenarios needed in the sensitivity analysis of the various resource acquisition plans being studied. Second, this approach quantified cause and effect relationships between electric sales and peak demand, and the economic factors that influence sales and peak demand. The Consumer Price Index, national income deflator, and industrial productivity changes were the national factors, while the local influences were employment, population, households, personal income, weather, and the price of electricity. Weather data was received from the National Climatic Data Center (NCDC), while the electric price forecast was determined internally.

Once econometric relationships were estimated, the electric sales and peak demand forecasts were produced by standard econometric procedures. First, forecasts of explanatory variables were obtained, with forecasts of national economic variables purchased from WEFA Group, Inc., a nationally recognized economic consulting firm used by the Companies and many other utilities (Both companies use WEFA data to insure consistency within the planning function). Regional economic and demographic forecasts were prepared by the University of Louisville (UL) and the University of Kentucky (UK), and a short-term economic outlook for the Louisville MSA was provided by Regional Financial Associates, Inc. The regional forecasts were constructed so that they were consistent with, and driven by, the national economic forecasts. Finally, LG&E's electric sales and peak demand forecasts were produced by feeding the forecast driver values into and solving the econometric equations. Separate models were developed for energy sales and peak demand, and the independently produced sales forecasts and peak demand forecasts were jointly evaluated for reasonableness by reviewing the load factors calculated from the forecasts.

For KU, its energy forecast addresses three basic jurisdictional groups. These groups are Kentucky-Retail, which accounted for 85.1% of predicted sales for 1999; Virginia-Retail, which accounted for 4.8% of predicted sales; and Wholesale sales to 13 customers, which accounted for 10.1% of predicted sales. The energy forecast as generated within each group is disaggregated by classes (e.g., Residential, Commercial, and Industrial) in order to address the unique characteristics identifiable within each class. The number of customers as well as Gigawatt-Hours (GWH) are forecasted, with some models based on a Kilowatt-Hours (KWH) per customer forecast. Econometric and end-use modeling techniques were used with minimal use of trending.

WEFA-generated national forecast data is fed to the UK State Econometric Model to produce forecasts of value-added output, employment, income, and population. This state forecast data as well as national forecasts for total employment and selected industrial production indices are fed to the KU Service Territory Economic Model (KUSTEM) to generate forecasts of sector level value-added output, employment, income, population and households for five KU regions. The regional information is then summed to create system-level class forecast drivers.

Because coal mining is an important industry in the KU service territory, a coal production forecast for East and West Kentucky is obtained from Resource Data International (RDI). In addition, weather and electric prices are local variables that are also included in the forecast development process where appropriate. As with LG&E, KU obtains its weather data from NCDC, and determines its electric price forecast internally. KU also relies on company-collected report and survey data as inputs to the process, enabling the company to estimate the percentage of new residential customers choosing the Full Electric Residential Service Rate by type of housing, the availability of gas at new hookups, the mix of residential housing types on the system, the approximate saturation levels of various appliances, and the sales history by key Standard Industrial Classification (SIC) codes.

The KU Peak Demand forecast is calculated from the class-level energy forecast, actual and assumed data on class and customer-level load shapes, impacts on system load associated with KU's Curtailable Service Rider (CSR) rate, weather data, and losses. The energy, load shape and weather information is combined and customer and class-level demand forecasts are developed using the Hourly Electric Load Model (HELM) developed by EPRI. The annual class demand profiles are summed within HELM to create the system demand forecast.

For the combined companies, the energy forecasts for the individual companies are combined through a simple additive process. The combined-company peak demand forecast is developed by appending the LG&E system-level load forecast to the KU hourly load forecast within the HELM model. Due to some slight non-coincidence, the individual company peaks are not additive in arriving at the combined demand forecast. The application of the HELM methodology allows for the separate company load forecasts to be properly aligned.

Key Assumptions

For LG&E, the following key economic and demographic assumptions are the primary drivers of its energy and demand forecast:

- Service area population will grow from 741,318 in 1999 to 797,321 in 2013, an average annual growth rate of 0.5%.
- Number of persons per residential customer count will decrease from 2.32 in 1999 to 2.17 in 2013.
- Real per capita personal income in the Louisville MSA will increase by an average annual rate of 1.9%, from $24,212 in 1999 to $31,593 in 2013.
- Trade and service industry employment in the Louisville MSA will grow annually by 1.1%, while manufacturing employment will slightly decline for the next 15-year period.
- Future climate is reflected by the weather values averaged for the most recent 20-year period.
- The saturation rate of residential air conditioners will increase from 94.9% in 1999 to 99.0% in 2013.

For KU, its key assumptions are as follows:

- Annual U.S. Real Gross Domestic Product growth will average 2.0 percent over the next five years and 1.9 percent over the next 15 years.
- Households in KU-served counties are predicted to increase at a 1.8 percent annual average rate over the next five years, and 1.3 percent over the next 15 years.
- Future climate is reflected by the weather values averaged for the most recent 20-year period.
- Over the next five years, about 45 percent of all new households in KU-served counties will locate in KU territory. From 2000 to 2010, the percentage slips to about 42 percent.
- Residential customers should increase at a 1.7 percent annual rate for the next five years, and at a 1.1 percent annual rate over the next 15 years.
- Discounted for inflation, the real retail price of electricity is expected to decrease over the next 15 years, while the nominal residential price of gas is predicted to rise.
- KU service territory industrial output should increase at an annual rate of 3.7 percent for the next five years and 3.5 percent for the next 15 years.
- KU service territory commercial employment should increase at an average annual rate of 1.6 percent for the next five years and 1.9 percent over fifteen years.

- East Kentucky coal production should rise at a 0.6 percent average annual rate for both the next five-year and 15-year periods. West Kentucky coal production should decline at an average annual rate of 0.1 percent for the next five years, and increase at an average annual rate of 0.7 percent over the next 15 years.
- Appliance efficiency standards as set by the National Energy Policy Act of 1992 are reflected in the forecast.

Results

On a combined basis, sales are expected to grow from 29,358 GWH in 1999 to 33,083 GWH in 2004, averaging 2.4 percent compound annual growth. By 2013, combined sales are expected to reach 38,906 GWH, with growth averaging 1.9 percent per year over the forecast horizon.

Combined company native peak demand is predicted to grow from 6,350 MW in 1999 to 7,127 MW in 2004, an increase of 777 MW with an average annual growth rate of 2.3 percent. By 2013, combined company peak demand is predicted to reach 8,397 MW, a growth of 2,047 MW with an average annual growth rate of 1.9 percent annually. The combined company is a summer peaking utility.

Uncertainty Analysis

Future values of the explanatory variables included in the forecasting models may vary from those used in the forecast. To address this uncertainty, both LG&E and KU develop optimistic and pessimistic scenarios to support sensitivity analysis of the various acquisition plans being studied. For LG&E, the key uncertainty analysis variables are population, per capita personal income, employment by industry, and electricity price by class. The WEFA Group provided optimistic and pessimistic forecasts for national variables, which were processed down to the metro level for LG&E and through the UK state econometric model and the KUSTEM model for KU.

For LG&E, the optimistic and pessimistic forecasts of energy sales range from 15,776 GWH to 14,673 GWH in 2013, in contrast to the baseline forecast of 15,190 GWH. LG&E's optimistic and pessimistic forecasts of peak demand range from 3,625 MW to 3,255 MW in 2013, in contrast to the baseline forecast of 3,392 MW. In the near-term period to 2004, the optimistic and pessimistic forecasts of peak demand range from 2,975 MW to 2,798 MW, in contrast to the baseline forecast of 2,865 MW.

For KU, the optimistic and pessimistic forecasts of energy sales range from 25,370 GWH to 23,676 GWH in 2013, in contrast to the baseline forecast of 24,519 GWH. KU's optimistic and pessimistic forecasts of peak demand range from 5,234 MW to 4,874 MW in 2013, in contrast to the baseline forecast of 5,048 MW. In the near-term period to 2004, KU's optimistic and pessimistic forecasts of peak demand range from 4,368 MW to 4,232 MW, in contrast to the baseline forecast of 4,300 MW.

Discussion of Reasonableness

In general, Staff is satisfied with the forecasting of the Companies. In its March 1999 Staff Report on KU's 1996 IRP, Staff made the following recommendations relative to load forecasting for KU's consideration in preparing its next IRP filing:

- KU should continue the development of its demand forecast using EPRI's HELM model to better enable it to account for changing end uses in its various sales sectors.
- KU should report on its work to develop a service area demographic and economic forecast that will produce region specific forecasts of model drivers.
- KU should, to the extent possible, report on and reflect in its forecasts, the impacts of increasing competition in the electric industry.
- KU should attempt, either in the body of its forecasts, or in its uncertainty analysis, to incorporate the impacts of potential environmental costs such as those associated with EPA's recent decision to impose NOx reductions on sources in the eastern United States.

In commenting upon LG&E's most recent IRP in its Staff Report of March 1995, Staff made the following recommendations on load forecasting to LG&E:

- Expand the peak demand analysis, possibly using additional sectoral or end-use detail.
- Explicitly analyze the issue of fuel choice for space heating and cooling, particularly with respect to the competitiveness of heat pumps.

In this IRP, Staff is satisfied that the Companies have adequately responded to both sets of recommendations. However, given the potential impact of competition and future environmental requirements, the Companies should continue to examine and report on these issues and how they are incorporated into future load forecasts.

Recommendations

- The Companies should continue to examine and report on the potential impacts of increasing competition and future environmental requirements and how these issues are incorporated into future load forecasts.
- Due to the merger between the two companies and the pending PowerGen combination, the Companies should continue to pursue efforts to integrate their forecasting processes and report on these efforts in their next IRP filing.

Section 3

DEMAND SIDE MANAGEMENT

Introduction

This section summarizes the DSM assessment included in the Companies' 1999 IRP. According to the IRP, the Companies evaluate future electric service requirements of customers with balanced consideration of demand-side or supply-side resource options. The Companies formed an interdepartmental team, which brainstormed to identify a broad range of DSM alternatives, and each alternative was evaluated using a two-step screening process. The first step was qualitative in nature, and consisted of evaluating each alternative based upon four criteria. The alternatives that passed the first step underwent a second step of screening that was quantitative in nature. That quantitative process was broken down into two separate phases, and the DSM programs that passed the process were then aggregated into three DSM programs to compete with supply-side alternatives in the integrated analysis. The remainder of this section describes the process and its results in greater detail.

Screening Process and Results

The interdepartmental DSM team identified a list of 82 alternatives to be evaluated, and criteria were defined to facilitate an objective evaluation of those alternatives. Based upon the Companies' objectives to provide low cost, reliable energy and upon comments from the previous PSC Staff Reports, four criteria were selected. Then, weights or values were assigned to each of the criteria, with those criteria deemed most important to developing a successful DSM program being assigned the highest weights. The two most important criteria were customer acceptance and the effectiveness of each DSM alternative in meeting load shape objectives. Each potential DSM option was evaluated, based on a scale of 0 to 4, using the four criteria. This system resulted in 16 DSM options to be further analyzed. Of those 16 programs, nine are targeted to residential customers, five are targeted to commercial customers, and two are targeted to industrial customers. All of these options were then evaluated in the quantitative screening process.

For the quantitative process, the options were modeled in more detail using EPRI's DSManager software, which is a PC-based software package that determines the cost effectiveness of DSM options by modeling their costs and benefits over a period of time. For each modeled option, load shapes using a typical 48-day format to represent a year were developed for scenarios with and without the DSM option. However, not every DSM option required 48 daily load shapes, as some load drivers such as air conditioners are not used throughout the year. DSManager utilizes marginal energy costs (determined by a detailed production-costing model called ENPRO) to estimate the change in production costs resulting from the implementation of each DSM option.

DSManager calculates the net present value of the quantifiable costs and benefits assignable to both the Companies and the customers participating in a DSM program. The present value for each option is calculated and reported as the costs and benefits using what are known as the "California Tests." While there are five such tests, the Companies used only two - the participant and total resource cost (TRC) tests - to screen DSM options. The participant test includes changes in all costs and benefits to the DSM customer. The TRC test combines the ratepayer impact measure (RIM) test and participant test and indicates overall benefits of the DSM option to the average customer, whereas the RIM test considers all impacts to the non-participants.

The quantitative screening was set up in two phases, with the first phase ignoring the cost to administer the program and assuming that the program had only one participant per company. If the benefits of a program do not exceed the cost of the program without the administrative cost, then it will not pass with a higher penetration of customers and the added burden of administrative costs. Of the 16 options evaluated, 11 passed the TRC in this phase and were further evaluated in the second phase of the quantitative analysis. In the second phase, the administrative costs and the expected penetration levels for each company were considered for the 11 remaining options.

The options which passed the quantitative screening were the following:

- Air conditioning direct load control program – For residential and commercial customers, direct load control of central air conditioners and heat pumps would be promoted to reduce temperature-sensitive peaks caused by the use of air conditioning equipment. Radio-controlled relay switches are used to interrupt power to an air conditioner or heat pump compressor unit during high-demand periods.

- Pool pump direct load control program – For residential customers, this program would promote the reduction of summer peaks by offering customers a monthly credit to their electric bill for each of the four summer months. This program was combined with the residential and commercial air conditioning direct load control programs listed above to compete with supply-side alternatives in the integrated analysis.

- High efficiency outdoor lighting program – For residential customers, this program would encourage customers to install high intensity discharge lighting fixtures which cost more to install but have considerable energy savings.

- High efficiency lighting program – For commercial and industrial customers, these programs would target them because the coincidence factor with the Companies' system peaks is high. Commercial customers are the best targets for these programs because lighting typically represents a third of their total electricity cost. These programs were combined with the residential lighting program (as well as the water heater program mentioned below) to compete with supply-side alternatives in the integrated analysis.

- Water heater wrap up program – This program would encourage residential customers to install water heater blankets to improve the insulation of their electric water heater. This program was combined with the lighting programs listed above for analysis purposes to create a single "Efficient Lighting" program to compete with supply-side alternatives in the integrated analysis.

- Standby generation program – For commercial and industrial customers, these programs would allow the Companies to defer peaking capacity additions by compensating customers who agree to run generators that they own, at the Companies' request, for up to 250 hours per year. Customers participating in the program would be required to either isolate their generators from the Companies' system through the use of open transfer switches, or install paralleling equipment which meets the Companies' protective standards. The commercial and industrial programs were combined to create one Standby Generation program to compete with supply-side alternatives in the integrated analysis.

The result was that the nine programs which passed the quantitative screening process were aggregated into three DSM programs before competing with the supply-side alternatives in the integrated analysis. Any DSM program that passes the integrated analysis would be put through a rigorous design phase and would begin as a pilot program.

Intervenor Comments

The Kentucky Division of Energy (DOE) provided extensive comments relative to the Companies' DSM efforts. They applauded the Companies' increased efforts to promote DSM, especially LG&E's establishment of a non-regulated energy service company, and they emphasized that the overall trend as represented in the 1999 IRP is in a positive direction. Next, DOE provided its vision of a well-functioning market for energy services in the future.

DOE also offered the following specific criticisms of the Companies' DSM as reflected in the 1999 IRP:

- Only a limited number of options were considered.
- Category confusion, in that different technologies were lumped together, may have reduced the meaning of the results.
- The qualitative DSM screening method was faulty, and the threshold ratings cutoff point was excessively stringent (see AG comments below).

DOE recommended that the Companies initiate a comprehensive market transformation program in the new commercial construction sector; that they use local integrated resource planning to potentially defer transmission and distribution upgrades; that they promote cogeneration and other distributed generation; that they support statewide and regional market transformation initiatives, defined as "planned interventions in the market that lead to longer-lasting impacts than traditional utility-sponsored DSM programs that depend on ongoing rebates for their effectiveness"; and that they launch a Kentucky design initiative to improve the quality of energy system design and engineering.

In the Companies' comments in reply to DOE's critique, they characterized DOE's comments as "far afield from the obligations of the companies as regulated public utilities" and "in direct contradiction to the requirements of the IRP and the longstanding policies of the Commission." More specifically, they defended their DSM screening process and the number of options considered. Relative to specific DOE recommendations, they argued that recommendations to establish a non-regulated architectural/design firm and to launch a Kentucky design initiative are beyond the scope of the IRP process. Relative to other DOE recommendations to use Local Integrated Resource Planning, to promote cogeneration or distributed generation, and to support statewide and regional market transformation initiatives, the Companies indicated their willingness to evaluate these alternatives as part of their ongoing processes. However, they pointed out that their low retail rates make it difficult to justify cogeneration or distributed generation at this time

The Office of the Attorney General (AG) also provided comments relative to the Companies' DSM efforts. According to the AG, the Companies should be commended for pursuing the cost effective DSM that was included in the IRP, but the AG also stated that "there is potential additional cost effective DSM which was screened out of consideration by the extremely subjective screening process used." The AG pointed out that 29 technologies barely missed receiving a ratings score of 3 or better in the Companies' evaluation process, with ratings between 2.7 and 2.9, and that a slight change in the subjective ratings or the threshold would have allowed them to qualify for a full evaluation. The AG therefore recommended that the Companies should allow many more DSM technologies to receive a complete analysis to determine their cost effectiveness, especially those DSM options that will reduce carbon dioxide emissions.

In the Companies' reply comments, they acknowledged that their qualitative screening process is subjective, but called it a "necessary step to reduce the number of alternatives down to a manageable level." They also noted that they are proposing the largest set of DSM programs ever in Kentucky.

Discussion of Reasonableness

In its March 1999 Staff Report on KU's 1996 IRP, Staff made the following recommendations relative to DSM for KU's consideration in preparing its next IRP filing:

- KU should not conduct judgmental screening after the detailed cost-effectiveness screening.
- KU should clarify its DSM objectives and specify DSM screening criteria at every stage that are consistent with meeting its objectives.

- At each stage of DSM screening KU should specifically outline how the established criteria were used to eliminate or pass each DSM alternative.
- KU should continue to develop DSM assumptions that are specific to its service territory.
- KU should consider fully incorporating DSM resource options into its expansion plan in a truly integrated analysis where the planning model can choose between individual supply and demand options.
- KU should report on the findings of DSM research, particularly related to commercial and industrial applications which showed the greatest potential for cost-effectiveness according to the Total Resource Cost test.
- KU should report on any changes to its DSM activities based on the results of the DSM screening using its new avoided costs.
- KU should provide a detailed discussion of how its DSM objectives, analysis and planning have been impacted due to the merger between LG&E and KU.

In commenting upon LG&E's most recent IRP in its Staff Report of March 1995, Staff made the following recommendations on DSM to LG&E:

- LG&E should expand the initial DSM option list, even including options that are not applicable to LG&E or that have load shape impacts that are inconsistent with LG&E's load shape objectives. Clearly inappropriate options can be screened out in the qualitative analysis, but at least there is documentation that LG&E considered the options.
- LG&E should reconsider the criteria used in the qualitative screen. Specifically LG&E should eliminate the criteria of "effect on summer peak," "implementation cost," "cost recovery required," "need for incentives/rebates," and "technological and administrative obstacles." Instead, LG&E may wish to consider "inconsistent with load shape objectives," "insufficient eligible market," "poor customer acceptance," "highly negative utility experience," and "immature/unavailable technology" as reasons for eliminating options in this initial screen. For each rejection, LG&E should document the source(s) of the information on which the assessment was based.
- In its next IRP filing, LG&E should provide concise and organized data sheets for each DSM program screened in the quantitative analysis.

Staff is satisfied that the Companies have adequately addressed these recommendations.

In this IRP, Staff is encouraged by the Companies' efforts to pursue DSM. However, given the nature of the subjective screening process, in the next IRP the Companies should conduct a detailed quantitative evaluation of a much larger group of DSM technologies, including technologies that fail to pass the subjective screening process.

<u>Recommendations</u>

Relative to the DSM efforts of the Companies as reflected in the 1999 IRP, Staff makes the following recommendations:

- In their next IRP filing, the Companies should reasonably expand the number of DSM technologies which receive a complete evaluation to determine if they would be cost effective.
- In their next IRP filing, the Companies should report on their efforts to evaluate and support Local Integrated Resource Planning, cogeneration and distributed generation, and statewide and regional market transformation initiatives of the type advocated by DOE.

Section 4

SUPPLY-SIDE RESOURCE ASSESSMENT

Introduction

This section summarizes and reviews the Companies' evaluation of supply-side resources, including discussion of their acid rain compliance planning.

Existing Capacity

The Companies had a total of 16 generating stations in 1999. The majority of this capacity, 21 units at 8 of these stations, was coal-fired steam generation; another 6 of these stations had combustion turbines (CTs); and there were small hydroelectric plants at Dix Dam, Lock 7, and Ohio Falls. The newest of these units were two jointly owned CTs at KU's Brown site which were placed into service in August of 1999. The 1999 summer net capacity for the Companies was 6,459 MW, while the winter net capacity was 6,696 MW. In addition, the Companies had purchase agreements in place with Electric Energy Incorporated (EEI) and Owensboro Municipal Utilities (OMU).

Reliability Criteria

The Companies' optimal resource plan study indicated that a 12% target reserve margin represents the greatest system reliability under the base assumptions. That study further indicated that an optimal target reserve margin in the range of 11-14% would provide an adequate and reliable system to meet customers' demand. In the development of the optimal integrated resource plan, the Companies used a reserve margin target of 12% to represent a base case scenario.

Supply-Side Evaluation

According to the Companies' 1999 IRP, a principal criterion in its development was to maintain flexibility. Specifically, the Companies do not plan to commit to a large block of any resource, either supply or demand-side, and be unable to adjust the plan to match changing conditions. As a part of this process, the Companies continually analyze purchase power opportunities through an RFP process and through participation in the wholesale market on a real time basis. Based upon responses to an RFP issued in February 1999, the Companies have been engaged in ongoing discussions with CT vendors and other companies on available options to meet peaking requirements beginning in the summer of 2000 and beyond.

Various supply-side options were evaluated as a part of the IRP process. An EPRI software package, TAG Supply for Windows Version 3.08, was utilized to perform the detailed screening analysis. TAG provides data and methods for determining the relative cost and performance of current/advanced electric generation and storage technologies. Adjustments were made to each technology within TAG Supply to insure the most accurate cost and performance estimates for each technology.

Alternatives were screened through a levelized screening analysis. In such an analysis, total costs are calculated for each alternative, at various levels of utilization, over a 30-year period and levelized to reflect uniform payment streams in each year. The levelized costs of each alternative at varying capacity factors are then compared and the least-cost technologies for each capacity factor increment throughout the planning period are developed.

Because the quantification of uncertainties should be an explicit part of developing cost estimates, a sensitivity analysis was included in the screening process. The screening analysis considered capital cost, heat rate, and fuel cost. Two cases were analyzed in the screening analysis to evaluate the impact of environmental legislation. Each case included the cost of mitigating NOx emissions through technology included in the capital cost of the alternative evaluated in TAG Supply. The first case includes the impact that the emission of sulfur dioxide can have on the selection of technologies. The second case, which also includes the cost of sulfur dioxide emissions, evaluates the potential additional cost of carbon dioxide emissions. One proposed solution to restrict these emissions is a carbon tax, which could substantially impact the least-cost option resulting from the screening analysis.

The sensitivity analysis required that 27 total combinations of sensitivity cases be evaluated. Because a separate analysis was performed using a carbon dioxide cost adder, that analysis produced an additional 27 combination of cases to be evaluated.

Based on the results of the levelized screening analysis, the following technologies were recommended for further evaluation in integrated resource optimization analysis:

- Combined Cycle Combustion Turbine Phased – 470 MW
- Combined Cycle CT un-Phased – 345 MW
- CT at Brown – 160 MW
- Greenfield Site CT – 160 MW
- Inlet Air Cooling at existing Brown CTs
- IPP Hydro purchase
- Pulverized Coal unit at Trimble County – 495 MW

<u>Compliance Planning</u>

The 1999 IRP included an analysis of environmental compliance options for the Companies to comply with the Clean Air Act Amendments of 1990 (CAAA). In 1995, KU complied with Phase I of the CAAA by installing a scrubber at its Ghent Unit 1. LG&E's units were fully scrubbed and were therefore not Phase I affected units. This section summarizes the Companies' plans and efforts to comply with the more stringent requirements of Phase 2 of the CAAA.

The first step in the compliance analysis was to reevaluate all possible compliance options for each generating unit through a cost screening process, using current information. Options that passed the screening process were then combined into compliance strategies and evaluated in detail in the hourly production costing model PROSYM and a capital cost evaluation using the Capital Expenditure and Recovery (CER) module of PROSCREEN II. Individual compliance options must be combined into alternative compliance plans, as the individual unit-specific options are insufficient in themselves to bring the Companies into compliance with Phase 2 sulfur dioxide emissions limits. The following combinations of compliance options were considered as appropriate for additional analysis by modeling the Companies' production costs through the 15-year planning horizon and deriving a present value of revenue requirements scenario:

- Overscrub all scrubbed units (except Green River Units 1 and 2), buy allowances.
- Overscrub all scrubbed units (except Green River Units 1 and 2), Scrub Ghent Unit 2, buy allowances.
- Overscrub all scrubbed units (except Green River 1 and 2), Scrub Ghent Unit 2, Scrub Ghent Units 3 and 4, buy allowances.
- Scrub Ghent Unit 2 only, buy allowances.
- Scrub Ghent Units 3 and 4 only, buy allowances.
- Buy allowances.

Seven alternative compliance plans were developed and evaluated. In addition, selected sensitivity studies were evaluated for the most economical compliance plans.

The results of the analysis showed that overscrubbing of all scrubbed units (Ghent Unit 1, Trimble County, Mill Creek Units 1, 2, 3 and 4, Cane Run Units 4, 5 and 6) was economically favorable as part of an overall compliance plan. Overscrubbing significantly reduces emissions and is more economical than purchasing allowances. In addition, it allows flexibility if the price for allowances changes or if the estimated cost of overscrubbing changes because the increased scrubbing levels can be adjusted without any stranded capital investment. Therefore, according to the 1999 IRP, the Companies' current compliance plan consists of overscrubbing all existing scrubbed units beginning in 2000 and retrofitting a scrubber on Ghent Units 2 and fuel switching to high sulfur coal in 2003. Throughout 2000 the Companies intend to continue to evaluate the optimal scrubbing level of the existing scrubbed units to maximize the benefits to ratepayers and shareholders.

Discussion of Reasonableness

In its 1999 Staff Report on KU's 1996 IRP, Staff made no specific recommendations relative to KU's supply-side resource assessment. However, in commenting upon LG&E's most recent IRP in its Staff Report of March 1995, Staff made the following recommendations to LG&E relative to its supply side resource assessment:

- Include key supporting data and calculations in the filing, rather than in workpapers.
- Expand the scope of "plant costs" to include land, inventory, and associated costs.
- Where appropriate, supplement TAG data with more local and current information.
- Expand the analysis of the Ohio Falls rehabilitation to screen discrete options that might be cost-effective if implemented separately.

With the exception of the analysis of the Ohio Falls rehabilitation, Staff is satisfied that the Companies have addressed these recommendations. Relative to the Ohio Falls rehabilitation, the Companies have indicated that a detailed evaluation was being done but was not yet available for inclusion into the 1999 IRP. This subject is addressed in more detail in the final section of this report.

Relative to the 1999 IRP, Staff notes in the final section of this report that the AG has criticized the Companies' screening process relative to renewable resources, and its analysis of environmental matters. These issues are discussed in greater detail in that section.

Section 5

INTEGRATION AND PLAN OPTIMIZATION

Introduction

The final step in the IRP process is the integration of supply-side and demand-side options to arrive at the optimal integrated resource plan. This section will discuss the integration process and the resulting plan, as well as recent events since the filing of the IRP in November 1999.

The Integration Process

The Companies developed the ultimate resource assessment and acquisition plan on a combined basis, assuming that the individual KU and LG&E systems constitute an integrated electric system, to produce a joint resource plan. According to the Companies' 1999 IRP, it combines the best aspects of each individual company's pre-merger resource planning process into a single integrated resource planning analysis that is well suited for the Companies' needs on a joint basis.

The optimal integrated resource planning analysis is performed using the PROSCREEN II program, which both companies used in their last IRPs. However, the optimization in the 1999 IRP explicitly included DSM alternatives; in KU's 1996 IRP, DSM options were implicitly evaluated in the optimization. The first step in PROSCREEN II optimizations was to separate the supply-side optimizations from the demand-side optimization runs, and run the supply-side optimizations. Then, because DSM projects tend to be small in nature and would only delay rather than change the supply-side expansion strategy, another set of optimizations was performed in which DSM projects were allowed to compete against the options selected during the supply-side optimizations.

Next, a review of those options which passed the supply-side screening analysis was done to determine if any technologies could be logically eliminated from the supply-side computer optimizations. This resulted in the exclusion of one technology, inlet air cooling at the Brown CTs (although the Companies expected this technology to be implemented by the summer of 2000), from the optimization runs. Next, any constraints that would limit the evaluation of unreasonable combinations of units in Proview optimizations were imposed. (Proview, or PRV, is an optimization module that evaluates all combinations of potential options to produce a list of resource plans that satisfy minimum target reserve criterion). For instance, one constraint in relation to new generating unit options is the earliest possible in-service date for each unit considered.

As well, the Companies IRP stated that there was a very high probability that no single cycle CTs will be available for in-service by 2001. Nonetheless, by allowing PROSCREEN II to install CTs as early as 2001, it clearly demonstrated the Companies' need for peaking capacity as soon as possible.

The Companies' report on its integrated analysis pointed out that no purchase power options other than the IPP hydro purchase option were passed from the supply-side screening analysis to PROSCREEN II. The wholesale purchase power market has very little if any excess generation, and peaking purchase opportunities of the type historically available do not exist. Instead, it has been replaced by a highly volatile electricity trading marketplace, which the Companies say is making the traditional RFP for purchase power process impractical today. Although the Companies continue to pursue possible opportunities through the RFP process and through participation in the wholesale marketplace, peaking type purchase power opportunities in optimizations would serve only to evaluate the delay of CT construction for short periods of time, which the Companies say they are already considering in greater detail. Regardless, the Companies intend to continue to evaluate the benefits of purchase power through real-time participation in the wholesale marketplace as a method to defer future generation construction.

With the above-mentioned and other constraints in place, the supply-side optimizations were then performed. PRV analyzes all possible combinations of alternatives using one module to determine capital costs and another module to determine operation costs. PRV then rank orders the expansion plans by their Present Value of Revenue Requirements (PVRR). An optimization was performed for each of nine different scenarios.

The next step was to let the DSM options compete with the supply-side plans, and letting PROSCREEN II determine if it is economical to use any of the DSM options to delay the supply-side expansion plan. For each of the nine different scenarios, optimizations with DSM were performed. The result was a set of optimal resource plans the Companies should follow given the occurrence of the nine possible scenarios, or future outcomes. The Companies' integrated analysis recommended Scenario 5, which included a base load and base fuel forecast. The Companies intend to re-evaluate this strategy and modify it as necessary

Description of Results

The optimal integrated resource plan recommends the implementation of all phases of each of the three DSM programs except one phase of the Standby Generation Program; the completion of the Brown CT site with an additional 160 MW CT; the development of a greenfield CT site with three 160 MW CTs in service by 2002 (and a total of ten 160 MW CTs in service by 2010); and the installation of phased constructed combined cycle CTs beginning in 2011. The projected effects of the DSM programs range from 22.1 MW from the Direct Load Control program in 2001 (and 2005) to a total of 65.9 MW from all three DSM programs in 2003.

For the short term, summer contracts were in place for 1999 to purchase 474 MW of peaking power in July and 200 MW in August, in addition to the August 1999 commissioning of the Brown units totaling 328 MW. Additional capacity was to be required, most likely in the form of purchased power, to reliably meet customer demands for the summer of 2000. In addition, the Companies were pursuing the option of Inlet Air Cooling at the Brown CTs, which was expected to add roughly 80 MW of additional peaking capacity.

Recent Events

On June 9, 2000, the Companies filed an application with the PSC for a Certificate of Public Convenience and Necessity (Case No. 2000-294) proposing to acquire two combustion turbines from LG&E Capital Corp.. One of the CTs with 133 MW of capacity is to be located at KU's Brown site, while the other with 151 MW of capacity is to be located at LG&E's Paddys Run site. At the time of this report, the PSC had not yet approved the application, although the Companies were working to achieve an in-service date of June 1, 2001 for both units.

Intervenor Comments

DOE noted its disagreement with the Companies about the purpose of integrated resource planning; more specifically, whether the Total Resource Cost test or the minimization of the utility's present value of revenue requirements should be the primary criterion for integrated resource planning. However, Staff disagrees with DOE's expansive view of the applicability of the TRC test as well as its contention that minimization of PVRR should not be the primary consideration in the development of a utility's IRP. The TRC test is a measure of expenditures for a DSM program, as both DOE and the Companies acknowledge. Minimizing PVRR has been accepted as the primary criterion for IRPs since the promulgation of 807 KAR 5:058, the regulation which requires the filing of IRPs by Kentucky's major electric utilities. Minimizing utility revenue requirements which would be borne by the utility's customers is entirely consistent with the language of KAR 5:058, which says that utility resource plans are to "meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers..." The Staff agrees with the Companies' approach which is based on minimization of PVRR.

The AG provided several comments relative to the results of the Companies' IRP process. In general terms, the AG stated that the Companies' capacity expansion plan will meet customers' future demands, but that there may be lower cost ways of meeting these needs that they "failed to consider or ... rejected due to problems with the models used." More specifically, the AG suggested that the Companies should begin to explore the possibility of acquiring additional capacity from the Ohio Valley Electric Corporation (OVEC). The Companies currently own a 9.5% interest in OVEC capacity, and the potential closure of the Portsmouth (Ohio) Gaseous Diffusion Plant would free up additional capacity. (Note: Subsequent to the filing of the AG's comments, it was announced that the Portsmouth facility would in fact be closed, although political pressure is being exerted to try to keep it operating.) The AG suggests that the Companies could use this capacity to replace one proposed CT and part of a second CT.

The AG also criticized the Companies' IRP relative to environmental matters, contending that the analysis of pending environmental matters such as Global Climate Change was inadequate. Specifically, the AG criticized the fact that "no environmental costs beyond current regulations were included in the final IRP planning," and argued that failure to include those issues in planning might exacerbate rather than correct environmental problems. For example, the AG cited the Kyoto Protocol, which calls for a 7% reduction in carbon dioxide below 1990 levels by 2010, and argued that the Companies' failure to achieve reductions could result in significant penalty taxes. For this reason, the AG recommended, at a minimum, that the Companies should run an additional optimal scenario with a carbon tax and weigh this scenario with the regular scenario to determine the additional cost of pursuing non-polluting capacity additions.

The AG also suggested that the Companies' screening process is biased against renewable resources. Because most renewable resources have no fuel cost, a graph of these resources is flat, containing just the capital cost and fixed O&M cost which are the same at all capacity factors. Once these resources are up and running, they can be run full out continuously, regardless of the capacity needs of the utility. Any excess power generated can be sold on the wholesale market, and the funds generated by those sales can be attributed to the reduction of the initial capital costs of the renewable resources. During certain periods, the utility could save money by running a hydro plant instead of burning fuel at a fossil-fuel plant, and the AG suggests that the savings, including savings of sulfur dioxide allowances, should be credited to the cost of the hydro plant. Therefore, the AG suggests that corrections should be made to the Companies' model to more accurately represent renewable resources. The DOE shared the AG's concern on this issue.

Relative to hydro resources, the AG suggested that the IPP Hydro option is the lowest cost option for the Companies at all capacity factors between 0% and 60%, and that its exclusion clearly indicates an error in the optimization model. The AG also suggested that the Companies could gain 16 MW of clean energy by rehabilitating the Falls of the Ohio hydro plant, which was built in 1928. Finally, the AG concluded by suggesting that future IRPs should do a more comprehensive job of correctly modeling and including renewable resources.

<u>Companies' Responses to Intervenors' Concerns</u>

In general terms, the Companies responded to the AG's concerns by suggesting that the 1999 IRP "includes contingent events in forecasting and planning, but only when a reasonable bandwidth of certain possibilities and factual data can be reasonably established." The Companies added that they will continue to recognize uncertainties as part of the ongoing planning process, such that all options are evaluated without bias in favor of one option over others.

More specifically, the Companies indicated that recent announcements such as the Portsmouth Plant's closure are "monitored and evaluated as a resource to meet the future needs of the native load customers as part of the ongoing process." Relative to environmental matters including the Kyoto Protocol, the Companies similarly suggested that they monitor the impact of potential environmental programs and adjust plans accordingly. They noted that they evaluated a possible carbon tax as part of the supply-side screening study, but found that it had little impact on the selection of alternatives.

With regards to the AG's criticism of the Companies' modeling of renewable resources (including hydro power), the Companies countered that the AG's criticisms are invalid. The Companies noted that their IRP is developed based upon the needs of the native load customers only and not on the ability to make sales in the wholesale marketplace. They also noted that any resource added to the supply mix that generates excess power can be sold in the wholesale market. They also argued that the AG's graphical depiction showing a modeling bias against renewable resources contains several fallacies. Furthermore, they stated that including the IPP Hydro facility as part of the future resource mix resulted in a higher cost than the plan selected in the Companies' IRP. Therefore, they argued that the AG's criticisms of the optimization model are without merit. However, Staff believes that the Companies should more fully evaluate the AG's contentions relative to the optimization model, and report on the results of this evaluation in the next IRP filing.

Finally, the Companies indicated that a study of the Ohio Falls Plant's rehabilitation is ongoing, and therefore it was not available at the time of the 1999 IRP filing. They agreed to consider this resource in future evaluations.

Discussion of Reasonableness

In its March 1999 Staff Report on KU's 1996 IRP, Staff made the following recommendations relative to the integrated process for KU's consideration in preparing its next IRP filing:

- To the extent that demand-side resources are reflected in its resource optimizations, KU should strive to fully integrate such resources into its analysis and identify the assumptions used at each step of the development of the optimal expansion plan.
- KU should report on the results of its further analysis of its Clean Air Act compliance plan, particularly with respect to the option of installing a scrubber at Ghent Unit 2 and the timing of such installation
- In consideration of changes brought about as a result of the merger of KU and LG&E, KU should discuss any changes or re-evaluations of its planning reserve margin for use in future integrated resource plans.

In commenting upon LG&E's most recent IRP in its Staff Report of March 1995, Staff made the following recommendations relative to the integrated process:

- Is the current end-year-mix-optimization step a reliable screening method? Is LG&E relying on this step to capture end-effects? Does it accurately capture these effects?
- Unexpectedly low or high gas and oil prices could conceivably affect the selection and timing of resources.

- Complete re-optimization of the resource plan under alternative future scenarios may not be the most meaningful approach. LG&E should consider revising the methodology to focus on assessing the risk-weighted costs associated with several possible next steps the utility could take.

Staff is satisfied that the Companies have adequately addressed those recommendations, and is pleased with the Companies' overall approach to the integration process. There are, however, some specific areas we believe should be addressed in the Companies' next IRP, as discussed below.

Recommendations

Relative to the Companies' 1999 IRP and the integration process, Staff makes the following recommendations:

- In the next IRP filing, the Companies should discuss in significant detail their efforts to obtain OVEC capacity related to the planned closing of the Portsmouth Gaseous Diffusion Plant.
- The next IRP filing should adequately reflect the results of the Companies' Ohio Falls hydro plant rehabilitation study.
- The Companies should fully evaluate the AG's contentions relative to potential biases in the optimization model, and report on the results of that evaluation in the next IRP filing.
- In the next IRP, the Companies should expand discussion of environmental issues to include current plans for compliance with NOx emissions requirements.

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February 16, 2000

Douglas M. Brooks, Esq.
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Louisville Gas and Electric Company
220 West Main Street
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RE: Petition for Confidential Protection
99-430

Dear Mr. Brooks:

The Commission has received your petition filed November 22, 1999, to protect as confidential the data in support of companies' 1999 Joint Integrated Resource Plan A review of the information has determined that it is entitled to the protection requested on the grounds relied upon in the petition, and it will be withheld from public inspection.

If the information becomes publicly available or no longer warrants confidential treatment, you are required by 807 KAR 5:001, Section 7(9)(a) to inform the Commission so that the information may be placed in the public record.

Sincerely,

Martin J. Huelsmann
Executive Director

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CERTIFICATE OF SERVICE

RE: Case No. 99-430
Louisville Gas and Electric Company and Kentucky Utilities Company

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed copy of the Commission Staff's data request in the above case was served upon the following by U.S. Mail on January 25, 2000.

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Stephanie J. Bell
Secretary of the Commission

Enclosure

EDUCATION PAYS

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January 25, 2000

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LG&E Energy Corp.
220 West Main Street
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RE: Case No. 99-430
Louisville Gas and Electric Company and Kentucky Utilities Company

Enclosed is one copy of the Commission Staff's data request in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

Enclosure

COMMONWEALTH OF KENTCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW PURSUANT TO 807 KAR 5:058 OF THE JOINT 1999 INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 99-430

COMMISSION STAFF'S REQUEST FOR INFORMATION TO LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

The Commission Staff requests that Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") file an original and 6 copies of the following information, with a copy to all parties of record, by no later than February 23, 2000. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 5. Include with each response the name of the person responsible for responding to questions relating to the information provided.

1. Please provide the following annual (redacted) information for the 15-year forecast period.

a. The assumed average real price of electricity for LG&E.

b. The assumed average percentage increase in the nominal retail price of electricity for KU.

c. The assumed average nominal percentage increase in the residential price of gas over the next five years and over the next 15 years.

2. Given the situation in the market for CTs, what specific plans have been made to ensure that LG&E and KU have capacity additions of 480 MW in 2001, an additional 160 MW in 2002, and an additional 160 MW in 2004?

3. For LG&E, Technical Appendix I, Volume II:

a) In Table C5 on page C-17, why does the Total Sales column have KWH Sales as the title when the title of this Table says "MWH"? Are sales in KWH or MWH?

b) Why does (Year – 1998) enter linearly only in the Residential equation? (In other class' equations, it enters exponentially).

c) Why does (Trend94) enter logarithmically in Small Commercial/Industrial and Large Commercial, Weather-Sensitive Energy Sales equations?

d) Where are the energy price variables in each of the short – term forecasting equations?

e) Why do ACSAT and RSCUST enter the Long-term Air Conditioning equation in double-log form (ln(ln)) on pages 24 and 28)?

f) How were the equations included herein estimated (Ordinary Least Squares, Generalized Least Squares, Other)?

4. How do the assumptions for the Optimistic and Pessimistic outlook differ from those of the Baseline Forecast?

5. For KU, Volume II:

a) In KU-7 on page 17, the Kentucky retail price forecasts are displayed both for the 1999 IRP and that from 1996.

i. Why are prices expected to dramatically increase from 2000 to 2003 and then fall precipitously in 2004?

ii. Why are the prices forecasted for the 1999 IRP so far below those that were forecasted in the 1996 IRP?

b) Why are the RS and FERS rate classes treated differently in the REEPS model (see, for example, page 20, 2nd full paragraph)?

c) In the short-run RS Monthly KWH on page 34:

(i) Where are the t-statistics that correspond to the estimated parameters of this equation?

(ii) What comprises the variable $RSPRICE_{-1}$? In other words, does it include the adjustments to base rates (FAC, Merger Surcredit, etc.) or just base rates themselves? By how much does RSPRICE vary from month to month?

(iii) How was the equation estimated (Ordinary Least Squares, General Least Squares, other)?

d. In FERS short-run equation for Monthly kWH, provide a better explain as to the reason that July, February, and March are included as binary variables.

e. In the COMCUST equation on page 48, why are commercial customers forecast as a function of residential customers?

f. In the HEATING Season: KWH per customer equation on page 50:

(i) Where is the Real Average Commercial price variable and what is its estimated coefficient?

(ii) What is the estimate of rho (ρ), the coefficient of AR1? Why is it included in the Cooling Season equation, but not in the Heating Season?

(iii) How was this equation estimated (Generalized Least Squares, Cochran – Orcutt, Other)?

g. Why are the first differences of the variables used to estimate the industrial KWH equations?

6. Refer to page 5-21 of the IRP, specifically the last sentence that indicates the difference between KU's summer and winter peaks is expected to narrow over the forecast period. Identify the factors and/or reasons to which KU attributes this narrowing between its summer and winter peaks.

7. Refer to page 5-35 of the IRP that references the Request for Proposal ("RFP") issued in September 1999 to the three major Combustion Turbine ("CT") manufacturers. Regarding this RFP, provide the following information.

a. The actual RFP issued to ABB, GE, and Seimens Westinghouse.

b. If already received, the responses from each of the three manufacturers.

c. Identify any 'minor' CT manufacturers that were not issued the RFP and explain the reasons for not seeking proposals from them.

8. Refer to page 6-4 of the IRP that discusses the changes in the population forecasts for LG&E's service territory from its 1993 IRP filing to the 1999 IRP.

a. Was the University of Kentucky's Center for Business and Economic Research the source used for population forecasting in LG&E's 1993 IRP?

b. If no, identify the entity that was the source of the previous population forecast, and explain why LG&E chose to make a change for this IRP.

9. Refer to page 6-5 of the IRP which refers to the six-year difference in the 20-year "average weather" study (1979-1998) reflected in the current IRP compared to the comparable study reflected in the 1993 IRP (1973-1992). Provide, in summary form, the results of those studies, and a description of the impact of the new study on the 1999 energy and demand forecasts included in the current IRP.

10. Refer to page 6-11 of the IRP. Explain the reasons for the use of separate models for wholesale sales to the cities of Pitcairn, Pennsylvania and Paris, Kentucky compared to KU's other wholesale customers.

11. Refer to page 6-16 of the IRP regarding the renovation of the Ohio Falls generating station. Identify and describe any developments regarding this project since the time the IRP was prepared.

12. Refer to page 7-12 of the IRP which states that WEFA's 20-year long-term forecasts released in the first quarter of 1993 were utilized as inputs for national economic and demographic variables. Explain whether the reference to "1993" is correct, and if so, explain why more current forecasts were not utilized for the inputs previously described.

13. Refer to page 7-23, specifically Table 7(7)(d)-2, of the IRP. In general, identify and describe the factors that account for the difference between the Optimistic and Base forecasts being consistently greater than the difference between the Base and Pessimistic forecasts.

14. Refer to page 7-52 of the IRP, specifically the reference to "cooling degree-days using a 70-degree base." Many utilities use a 65-degree base for calculating cooling-degree days. Indicate when KU began using a 70-degree base in determining cooling degree-days, and whether this was the result of an in-house study or was based on an industry analysis performed by an outside source.

15. Refer to page 7-60 of the IRP. Provide a more detailed discussion of how the probabilities identified in the table were derived, particularly focusing on the reasons for the much greater probability assigned to the Pessimistic Forecast as compared to the Optimistic Forecast. Also explain in greater detail the reasons for why the probability of the Optimistic Forecast occurring might be understated as stated in the text on that page.

16. Refer to page 8-2 of the IRP which refers to the potential installation of Inlet Air Cooling ("AIC ") at Brown Stations 8-11. Are Brown Stations 6 and 7 already equipped with AIC? If not, explain why they are not included along with Stations 8-11.

17. Refer to page 8-5 of the IRP which refers to the installation of Distributive Control Systems ("DCS") at various LG&E and KU units. Provide the status of any current plans for installing DCS at any other units not identified in the discussion on page 8-5.

18. Refer to pages 8-8 and 8-9 of the IRP which describe LG&E's installation of additional capacitors on it distribution system to provide more efficient use of substation transformer capacity and its modified guidelines that allow substation distribution transformer loading up to 120 percent of top nameplate rating, during contingency conditions.

a. Provide the source and results of the referenced studies that have shown that loading up to 120 percent of top nameplate rating for short periods of time causes no appreciable loss of life.

b. Is this limited to LG&E or is KU also doing this? If no, explain why KU is not pursuing similar distribution system efficiencies.

19. Refer to the table on page 8-75 identified as "Total Electricity Production Costs." Was 1.65 cents per Kwh representative of LG&E's and KU's generation costs in 1998 as if their rates had been unbundled? If not, identify and explain the adjustments or modifications that would be required in order to derive a representative rate for generation and show the derivation of the rate(s).

20. Provide the following information related to the existing rate programs identified on pages 8-80 and 8-81 of the IRP.

a. The number of customers on KU's CWH rate schedule.

b. The number of customers served and the MW available for curtailment under KU's CSR rate schedule.

c. The number of customers served on KU's Time-of-Day rate schedules and the estimated impact of those schedules on KU's peak demand.

d. The number of customers taking service under LG&E's Interruptible Service Rider and the MW subject to interruption.

e. The number of customers served on LG&E's Time-of-Day rate schedules and the estimated impact of those schedules on LG&E's peak demand.

21. Refer to the discussion on page 8-81 of the IRP concerning the proposed Direct Load Control program. Provide, in summary form, a description and the results

of any similar programs either LG&E or KU has implemented in the past 10 years (1990-1999).

22. Refer to the discussion on page 8-81 of the IRP regarding Standby Generation. Provide the total number of customers, on both systems, that have back-up generating facilities, and the estimated MW potential of such a program.

23. Refer to the table on page 8-85 of the IRP. Explain why the impact of interruptible rates is shown at 121 MW in 1999 and only 80 MW for subsequent years.

24. Refer to the tables on pages 8-89 and 8-90 of the IRP showing resource capacity available over the forecast period. Appendix A, Table 2, shows the in-service dates of all generating units. Given the age of some of the units, explain why the projected resource capacity available for the forecast period does not reflect any planned retirements.

25. Refer to page 8-100 of the IRP that indicates your current Clean Air Act Compliance Plan includes installation of a scrubber on Ghent 2 in 2003. If nothing changes to alter this plan, provide the approximate timetable for filing an application for a Certificate of Public Convenience and Necessity.

26. Refer to page 8-102 of the IRP describing the events of July 30, 1999. Provide a detailed description and explanation for why LG&E's "actual interruptible was 75 megawatts less than anticipated."

27. Refer to pages 8-111 and 8-112 of the IRP regarding Supply-side Screening. Provide the percentage increases in cost for TAG Supply technologies 15.1, 15.2, and 15.3 based on current bid prices for these sizes and types of CTs.

28. Refer to pages 8-125 and 8-126 of the IRP regarding NO_x emission rates.

a. Identify which existing generating units have tangentially-fired boilers and which have dry-bottom, wall-fired boilers.

b. Provide the scheduled installation dates for the advanced low NO_x burners on Ghent Units 2, 3 and 4.

29. Refer to the discussion on page 8-128 of the IRP concerning the Sargent & Lundy system-wide NO_x compliance study.

a. Provide the date the study was initiated and its expected completion date.

b. Could the results of this study potentially alter LG&E's and KU's current CAAA compliance plan? Is yes, in what ways?

30. Refer to the Technical Appendix, specifically the DSM Analysis. One of the programs that failed the benefit-to-cost analysis was the DLC water heater program for residential customers. Provide the cost estimates and other supporting data that resulted in the TRC test result of .87 for this program.

31. Refer to the Technical Appendix, specifically the CAAA Compliance Analysis. This text of this analysis would seem to suggest that the plan to install a scrubber at Ghent 2 is still being evaluated. However, the discussion on page 8-100 of the IRP and other points of reference, states that your current Clean Air Act Compliance Plan includes, among other things, installation of a scrubber at Ghent 2. Is this issue still being evaluated or has the decision been made? Explain the reasons for the

32. discrepancy in the text of the IRP and the text of the CAAA Analysis in the Technical Appendix.

Respectively submitted,

Richard G. Raff

Richard G. Raff
Staff Attorney

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	) Case No.) 99-430)

RECEIVED
JAN 2 5 2000
PUBLIC SERVICE COMMISSION

THE ATTORNEY GENERAL'S
INITIAL REQUESTS FOR INFORMATION

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office for Rate Intervention, and submits these Requests for Information to Louisville Gas and Electric Company and Kentucky Utilities Company, Inc., to be answered in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the company witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please

identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Respectfully Submitted,

Blackford

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4815

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that the original and twelve copies of the foregoing were filed this the 25th day of January, 2000, with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and certify that on this same date true copies were served on the parties by mailing same, postage prepaid to:

HONORABLE DOUGLAS BROOKS
SENIOR COUNSEL SPECIALIST
LOUSIVILLE GAS & ELECTRIC COMPANY
P O BOX 32010
LOUISVILLE KY 40232-2010

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LOUISVILLE RESOURCE

HONORABLE IRIS SKIDMORE
HONORABLE RONALD P MILLS
OFFICE OF LEGAL SERVICES
FIFTH FLOOR CAPITAL PLAZA TOWER
FRANKFORT KY 40601

/s/ Blackford

THE ATTORNEY GENERAL'S REQUESTS FOR INFORMATION

1. On page 5-23 of Volume I, the assumption is stated that the future climate will reflect the weather values of the most recent twenty-year period. Recent weather data shows that global temperatures are rising rapidly, as seen in the high temperatures in the last decade. Please explain why the past twenty years is a good assumption for future temperatures.

2. On page 5-24 of Volume I, it is stated that the appliance efficiency standards from the 1992 National Energy Policy Act were included in the KU forecast:

a) Please provide a detailed explanation of exactly how these appliance standards were incorporated in the forecast.

b) Were these standards included in LG&E's forecast? If so, please explain how. If not, please explain why not.

3. On page 5-32 of Volume I, it is stated that an Inlet Air Cooling system is being added to Brown units 8-11. Please state why a similar system is not being added to Brown units 6 and 7, since they are to be dispatched more often, according to Table

8.(3)(b)12.

4. On page 5-35 of Volume I, a September 27, 1999, IRP for combustion turbines is described. Without revealing any confidential information, please provide the results of this IRP, and whether any bids were found to be acceptable and will be exercised.

5. On page 6-15 of Volume I, an Ohio Falls evaluation is mentioned. Please provide the results of that evaluation.

6. On page 5-33 of Volume I, Table 7.(2)(h)-2 presents historic electric appliance saturations for KU. Please provide a similar historic saturation summary for LG&E.

7. On page 8-81 of Volume I, future DSM programs are discussed.

a) Have these programs been presented to and approved by the LG&E DSM Collaborative? If not, do you intend to get approval for the programs from the Collaborative?

b) Please provide the avoided costs, based on the current IRP, that are used to calculate the benefit of DSM programs. Please also provide the calculations, assumptions and workpapers used to develop these rates.

c) Please provide the avoided costs, based on the current IRP, that are offered to Qualifying Facilities. If they are different than those used in the DSM analysis, please explain why they are different.

8. In Volume I , on page 8-101 of the IRP, reference is made to LG&E/KU companies' participation in the Ohio Valley Electric Corporation (OVEC). With respect to that participation, please supply the following:

a) Percent of participation and associated number of Megawatts for KU and for LG&E.

b) Number of Kilowatt-hours sold to OVEC by LG&E/KU for each of the last 5 years.

c) Number of Kilowatt-hours bought by OVEC from LG&E/KU for each of the last 5 years.

d) In December 1999, the United States Enrichment Corporation's President William Timbers stated that his company is "analyzing whether to shut down one of its two production plants", and that upgrades were being made to the Paducah plant to match the capabilities of the Piketon plant (the Courier-Journal, "Uranium operator could shut down 1 of its 2 plants", December 12, 1999). Has LG&E/KU included in the IRP the very real possibility that the Piketon plant may be shut down in the near future and that LG&E/KU's OVEC capacity may become available for LG&E/KU's use?

9. On page 8-106 of Volume I, the IRP outlines a number of proposals to reduce carbon dioxide emissions. Please explain in detail how this IRP prepares KU and LG&E for future mandated reductions in carbon dioxide emissions that are likely.

10. On page 8-106 of Volume I, the IRP outlines a proposal to establish an "energy portfolio standard" requiring minimum use of renewable resources:

a) What is LG&E's current reliance on renewable resources?

b) What is KU's current reliance on renewable resources?

c) Please explain in detail how this IRP is preparing LG&E/KU for a possible future requirement of minimum use of renewable resources?

11. On page 8-120 of Volume I, the limitation of only one IPP Hydro purchase is mentioned. Please explain why this constraint is included, considering the large number of dams on the Ohio river that have yet to have hydro added to them.

12. On page A-5 and A-6 of Volume II, historic peak load data is provided through 1998. Please provide this same information for each table for the year 1999.

13. On page B-3 of Volume II, projected air conditioning saturation exceeds 99% in 2013.

a) The projected saturation of air conditioners is much higher than penetration of telephones, which are considered a necessity. Please provide evidence that this high saturation is possible.

b) If air conditioning saturation approaches 99%, should it be classified as a necessity rather than as a luxury in this region of the country?

14. In Volume II, Appendix 2, page 23, projections for the all-electric ERS class is given. Please provide a projection of a breakdown of these customers into resistance heat customers, air source heat pump customers, and ground source heat pump customers.

15. In Volume III, Section III, in Appendix A - Table 2 outlines generator data. This chart shows that the Tyrone, Pineville and Green River units range in age around 50 years. In the past, KU stated an expected life of generating units of 54 years. Does KU intend to retire or repower any of the very old units in the near future? If so, please provide details. If not, please provide the expected life of these units.

16. In Volume III, Section IV, in Phase I screening, a large number of DSM programs just barely missed the 3.0 cutoff. Considering that both the assignment of ratings and the cutoff point were subjective judgements, please explain why these programs that just barely missed the cutoff weren't also given a Phase II analysis.

17. In Volume III, Section IV, page 13 states that DSM measures are less attractive since real energy costs are decreasing. Isn't it true that the avoided costs by which the benefits of DSM programs are measured have been increasing recently, as market prices for power have been increasing?

18. On page 42 of Section V of Volume III of the IRP, Carbon Dioxide impacts are analyzed. For each of the last 11 years, 1989-1999, please supply the following:

a) Total carbon dioxide emissions associated with supplying LG&E and KU's internal energy demand, including municipals.

b) Total carbon dioxide emissions associated with selling power off-system.

c) Total carbon dioxide emissions from LG&E/KU generators (thus including off-system sales but excluding emissions associated with energy purchased to supply internal energy demand).

19. On page 42 of Section V of Volume III of the IRP, Carbon Dioxide impacts are analyzed. For each of the years in the IRP planning period, through 2013, and based on the base plan in the IRP, please supply the following:

a) Total carbon dioxide emissions associated with supplying LG&E and KU's internal energy demand, including municipals.

b) Total carbon dioxide emissions associated with selling power off-system.

c) Total carbon dioxide emissions from LG&E/KU generators (thus including off-system sales but excluding emissions associated with energy purchased to supply internal energy demand).

20. In Volume I, Table 8.(4)(b) and Table 8.(4)(c) display forecast energy and fuel use by fuel type for the forecast period. Please provide the same tables with the same type of information for the past 11 years, 1989-1999

21. On page 25 of Section V of Volume III of the IRP, Nitric Dioxide (NOx) emissions are mentioned. For each of the last 11 years, 1989-1999, please supply the following:

a) Total NOx emissions associated with supplying LG&E and KU's internal energy demand, including municipals.

b) Total NOx emissions associated with selling power off-system.

c) Total NOx emissions from LG&E/KU generators (thus including off-system sales but excluding emissions associated with energy purchased to supply internal energy demand).

22. On page 25 of Section V of Volume III of the IRP, Nitric Dioxide (NOx) emissions are mentioned. For each of the years in the IRP planning period, through 2013, and based on the base plan in the IRP, please supply the following:

a) Total NOx emissions associated with supplying LG&E and KU's internal energy demand, including municipals.

b) Total NOx emissions associated with selling power off-system.

c) Total NOx emissions from LG&E/KU generators (thus including off-system sales but excluding emissions associated with energy purchased to supply internal energy demand).

23. In Volume III, Section V, Exhibits 9 and 10 show the capacity options with lowest costs at different capacity factors, and without the CO2 adders. Please provide the results of these same two exhibits with the scenario of including the CO2 adders.

24. In Volume III, Section VII, the optimal IRP analysis is

outlined. Please explain why it includes a sensitivity analysis for load and fuel prices, but fails to include the possibility of future environmental regulations such as carbon dioxide emission limitations?

25. In Volume III, Section IX, on page PSC-6, the PSC said KU should incorporate potential environmental costs into forecasts and uncertainty analysis. The response in the IRP does not address the PSC's concern. Please explain why potential environmental costs were not included in the forecasts and uncertainty analysis in the 1999 IRP.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
JAN 18 2000
PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN	**)**	
OF LOUISVILLE GAS AND ELECTRIC COMPANY	**)**	**CASE NO. 99-430**
AND KENTUCKY UTILITIES COMPANY	**)**	

KENTUCKY DIVISION OF ENERGY'S FIRST
SET OF INTERROGATORIES
TO THE LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY

Comes the Natural Resources and Environmental Protection Cabinet, Division of Energy, Intervenor herein, and makes the following request for information for the purpose of evaluating the effectiveness of the proposed joint integrated resource plan (IRP):

1. From where did the "long list" of DSM alternatives come (Volume III, Section IV, Exhibit DSM-1)?

2. Has either the Louisville Gas and Electric Company or Kentucky Utilities Company (hereinafter "the Companies") availed itself of information from organizations such as E-Source, which is a source of comprehensive information on energy efficiency technologies and programs? To what extent, if any, was information from such sources used in developing the IRP?

3. a. In developing the IRP, did the Companies perform a study to estimate the quantity of demand-side energy efficiency and load-shifting measures that would be available within the joint service area (i.e., a Technical Potential study), the cost of implementing such

measures, and the revenue requirements that would be needed to acquire various portions of these potential resources through DSM programs?

b. If so, what is the size of these potential DSM resources?

c. If a Technical Potential study was done and was not included in the submittal, please provide it.

d. If a Technical Potential study was not done, why not?

4. Did the Companies estimate the square footage of residential, commercial, and industrial floor space that is being newly constructed each year in their combined service area? If so, what are the estimated square footage figures?

5. Did the Companies survey the energy efficiency of the range of types of new buildings being constructed in their combined service area? If so, please provide the results of this analysis.

6. Please describe the following programs from Exhibit DSM-1 in more detail:

a. House Doctor – energy audit (#16)

b. Energy efficient products (#20)

c. Smart thermostats (special rate) (#28)

d. Demand subscription (#31)

e. Efficient construction, residential (#32)

f. Education (#33, 60, 81)

g. Polarized refrigerant oxidant agent (#51)

h. Interruptible rates (#58, 79)

i. Construction building standards (#61)

j. Process and energy audit (#71)

k. Variable speed motors (#73)

l. High efficiency motor and adjustable speed drives (#74)

7. "Efficient Construction" was included in the long list of residential programs (#32). In view of the emphasis placed on new commercial construction programs in the LG&E DSM Collaborative's 1996 DSM Program Plan, filed on December 1, 1995, and in the Collaborative's Joint Application, filed on February 18, 1997, why wasn't "Efficient Construction" included in the long list as a possible program for the commercial or industrial sectors?

8. Approximately what fraction of the windows being sold in the Companies' service area are "low-e?" Please document the response.

9. What is the incremental cost of "low-e" windows compared to "non-low-e" windows? Please document the response.

10. The last sentence of the paragraph after Exhibit DSM-2 (Volume III, Section IV) states, "The selected cutoff will be determined from any obvious breakpoints between the sorted weighted average scores of the measures." The decision to set the breakpoint at 3.0 caused 66 of the 82 items from the long list (i.e., 80% of the items) to be screened out. Why didn't the Companies set the breakpoint lower and thereby screen out fewer items?

11. Did the Companies consider the possibility that some of the items in the long list might not be ranked high when considered individually, but might be cost-effective if included in a package along with other complementary items? Please explain the response.

12. In Exhibit DSM-3, please explain why commercial thermal energy storage is rated 3,3,4,4 while industrial thermal energy storage is rated 2,3,3,3.

13. Isn't it true that customer cost is a function of the design of a DSM program? In other words, if the utility pays 80% of the cost of installing a demand-side technology, wouldn't the customer cost be lower than if the utility pays only 10% of the cost?

14. Exhibit DSM-2 defines "Customer Acceptance" to mean, "Are there an acceptable number of customers willing to participate to create a successful program?" What was the number of customers that was considered necessary for a program to earn a rating of 1, 2, 3, or 4, respectively? If the interdepartmental DSM team did not actually think in terms of the number of customers, please provide a more accurate and complete definition for the criterion "Customer Acceptance."

15. Isn't it true that customer acceptance is a function of the design of a DSM program? In other words, if the utility pays a residential customer $100 a year to sign an interruptible service agreement, for example, wouldn't he or she be more likely to accept it than if the utility pays only $10 a year for the same agreement?

16. Please explain, providing as much detail as possible, why the criteria of "Maturity of Technology" and "Data Confidence" are combined.

17. Please explain, providing as much detail as possible, precisely what is meant by the criterion "Maturity of Technology (Is the technology commercially available?)".

18. Please explain, providing as much detail as possible, precisely what is meant by the criterion "Data Confidence (Is the necessary data available to evaluate this measure?)".

19. Consider two hypothetical DSM programs that are identical in all respects (including total implementation costs) except for the following projected impacts: Company analysts are 95% confident that Program A will reduce demand uniformly throughout the year by an amount somewhere between 500 kW and 1,500 kW; while the analysts are 95% confident that

Program B will reduce demand uniformly throughout the year by an amount somewhere between 399.99 kW and 400.01 kW. Which program should receive a higher priority for implementation? Please explain the response.

20. Consider the following three hypothetical commercial DSM programs:

a. Program A reduces demand by 1 kW uniformly throughout the year.
b. Program B reduces demand by 5kW on weekday afternoons from 1:00 pm to 6:00 pm during the months of May through September inclusive (i.e., a peak-shaving program with zero impact at other times).
c. Program C reduces demand by 6kW from 1:00 pm to 6:00 pm, and increases demand by 3kW from midnight to 5:00 am on weekdays during the months of May through September inclusive (i.e., some energy use is shifted from on-peak to off-peak hours; zero impact at other times).

Each program costs $1,000 to implement (including all program costs), 90% of which is paid by the utility (i.e., the cost to the participating commercial customer = $100). Assume that the measure life is 20 years and that there are no free riders. Please use DSManager to provide the present value dollar amounts of the benefits, costs, and benefit/cost ratios for each program using the following five standard "California" tests:

a. Participant
b. Utility Cost
c. RIM
d. TRC
e. Societal Cost

In the alternative, please provide the necessary information, software and methodology to allow the Division of Energy to do the calculations.

21. When deciding on the set of DSM programs to recommend for pilot-scale implementation, did the Companies consider "the extent to which the plan provides programs which are available, affordable, and useful to all customers" [Reference KRS 278.285 (1)(g)]? Please discuss the degree to which the set of recommended DSM programs meets this statutory criterion.

22. Section VIII in Volume III lists 53 transmission construction projects the Companies are planning to complete between 2000 and 2009 to maintain the adequacy of its transmission system to meet projected customer demands. The method of local integrated resource planning (LIRP), as described in the strategic issues paper titled, "Local Integrated Resource Planning: A New Tool for a Competitive Era" (E-Source, 1995) is designed to determine if costs could be reduced by deferring transmission and distribution upgrades through the use of geographically-focused demand-side programs. [Other names for LIRP include "targeted area planning," "local area investment planning," "distributed resources planning," or "area wide asset and customer service."]

a. Did the Companies use the LIRP approach to determine whether any planned transmission or distribution projects could economically be deferred? If so, please provide the results of the studies.

b. Do the Companies plan to use the LIRP approach in the future?

23. Section 8.(3)(e)(4) (Volume I, page 8-83) refers to the NPV costs of certain demand-side programs. What discount rate was used to calculate the net present value (NPV)? What was the basis for the particular discount rate used?

24. The first sentence on page 8-84 reads, "The difference between the PVRR with and without the direct load control program is $32.1 million." Does this statement mean that the Companies' present value of revenue requirements (PVRR) would be reduced by $32.1 million if the direct load control program were to be implemented as projected? If this interpretation is incorrect, please explain.

25. The first paragraph on page 8-121 states: "The plans developed utilizing PROSCREEN II, both in the supply-side optimization and the optimizations with DSM included, are rank-ordered based upon the plans PVRR. The plan with the lowest PVRR is considered the optimal integrated resource plan." Does the plan with the lowest PVRR have the minimum total resource cost (TRC)? Please explain the response.

26. Please provide a detailed description of the method the Companies use to determine how much to charge a new residential, commercial, or industrial customer to hook up their building to the grid. Please explain why this particular method or formula was chosen.

27. The section on biomass energy (Volume III, Section V) discusses only technologies that are fueled 100% by biomass. Did the Companies evaluate the cofiring of coal with sawdust at low percentages (e.g., less than 2 or 3 percent sawdust by weight) at existing coal-fired plants, which would provide a valuable service for the sawmill operations located in or near the Companies' service territory and also would reduce SO_2 emissions? Please explain the response.

28. Do the Companies intend to file proposed net metering pilot program tariffs with the PSC, which, if approved, would make net metering service available to small-scale customer-generators who produce electricity using renewables, fuel cells, or microturbines. If yes, when? If yes, do the Companies believe that net metered customer-generators will have a measurable

impact on the system load during the planning period covered by the IRP? If so, what is the estimated impact during each future year? Please explain the response. If the Companies do not intend to file proposed net metering pilot program tariffs with the PSC, why not?

29. To what extent have the Companies encouraged the installation of combined heat and power (cogeneration) systems by industrial firms in its service area? Please provide quantitative information if available.

Respectfully submitted,

IRIS SKIDMORE
RONALD P. MILLS
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601
Telephone: (502) 564-6676

COUNSEL FOR NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that on the 18th day of January 2000 a true and accurate copy of the foregoing Kentucky Division Of Energy's First Request For Information To The Louisville Gas And Electric Company And Kentucky Utilities Company was mailed, postage pre-paid, to the following:

Hon. Douglas Brooks
Senior Counsel Specialist
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220 W. Main Street
P.O. Box 32010
Louisville, Kentucky 40232-2010

Hon. Elizabeth E. Blackford
Office of Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601

Hon. David F. Boehm
Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

Mr. Walter F. Bell, Executive Director
Louisville Resource Conservation Council
P. O. Box 4174
Louisville, KY. 40204-0174

Iris Skidmore

LG&E[SM]

Law Department

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502-627-3460
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January 4, 2000

RECEIVED

JAN 05 2000

PUBLIC SERVICE
COMMISSION

Helen C. Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602-0615

RE: Case No. 99-430

Dear Ms. Helton:

Enclosed for filing in the above-referenced case are the following:

1. An Affidavit of Publication from The Courier Journal and Louisville Times Incorporated regarding the Notice of Filing in this case; and,

2. A Notarized Proof of Publication from the Kentucky Press Service regarding the Notice to Kentucky Utility Company Customers in this case.

A copy of this letter has been mailed to the parties of record as reflected on the attached service list. Please contact me if there are any questions about this filing.

Sincerely yours,

Douglas M. Brooks

Douglas M. Brooks
Senior Counsel Specialist, Regulatory
(502) 627-2557

LG&E

Service List for Case No. 99-430

Honorable Elizabeth E. Blackford
Assistant Attorney General
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1024 Capital Center Drive
Frankfort, KY 40602

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Honorable Michael L. Kurtz
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John M. Stapleton
Director, Division of Energy
663 Teton Trail
Frankfort, KY 40601

RECEIVED
JAN 05 2000
PUBLIC SERVICE COMMISSION

THE COURIER JOURNAL and LOUISVILLE TIMES
Incorporated

STATE of KENTUCKY
County of Jefferson

Affidavit of Publication

I, Judy Reece
of THE COURIER-JOURNAL AND LOUISVILLE TIMES COMPANY, publisher of The COURIER-JOURNAL, a newspaper of general circulation printed and published at Louisville, Kentucky, do solemnly swear that from my own personal knowledge, and reference to the files of said publication, the advertisement of

LEGAL 105 JOINT INTEGRATE

was inserted in THE COURIER-JOURNAL as follows:

Date	Lines	Date	Lines
12/10/1999	43		

NOTICE OF FILING

On November 22, 1999 Louisville Gas and Electric Company and Kentucky Utilities Company filed a Joint Integrated Resource Plan with the Public Service Commission (Case No. 99-430). This filing includes the Companies' most recent load forecasts and a description of the existing and planned conservation programs, load management programs and generating facilities they intend to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utilities, and file written comments on the plan.

Any person interested in participating in the review of this Joint Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to:

Helen C. Helton,
Executive Director,
Public Service
Commission,
P.O. Box 615,
Frankfort, Kentucky 40602.

LOUISVILLE GAS AND
ELECTRIC COMPANY
220 West Main Street
Louisville, Kentucky

Judy Reece

(Signature of person making proof)

Subscribed and sworn to before me this 14 day of December, 1999.

My commission expires May 25, 2002.

Jerri Allison

Jerri Allison (Notary Public)

THE COURIER JOURNAL and LOUISVILLE TIMES
Incorporated

STATE of KENTUCKY
County of Jefferson

Affidavit of Publication

I, Judy Reece
of THE COURIER-JOURNAL AND LOUISVILLE TIMES COMPANY, publisher of The COURIER-JOURNAL, a newspaper of general circulation printed and published at Louisville, Kentucky, do solemnly swear that from my own personal knowledge, and reference to the files of said publication, the advertisement of

LEGAL 105 JOINT INTEGRATE

was inserted in THE COURIER-JOURNAL as follows:

Date	Lines	Date	Lines
12/10/1999	43		

NOTICE OF FILING
On November 22, 1999 Louisville Gas and Electric Company and Kentucky Utilities Company filed a Joint Integrated Resource Plan with the Public Service Commission (Case No. 99-430). This filing includes the Companies' most recent load forecasts and a description of the existing and planned conservation programs, load management programs and generating facilities they intend to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utilities, and file written comments on the plan.
Any person interested in participating in the review of this Joint Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to:
Helen C. Helton,
Executive Director,
Public Service
Commission,
P.O. Box 615,
Frankfort, Kentucky 40602.

LOUISVILLE GAS AND ELECTRIC COMPANY
220 West Main Street
Louisville, Kentucky

Judy Reece
(Signature of person making proof)

Subscribed and sworn to before me this 14 day of December, 1999.

My commission expires May 25, 2002.

Jerri Allison
Jerri Allison (Notary Public)

THE COURIER JOURNAL and LOUISVILLE TIMES
Incorporated

STATE of KENTUCKY
County of Jefferson

Affidavit of Publication

I, Judy Reece of THE COURIER-JOURNAL AND LOUISVILLE TIMES COMPANY, publisher of The COURIER-JOURNAL, a newspaper of general circulation printed and published at Louisville, Kentucky, do solemnly swear that from my own personal knowledge, and reference to the files of said publication, the advertisement of

LEGAL 105 JOINT INTEGRATE

was inserted in THE COURIER-JOURNAL as follows:

Date	Lines	Date	Lines
12/10/1999	43		

NOTICE OF FILING

On November 22, 1999 Louisville Gas and Electric Company and Kentucky Utilities Company filed a Joint Integrated Resource Plan with the Public Service Commission (Case No. 99-430). This filing includes the Companies' most recent load forecasts and a description of the existing and planned conservation programs, load management programs and generating facilities they intend to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utilities, and file written comments on the plan.

Any person interested in participating in the review of this Joint Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to:

Helen C. Helton,
Executive Director,
Public Service Commission,
P.O. Box 615,
Frankfort, Kentucky 40602.

LOUISVILLE GAS AND ELECTRIC COMPANY
220 West Main Street
Louisville, Kentucky

Judy Reece
(Signature of person making proof)

Subscribed and sworn to before me this 14 day of December, 1999.

My commission expires May 25, 2002

Jerri Allison
Jerri Allison (Notary Public)

NOTARIZED PROOF OF PUBLICATION

STATE OF KENTUCKY

COUNTY OF Franklin

Before me, a Notary Public, in and for said County and State, this 29 day of Dec., 1999, came Rachel Mc Carty personally known to me, who being duly sworn, states as follows:

That she is Advertising Assistant of the Kentucky Press Service, Inc., and that the following publications: see attachment ran the Legal Notice for Kentucky Utilities ~~Notice~~ to Company Customers the week of December 13, 1999.

Rachel McCarty
Signed

Bonnie J. Howard
Notary Public

My commission expires 9-18-2000

KENTUCKY PRESS SERVICE

101 Consumer Lane **Frankfort, KY 40601**
(502) 223-8821 **FAX (502) 875-2624**
Gloria Davis, Ad Director

List of newspapers running the Notice to Kentucky Utilities Company Customers. Attached tearsheets provide proof of publication:

Barbourville Mountain Advocate
Bardstown Kentucky Standard
Beattyville Enterprise
Bedford Trimble Banner Democrat
Berea Citizen
Brooksville Bracken County News
Brownsville Edmonson News
Calhoun McLean County News
Campbellsville Central KY News Journal
Carlisle Mercury
Carrollton News Democrat
Cave City Barren County Progress
Central City Times Argus
Clinton Hickman County Gazette
Columbia Adair Progress
Columbia News
Corbin Times Tribune
Cumberland Tri City News
Cynthiana Democrat
Danville Advocate Messenger
Danville Lincoln Ledger
Dawson Springs Progress
Eddyville Herald Ledger
Elizabethtown Hardin Co. Independent
Elizabethtown News Enterprise
Falmouth Outlook
Flemingsburg Shopper
Frankfort State Journal
Fulton Leader
Georgetown News
Glasgow Daily Times
Glasgow Republican
Greensburg Record Herald
Greenville Leader News
Harlan Daily Enterprise
Harrodsburg Herald
Hartford Ohio County Times News
Henderson Gleaner
Hodgenville Larue County Herald News
Hopkinsville KY New Era
Irvine Citizen Voice & Times
LaGrange Oldham Era
Lancaster Central Record
Lancaster Garrard County News
Lawrenceburg Anderson News
Lebanon Enterprise
Leitchfield Grayson Co. News Gazette
Lexington Herald Leader
Liberty Casey County News
London Sentinel Echo
Louisville Courier Journal
Madisonville Messenger
Manchester Enterprise
Marion Crittenden Press
Maysville Ledger Independent
Middlesboro Daily News
Morehead News
Morganfield Union County Advocate
Mt. Sterling Advocate
Mt. Vernon Signal
Munfordville Hart County News Herald
New Castle Henry County Local
Nicholasville Jessamine Journal
Owensboro Messenger Inquirer
Owenton News Herald
Owingsville Bath County News Outlook
Paducah Sun
Paris Bourbon County Citizen/Advertiser
Paris Bourbon Times
Pineville Sun
Princeton Times Leader
Providence Journal Enterprise
Somerset Pulaski News Journal

Radcliff Sentinel
Richmond Register
Russell Springs Russell County News
Russell Springs Times Journal
Sebree Banner
Shelbyville Sentinel News
Shephersville Pioneer News
Smithland Livingston Ledger
Somerset Commonwealth Journal
Springfield Sun
Stanford Interior Journal
Sturgis News
Taylorsville Spencer Magnet
Beattyville Three Forks Tradition
Versailles Woodford Sun
Warsaw Gallatin County News
Whitley City McCreary County Record
Wickliffe Advance Yeoman
Williamsburg News Journal
Williamstown Grant County News
Winchester Sun

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

January 5, 2000

To: All parties of record

RE: Case No. 1999-430

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

Honorable Douglas Brooks
Senior Counsel Specialist
Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232 2010

Honorable Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601

John Stapleton
Director of Energy
Natural Resources and Environmental
Protection
663 Teton Trail
Frankfort, KY 40601

Honorable David F. Boehm
Honorable Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, OH 45202

Mr. Walter F. Bell
Executive Director
Louisville Resource Conservation
Council
P. O. Box 4174
Louisville, KY 40204 0174

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 99-430

O R D E R

This matter arises upon the motion of the Louisville Resource Conservation Council ("LRCC") for full intervention. It appears to the Commission that the LRCC has a special interest which is not otherwise adequately represented, and that such intervention is likely to present issues and develop facts that will assist the Commission in fully considering the matter without unduly complicating or disrupting the proceedings. The Commission also recognizes that a procedural schedule was established in this proceeding by Order dated December 10, 1999. The Commission, being otherwise sufficiently advised, finds that the LRCC should be granted full rights of a party in this proceeding and should accept the procedural schedule as it now stands.

IT IS HEREBY ORDERED that:

1. The motion of the LRCC to intervene is granted, and the LRCC shall accept the existing procedural schedule.

2. The LRCC shall be entitled to the full rights of a party and shall be served with the Commission's Orders and with filed testimony, exhibits, pleadings, correspondence, and all other documents submitted by parties after the date of this Order.

3. Should the LRCC file documents of any kind with the Commission in the course of these proceedings, it shall also serve a copy of said documents on all other parties of record.

Done at Frankfort, Kentucky, this 5th day of January, 2000.

By the Commission

ATTEST:

Helen C Helton

Executive Director

(FAX)

RECEIVED
DEC 2 0 1999
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN OF)
LOUISVILLE GAS AND ELECTRIC COMPANY) Case No. 99-430
AND KENTUCKY UTILITIES COMPANY)

MOTION FOR FULL INTERVENTION

COMES NOW the Louisville Resource Conservation Council (LRCC), and moves, pursuant to 807 KAR 5:001 Section 3(8), for full intervention in the above-captioned proceeding. In support of this Motion for Full Intervention, LRCC states as follows:

1. LRCC is a 501(c)(3) non-profit agency established in 1990 and incorporated under the laws of the Commonwealth of Kentucky to promote and support conservation of energy, water, and other consumable natural resources. LRCC provides direct technical assistance in management of energy use and cost to public and private non-profit building operators served by LouisvillefGas and Electric Company (LG&E), and has worked to develop utility and non-utility resources in support of energy conservation. LRCC's staff of two has 27 years experience in residential and commercial energy management and related service delivery programs.

2. LRCC was a party to the joint settlement agreement in Case No. 93-150, which led to demand-side management (DSM) programming for LG&E customers. As a member of the LG&E DSM Collaborative since its inception, LRCC has been an active participant in the design and implementation of LG&E's DSM programs. For two years LRCC operated LG&E's DSM program for non-profit community service agencies.

3. The agencies served by LRCC and other similarly situated energy users will be affected by the matters under consideration, and LRCC has a special interest in this regard that is not otherwise adequately represented by the parties to this proceeding. Full intervention status for LRCC will likely result in the presentation of issues and/or the development of facts that will assist the Commission in fully considering the matter without unduly complicating or disrupting the proceeding.

WHEREFORE, LRCC asks that this Motion for Full Intervention be granted, and that LRCC be provided with all pleadings, orders, testimony, or other documents that have been or will be filed in this matter.

Respectfully Submitted,

Walter F. Bell

Walter F. Bell
Executive Director
Louisville Resource Conservation Council
PO Box 4174
Louisville, Kentucky 40204-0174

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

December 17, 1999

To: All parties of record

RE: Case No. 1999-430

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

Honorable Douglas Brooks
Senior Counsel Specialist
Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232 2010

Honorable Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601

John Stapleton
Director of Energy
Natural Resources and Environmental
Protection
663 Teton Trail
Frankfort, KY 40601

Honorable David F. Boehm
Honorable Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, OH 45202

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 99-430

O R D E R

This matter arising upon the motion of the Kentucky Industrial Utility Customers, Inc. ("KIUC") for full intervention, and it appearing to the Commission that the KIUC has a special interest which is not otherwise adequately represented, and that such intervention is likely to present issues and develop facts that will assist the Commission in fully considering the matter without unduly complicating or disrupting the proceedings, and this Commission being otherwise sufficiently advised,

IT IS HEREBY ORDERED that:

1. The motion of the KIUC to intervene is granted.

2. The KIUC shall be entitled to the full rights of a party and shall be served with the Commission's Orders and with filed testimony, exhibits, pleadings, correspondence, and all other documents submitted by parties after the date of this Order.

3. Should the KIUC file documents of any kind with the Commission in the course of these proceedings, it shall also serve a copy of said documents on all other parties of record.

Done at Frankfort, Kentucky, this 17th day of December, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

December 10, 1999

Honorable Douglas Brooks
Senior Counsel Specialist
Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY. 40232 2010

Honorable Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

John Stapleton
Director of Energy
Natural Resources and Environmental
Protection
663 Teton Trail
Frankfort, KY. 40601

RE: Case No. 1999-430

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	)))	CASE NO. 99-430

ORDER

The Commission, on its own motion, hereby initiates its review of the Joint Integrated Resource Plan ("IRP") of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") filed on November 22, 1999 pursuant to 807 KAR 5:058. LG&E and KU are required by 807 KAR 5:058, Section 10, to publish, in a form prescribed by the Commission, notice of their filing in a newspaper of general circulation in their service areas. The notice must be published within 30 days of the filing date of this IRP. The Commission finds that the following format should be used when publishing notice of the IRP filing:

> On November 22, 1999, Louisville Gas and Electric Company and Kentucky Utilities Company filed their 1999 Joint Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Louisville Gas and Electric Company and Kentucky Utilities Company and a description of the existing and planned conservation programs, load management programs and generating facilities they intend to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utilities, and file written comments on the plan.
>
> Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Helen C. Helton, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, KY 40602.

The newspaper notice should be published as soon as reasonably possible after the receipt of this Order. The publication of this notice is in addition to LG&E and KU's responsibility under 807 KAR 5:058, Section 2(2), to provide notice, immediately upon filing their IRP, to intervenors in their most recent IRP proceedings, that their plan has been filed and is available from the utilities upon request.

In addition to the notice requirements set forth above, the Commission, on its own motion, hereby adopts the schedule included in Appendix A, attached hereto and incorporated herein, which establishes the procedural dates for this proceeding. Pursuant to 807 KAR 5:058, Section 2(3), this schedule may include interrogatories, informal conferences, comments, and staff reports.

IT IS THEREFORE ORDERED that:

1. LG&E and KU shall publish the notice set forth herein as required by 807 KAR 5:058, Section 10.

2. The procedural schedule set forth in Appendix A shall be followed in this case.

Done at Frankfort, Kentucky, this 10th day of December, 1999.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO THE ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 99-430 DATED 12/10/99

Initial interrogatories to LG&E and KU shall be filed no later than 01/25/00

LG&E's and KU's responses to initial interrogatories shall be filed no later than 02/23/00

Supplemental interrogatories to LG&E and KU shall be filed no later than 03/22/00

LG&E's and KU's responses to supplemental interrogatories shall be filed no later than 04/17/00

An Informal Conference will be held at 10:00 a.m., Eastern Standard Time, in the Commission's offices at 211 Sower Boulevard, Frankfort, Kentucky, for the purpose of discussing issues related to LG&E's and KU's 1999 IRP filing 05/12/00

Intervenors shall have the option of filing written comments on issues related to LG&E and KU's 1999 IRP filing no later than. 06/05/00

LG&E and KU shall have the option to file written comments in reply to any written comments from intervenors no later than 06/30/00

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

November 23, 1999

Honorable Douglas Brooks
Senior Counsel Specialist
Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY. 40232 2010

Honorable Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

John Stapleton
Director of Energy
Natural Resources and Environmental
Protection
663 Teton Trail
Frankfort, KY. 40601

RE: Case No. 1999-430

We enclose one attested copy of the Commission's Orders in the above case.

Sincerely,
Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosures

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 99-430

ORDER

This matter arising upon the motion of the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("Attorney General"), filed November 16, 1999, pursuant to KRS 367.150(8), for full intervention, such intervention being authorized by statute, and this Commission being otherwise sufficiently advised,

IT IS HEREBY ORDERED that the motion is granted, and the Attorney General is hereby made a party to these proceedings.

Done at Frankfort, Kentucky, this 23rd day of November, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 99-430

ORDER

This matter arising upon the motion of the Kentucky Natural Resources and Environmental Protection Cabinet, Department for Natural Resources, through its Division of Energy ("NREPC"), filed November 16, 1999, for full intervention, and it appearing to the Commission that the NREPC has a special interest which is not otherwise adequately represented, and that such intervention is likely to present issues and develop facts that will assist the Commission in fully considering the matter without unduly complicating or disrupting the proceedings, and this Commission being otherwise sufficiently advised,

IT IS HEREBY ORDERED that:

1. The motion of the NREPC to intervene is granted.

2. The NREPC shall be entitled to the full rights of a party and shall be served with the Commission's Orders and with filed testimony, exhibits, pleadings, correspondence, and all other documents submitted by parties after the date of this Order.

3. Should the NREPC file documents of any kind with the Commission in the course of these proceedings, it shall also serve a copy of said documents on all other parties of record.

Done at Frankfort, Kentucky, this 23rd day of November, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

BOEHM, KURTZ & LOWRY
ATTORNEYS AT LAW
2110 CBLD CENTER
36 EAST SEVENTH STREET
CINCINNATI, OHIO 45202
TELEPHONE (513) 421-2255

TELECOPIER (513) 421-2764

RECEIVED

NOV 2 2 1999

PUBLIC SERVICE
COMMISSION

Via Overnight Mail

November 19, 1999

Hon. Helen Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
Frankfort, Kentucky 40601

Re: In The Matter Of: Joint Integrated Resource Plan of Louisville Gas & Electric Company and Kentucky Utilities Company, Case No. 99-430.

Dear Ms. Helton:

Please find enclosed the original and ten copies of the Petition to Intervene of Kentucky Industrial Utility Customers, Inc. in the above-referenced matter. By copy of this letter, all parties listed on the Certificate of Service have been served.

Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY

MLK/kew
Attachment
cc: Certificate of Service
Richard Raff, Esq. (Via Telefax)

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy, by regular U.S. mail (unless otherwise noted) to all parties on this 19th day of November, 1999.

Hon. Elizabeth E. Blackford
Utility & Rate Intervention Division
1024 Capital Holding Center Dr.
Suite 200
Frankfort, KY 40601

Hon. Kendrick Riggs
Ogden Newell & Welch
1700 Citizens Plaza
500 W. Jefferson Street
Louisville, KY 40202-2874
(Via Telefax Transmission)

Hon. Douglas M. Brooks
Louisville Gas & Electric Company
220 West Main Street
P.O. Box 32010
Louisville, KY 40202

Mr. Ronald L. Wilhite
Vice President of Regulatory Affairs
Kentucky Utilities Company
220 West Main Street
Louisville, KY 40202

Iris Skidmore, Esq.
Ronald P. Mills, Esq.
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 4601

Michael L. Kurtz, Esq.

RECEIVED
NOV 22 1999
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of: Joint Integrated Resource Plan of Louisville Gas & Electric Company and Kentucky Utilities Company : Case No. 99-430

PETITION TO INTERVENE OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Pursuant to K.R.S. §278.310 and 807 KAR 5:001 Section 3(8), Kentucky Industrial Utility Customers, Inc. ("KIUC") requests that it be granted full intervenor status in the above-captioned proceeding and states in support thereof as follows:

1. KIUC is an association of the largest electric and gas public utility customers in Kentucky. The purpose of KIUC is to represent the industrial viewpoint on energy and utility issues before this Commission and before all other appropriate governmental bodies. The members of KIUC who purchase electricity from Kentucky Utilities Company ("KU") and Louisville Gas & Electric Company ("LG&E") and who will participate herein are: Carbide/Graphite Group, Inc., E.I. DuPont de Nemours & Company, Ford Motor Company, Kosmos Cement Company, Philip Morris, USA, Rohm & Haas Company, General Electric-Appliance Park, Geon Company, Lexmark International, Inc., Square D. Company, Clopay Plastic Products Company, Inc., Dow Corning Corporation, Toyota Motor Manufacturing, USA, and Westvaco. KIUC will supplement its Petition with the names of additional participating members as this information becomes known.

2. The matters being decided by the Commission in this case may have a significant impact on the rates paid by KIUC for electricity. Electricity represents a significant cost of doing business for KIUC. The attorneys for KIUC authorized to represent them in this proceeding and to take service of all documents are:

David F. Boehm, Esq.
Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
2110 CBLD Center, 36 East Seventh Street
Cincinnati, Ohio 45202
Ph: 513-421-2255 Fax: 513-421-2764
E-Mail: KIUC@aol.com

3. The position of KIUC cannot be adequately represented by any existing party. KIUC intends to play a constructive role in the Commission's decision making process herein and KIUC's participation will not unduly prejudice any party.

WHEREFORE, KIUC requests that it be granted full intervenor status in the above captioned proceeding.

Respectfully submitted,

David F. Boehm, Esq.
Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
2110 CBLD Center, 36 East Seventh Street
Cincinnati, Ohio 45202
Ph: (513) 421-2255 Fax: (513) 421-2764
E-Mail: KIUC@aol.com

COUNSEL FOR KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

November 19, 1999

LG&E ENERGY®

Ronald L. (Ron) Willhite
Vice President - Regulatory Affairs

LG&E Energy Corp.
220 West Main Street
P.O. Box 32030
Louisville, Kentucky 40232
502-627-2044
502-627-2585 FAX

November 22, 1999

RECEIVED
NOV 22 1999
PUBLIC SERVICE
COMMISSION

Helen C. Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602-0615

RE: CASE NO. 99-430
The Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company

Dear Ms. Helton:

Enclosed for filing is the Joint Integrated Resource Plan (IRP) of Louisville Gas and Electric Company and Kentucky Utilities Company. The IRP is consistent with 807 KAR 5:058.

Accompanying the IRP filing is a Petition for Confidential Protection relating to projected power production costs and projected sales rates. Therefore, the Company's are filing with the Commission 15 bound copies from which the information sought for confidential treatment has been redacted and one unbound, reproducible copy. Another bound copy is being filed highlighting the information sought to be confidential.

Sincerely,

Ronald L. Willhite

Ronald L. Willhite
Vice President-Regulatory Affairs

Enclosures

cc:	Hon. Elizabeth E. Blackford	(Petition plus 1 redacted copy)
	Hon. Michael L. Kurtz	(Petition plus 1 redacted copy)
	Hon. Iris Skidmore	(Petition plus 1 redacted copy)

RECEIVED

NOV 22 1999

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	**CASE NO. 99-430**

PETITION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CONFIDENTIAL PROTECTION

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("the Companies") (collectively, the "Companies") petition the Public Service Commission ("Commission") pursuant to 807 KAR 5:001 Section 7 to grant confidential protection to certain information contained in the Companies' 1999 Joint Integrated Resource Plan relating to projected fuel and power production costs, projected sales rates and revenue requirements, and capital costs of supply-side resource alternatives. In support of this Petition, LG&E and KU state as follows:

1. Pursuant to Section 2(1)(a)1 of 807 KAR 5:058, Integrated Resource Planning by Utilities, the Companies have filed their 1999 Joint Integrated Resource Plan ("1999 IRP") with the Commission for review. Among the items contained in the 1999 IRP are projected power production costs and projected rates and revenue requirements. This information, the inputs to the information and the total values containing this information is all confidential and proprietary information, the disclosure of which would provide unfair commercial advantages to the Companies' competitors in the wholesale market for bulk and off-system power sales and to coal suppliers who bid to sell coal to the Companies.

2. The Commission reviewed KU's last Integrated Resource Plan in Case No. 96-173, In the Matter of a Review Pursuant to 807 KAR 5:058 of the 1996 Integrated Resource Plan of Kentucky Utilities Company, and reviewed LG&E's last Integrated Resource Plan in Case No. 93-425, In the Matter of a Review Pursuant to 807 KAR 5:058 of the 1993 Integrated Resource Plan of Louisville Gas and Electric Company. Since then, the electric utility industry has undergone profound changes. The passage of the Energy Policy Act of 1992 has brought extensive competition to the electric wholesale market and introduced numerous new marketers, brokers, and clearinghouses, and many new sources of non-utility generation of power. The change in federal law has resulted in electric utilities filing nondiscriminatory open-access transmission tariffs and applications for approval of market-based wholesale power rates with the Federal Energy Regulatory Commission. The FERC has authorized utilities, including the Companies, to charge market-based prices for wholesale power transactions and approved open-access transmission services tariffs. See, e.g., Kentucky Utilities Company, 71 FERC Par. 61,250 (May 31, 1995). All of these regulatory developments and changes in the law have created a robust and competitive wholesale market for bulk and off-system power sales.

3. Under KRS 61.878(1)(c), commercial information, generally recognized as confidential, is protected if disclosure would cause competitive injury. The Companies' projections of their power production costs from 1999 through 2010 constitute information that is generally recognized as confidential. This information must remain confidential if the Companies are to continue to be able to vigorously compete for wholesale sales and purchase wholesale sales at competitive prices. Public disclosure of this information would result in purchases of bulk and off-system sales at higher prices and the loss of or reduced margins on wholesale sales, and thus injury to both the Companies and their customers, and would give commercial advantages to the

Companies' competitors. The power production cost information for which the Companies seeks protection from public disclosure is contained in Sections 8-3(b)12.c,.e and .g of the 1999 IRP. These sections contain the Companies' projected costs of production of power, including projected costs of fuel and operation and maintenance expenses. These projections are for the period 1999 through 2010 and are developed internally by the Companies personnel. This information is not on file with the FERC, SEC or other public agency, is not available from any commercial or other source outside the Companies, and is limited in distribution within the Companies to those employees who have a business reason to have access to such information. Disclosure of this information would provide the Companies' competitors in the wholesale market the minimum price the Companies could charge for bulk and off-system sales of power. Disclosure of this information also would provide buyers of the Companies' off-system and bulk power a competitive advantage. This information would allow buyers to determine the Companies' margins on such sales and create a bargaining position superior to the Companies' position, placing the Companies at a competitive disadvantage.

4. Similar projections of power production costs are contained in four of the reports in Volumes II and III-Technical Appendix to the 1999 IRP. The Optimal Integrated Plan Analysis contains similar projected power production cost information in Tables 2 through 5 in Appendix A. The Analysis of Supply-Side Alternatives contains similar projections of power productions costs in Exhibits 5(a) and (b) and Exhibit 8 in Appendix A. The Clean Air Act Amendments of 1990 Compliance Plan contains similar information concerning projections of power productions costs in the charts in Appendix E. Finally, the Analysis of Reserve Margin Planning Criteria contains similar projections of and inputs for calculating the projections of the Companies' cost of producing power in Tables 3 and 5 in Appendix A. In addition, projected fuel forecast information is contained

in Volume II Technical Appendix Tab II Data Sources. This information in the four reports in Appendix III and the fuel projections in Appendix II are confidential and proprietary, the disclosure of which would provide the Companies' competitor a commercial advantage in the wholesale power markets.

5. This information also contains the Companies' projected cost of fuel as part of the Companies projections of the cost of the production of power. Disclosure of this information would provide coal suppliers with the Companies' expectations about the price of coal and other fuels in the future and would allow coal suppliers to take advantage of the Companies' solicitations by increasing their bids to the maximum extent possible, thereby causing higher fuel prices for the Companies' customers.

6. Projected sales prices and revenue requirements are contained in Sections 5.3, 7.7(b) and 9 of the IRP and in Volume II Technical Appendix at page 25 of Tab I Forecast Report in a graph titled "KY Retail Price Forecasted Rates of Change", and in certain pages in Tab II Data Sources in Volume II Technical Appendix. This information is confidential and proprietary information which should not be disclosed in the public record. Disclosure of this information would provide the Companies' competitors with a commercial advantage in the wholesale market for off-system and bulk power sales and allow such competitors to underbid the Companies or submit maximum bids in comparison to the Companies' bids for the sale of wholesale power. Disclosure of this information also would provide an unfair commercial advantage to some of the Companies' largest retail and wholesale customers who currently are negotiating power requirement contracts with the Companies.

7. Capital costs of supply-side resource alternatives are contained in Section 8, Table 8(2)(c), Table 8.3.(b).12.d,f and in Volume III, Technical Appendix, Analysis of Supply-Side

Alternative, Exhibits 4 and 6. This information is confidential and proprietary information which should not be disclosed in the public record. Disclosure of this information would provide the Companies' competitors with a commercial advantage in the wholesale market for off-system and bulk power sales and in the market for generation asset acquisitions. Disclosure of this data would lead to the acquisition of generation assets in the future at higher prices, which in turn would give commercial advantage to competitors, all to the detriment of KU's and LG&E's customers.

8. The Companies does not object to disclosure of the confidential information, pursuant to a protective agreement, to the Attorney General or other intervenors with a legitimate interest in reviewing the confidential information for the purpose of commenting on the Companies' 1999 IRP. The Companies will provide a protective agreement to intervenors that is nearly identical to the protective agreement utilized by the parties in KU's last IRP proceeding, Case No. 96-173.

9. In accordance with the provisions of 807 KAR 5:001 Section 7, one copy of the Companies' 1999 IRP with the confidential information highlighted and ten (10) copies of the Companies' 1999 IRP with the confidential information obscured is filed with the Commission.

WHEREFORE, Louisville Gas and Electric Company and Kentucky Utilities Company respectfully requests that the Commission grant confidential protection to the information designated as confidential for a period of five years from the date of the filing of the 1999 Joint Integrated Resource Plan, or in the alternative, schedule an evidentiary hearing on all factual issues.

Respectfully submitted,

Douglas M. Brooks
Senior Counsel Specialist, Regulatory
220 West Main Street
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(502) 627-2557
Counsel for Louisville Gas and Electric Company
and Kentucky Utilities Company

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing Petition for Confidential Protection was served on this 22nd day of November 1999, by mailing a copy thereof, postage prepaid, through the U.S. Mail to Elizabeth Blackford, Assistant Attorney General, Division of Rate Intervention, P.O. Box 2000, Frankfort, KY 40602-2000; Michael Kurtz, Boehm, Kurtz and Lowry, 2110 CBLD Center, 36 East Seventh Street, Cincinnati, Ohio 45202; Iris Skidmore, Counsel for Natural Resources and Environmental Protection Cabinet, Office of legal Services, Fifth Floor, Capital Plaza Tower, Frankfort, KY 40601.

Douglas M. Brooks
Counsel for Louisville Gas and Electric Company
and Kentucky Utilities Company

LG&ENERGY

LG&E Energy Corp.
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232

June 30, 2000

RECEIVED

JUN 30 2000

PUBLIC SERVICE COMMISSION

Mr. Martin J. Huelsmann
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40602

Re: PSC Case No. 99-430

Dear Mr. Huelsmann:

Enclosed for filing are the original and 10 copies of the Reply Comments of Louisville Gas and Electric Company and Kentucky Utilities Company to the Attorney General's and Kentucky Division of Energy's filed comments related to the 1999 Joint Integrated Resource Plan.

The Reply is submitted on behalf of the Companies in accordance with the procedural schedule established in the Commission's Order dated December 10, 1999 in Case No. 99-430.

Sincerely,

Ronald L. Willhite

Ronald L. Willhite
Director
Rates and Regulatory Affairs

RLW:dl

Enclosures

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

**THE JOINT INTEGRATED RESOURCE PLAN)
OF LOUISVILLE GAS AND ELECTRIC COMPANY) CASE NO. 99-430
AND KENTUCKY UTILITIES COMPANY)**

**REPLY COMMENTS OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILTIES COMPANY
TO THE COMMENTS OF THE
ATTORNEY GENERAL
AND KENTUCKY DIVISION OF ENERGY**

Louisville Gas and Electric Company and Kentucky Utilities Company ("Companies") file these Reply Comments to the Comments of the Attorney General ("AG") and Kentucky Division of Energy ("KDOE") related to the 1999 Joint Integrated Resource Plan ("IRP") in accordance with the procedural schedule established in the Commission's Order dated December 10, 1999.

REPLY TO THE COMMENTS OF THE ATTORNEY GENERAL

Potential Capacity from OVEC.

The Attorney General asserts that the Companies did not adequately include the possibility of the closure of the U.S. Enrichment Corporation's Portsmouth Gaseous Diffusion Plant in the mix of resources utilized to meet future native load needs. With the uncertainty surrounding this capacity at the time the Companies were preparing the IRP, the Companies could not rely on this resource in the near term to meet the growing requirements of the native load customers. The IRP represents the Companies' best analysis at the time of development taking into account reasonably expected conditions. The Companies' planning process is not static, but ongoing. Therefore, events such as the recent announcements concerning the closure of the Piketon plant are monitored and evaluated as a resource to meet the future needs of the native load customers as part of the ongoing process. The IRP process permits the ability to incorporate changed conditions which influence the cost effectiveness of resource alternatives and the ability to adjust the plan.

Pending Environmental Regulations.

The Attorney General asserts that the Companies did not adequately include the impact of pending environmental regulations in the IRP. This is not true with respect to future programs aimed at the reduction of "regulated" air pollutants (i.e. SO_2, NOx, etc.) under the Clean Air Act. The Companies have assessed the impact of those programs through the IRP process. Although there are various proposals for the reduction of carbon dioxide emissions, no requirements are in place at this time. The 1997 Kyoto Protocol on Climate Change has not been sent to the Senate for ratification. The current Administration has indicated that until developing countries also make commitments to participate in greenhouse gas limitations, it will not submit the protocol to the Senate for advice and consent, thereby delaying indefinitely any possibility of ratification. The Companies did evaluate a possible carbon tax as part of the supply-side screening study, but found that it had little impact on the selection of alternatives. The Companies continually monitor the impact of potential environmental regulatory programs and adjust plans accordingly.

Demand-Side Management.

All of the DSM programs proposed in the IRP reduce load resulting in 219 MW of planned reductions, not just the 46 MW of the planned DSM capacity as stated by the Attorney General's office. The Companies realize that the qualitative screening process is subjective, but it is a necessary step to reduce the number of alternatives down to a manageable level. In addition, the screening process utilized by the Companies is widely applied and accepted within the industry. The Companies are proposing the largest set of DSM programs ever in the Commonwealth of Kentucky.

Renewable Fuel Resources in Screening Process.

The Attorney General asserts that the Companies' planning models may have a bias against renewable resources. The screening process evaluates the total cost of each resource operating over a range of capacity factors. Under each scenario (fuel, capital cost, heat rate) evaluated in the screening analysis, the first, second, and third least cost options are determined at each capacity factor (0%, 10%, 20%, etc.) evaluated. The options are then ranked according to the number of times they appear as either the first, second, or third least cost alternative. The top alternatives are reviewed and passed onto the integrated analysis. The IPP Hydro facility that the AG is referring to was determined to be a least cost resource and was passed onto the integrated analysis.

It is inappropriate to assess the potential generation above the capacity factor being evaluated, as the AG indicated should be performed, because all capacity factor levels are evaluated in the screening curve analysis. As the AG indicates, a renewable source with no fuel cost operating at a 10% capacity factor has the potential to generate additional energy at a lower cost than, say, a coal-fired facility. Likewise, a coal-fired facility operating at 10% capacity factor has the potential to generate additional energy at a lower cost than a facility with higher fuel cost, such as a gas-fired combustion turbine. This type of "benefit" should not be included in an evaluation that is designed to compare the cost of a resource at a specific capacity factor.

The AG asserts that since renewable resources have no fuel costs, they would be run full out continuously regardless of the capacity needs of the utility. This in essence would displace existing generation. The AG further states that any excess power generated can be sold in the wholesale market. The Integrated Resource Plan is developed based upon the needs of the native load customers only and not on the ability to make sales in the wholesale marketplace. Typically the availability of a renewable resource (wind, solar or run-of-the river hydro) is beyond the control of the developer and cannot easily be sold as a product in the wholesale market. Further, <u>any</u> resource added to the Companies supply mix that generates excess power can be sold in the wholesale market.

The AG presents an example as a way of explaining the alleged bias against renewable resources. In this example, the AG calculates a value of excess power above the specific capacity factor being evaluated. The AG argues that the IPP Hydro (the resource used in the example) operated at a 10% capacity factor has excess power available up to 60% capacity factor maximum. The value of this excess power is determined using the total 1998 actual production cost of the LG&E/KU system applied to the excess energy and subtracted from a 30-year levelized cost per kW for the IPP hydro operating at 10%. This argument has several fallacies. First and foremost, as discussed above the screening process evaluates the total cost of the IPP Hydro at a specific operating capacity factor. It is not appropriate to evaluate the potential generation above this operating point. Second, the AG is using a single annual number and subtracting this from a 30-year levelized value to come up with the value of excess power. Finally, the total 1998 actual production cost used in the AG's example includes fixed cost that would not be avoidable in the AG's example presented. The IPP Hydro facility evaluated in the screening analysis should have been presented as a resource only available at a 60% capacity factor level and the screening curve graph presented as Figure 8.5(c)-1 in the Companies' 1999 Joint IRP should have been as shown in Exhibit 1 attached to the Companies' Reply Comments.

IPP Hydro Evaluation in Optimal Plan.

The AG asserts that there is an error in the Companies' optimization model in that it does not select what the AG perceives as the least cost option at all capacity factor levels from 0% to 60%. As previously stated the AG's arguments concerning renewable resources (including the IPP Hydro project) are invalid. The IPP Hydro project was evaluated along with all other resource alternatives in the integrated analysis. The project was modeled with the specific characteristics as proposed by the developer of the facility. It is a run-of-the-river hydro facility which is projected to generate a specific level of energy based upon historical river flow. This equates to a 60% capacity factor facility. The proposal also requires a specific energy payment that would allow the developer to finance the project based upon a certain payment stream. In other words, if the project only generated at a 10% capacity factor, the developer would still require the full payment based upon generating at a 60% capacity factor. Thus, it is not valid to evaluate this resource at any level of generation except at the designed 60% unless the payment stream is aligned with the operation at a different level of generation.

Studies were performed where the IPP Hydro facility was assumed to be installed and other resources were optimized around this project. The least cost plan with the IPP Hydro facility as part of the future resource mix resulted in a higher cost than the plan selected and presented in the Companies' IRP. Therefore, to have the IPP Hydro project as part of the Companies' IRP would create a resource plan that would be more costly to the customers. The AG's statement that there must be an error in the optimization model lacks merit.

<u>Ohio Falls Rehabilitation</u>.

The AG asserts that the Companies overlooked the rehabilitation of the Ohio Falls station as a resource in the IRP. As a result of LG&E's 1993 IRP, which indicated that rehabilitation of the Ohio Falls station in 2003 would be part of the least cost plan for the customers, the Companies initiated a detailed analysis for this project. Since that detailed analysis was not complete at the time the 1999 IRP was filed, it was not included as a resource alternative. However, as the Companies have indicated, the Integrated Resource Plan is the documentation of an ongoing process. The Companies have and will continue to evaluate resource alternatives on an ongoing basis. When the Ohio Falls study is complete, this resource will be considered in future evaluations.

REPLY TO THE COMMENTS OF THE KENTUCKY DIVISION OF ENERGY

The KDOE has submitted extensive comments that are far afield from the obligations of the companies as regulated public utilities. In addition, the KDOE outlines procedures that are in direct contradiction to the requirements of the IRP and the longstanding policies of the Commission for the evaluation for granting of certificates of convenience and necessity. The Companies' comments, while not exhaustive, address the major points offered by the KDOE.

The Purpose of Integrated Resource Planning.

The Companies agree that the purpose of Integrated Resource Planning is the same as least cost planning. However, the Companies disagree with the KDOE's implication that the Companies did not evaluate supply-side and demand-side options on an equal financial basis. This was accomplished by the Companies evaluation of both supply-side and demand-side options in the integrated analysis portion of the IRP using the PROVIEW module of PROSCREEN. The KDOE's confusion may be the result of their review and misplaced significance on the manner in which supply-side and demand-side alternatives are treated in the screening phase. Screening curves are a widely accepted and proven method to screen supply-side alternatives. Screening curves are not suited to screen DSM options since most DSM options do not have fuel costs or capacity factors. This is one reason the California Standard tests were created – to adequately screen DSM programs from multiple perspectives.

The Total Resource Cost (TRC) test was designed and created to evaluate DSM programs not supply-side alternatives as described in the book referenced by the KDOE, *Demand-Side Management*, by Clark W. Gellings and John H. Chamberlin.

> "The Total Resource Cost (TRC) test is a measure of the total net resource expenditures of a **DSM program** from the point of view of the utility and its ratepayers as a whole." [emphasis added]

KDOE'S Vision of the Future - A Well-Functioning Market for Energy Services.

The Companies agree with the KDOE regarding the benefits of customer choice and competitive markets. However, those markets do not exist today and it is uncertain as to when a competitive market for generation will be present in Kentucky.

The Present Reality: Pervasive and Chronic Market Barriers.

Most of the market barriers mentioned by the KDOE are beyond the scope of the IRP and beyond the influence of the Companies.

The Companies' Integrated Resource Plan.

1. Limited Number of DSM Options Considered.

The Companies agree that the long list of DSM alternatives is not exhaustive. However, the long list represents a combination of the most common DSM programs available in the market today, the programs receiving the most attention in the research and development community, and those programs having the greatest potential to reach the marketplace in the near term.

2. Category Confusion.

Each item in the long list was a DSM measure that could be included with or without other measures and designed to make a DSM program. The Companies did not want to limit itself to considering only one type of technology in a DSM category.

3. Faulty Screening Methodology.

The Companies chose the criteria used in the qualitative screening process to be consistent with the recommendations from the KPSC Staff Report in LG&E's 1993 IRP.

4. Excessively Stringent DSM Screening Cutoff Point.

While the qualitative screening process is subjective, it is a reasonable and necessary step to reduce the number of alternatives down to a manageable level.

5. Supply-Side Screening Problem.

The KDOE's shared concern with the AG regarding the evaluation of zero fuel costs technologies is addressed in the Companies' response to the AG's comments under the section titled <u>Renewable Fuel Resources in Screening Process</u>.

The KDOE implies that the Companies should use the TRC test as the main tool to screen DSM programs and that the Companies should screen more DSM programs. Because it takes a considerable amount of time and effort to design, model and evaluate a single DSM program the qualitative screening process is to narrow the number of programs to be further evaluated.

Market Transformation Program Options.

The Companies are continually looking for win-win opportunities for its customers and shareholders. There are many ways to transform a market: education, tax incentives, and governmental actions. Many of the KDOE ideas on how to transform the market are outside the scope of the IRP and are outside the control of the Companies.

Some of the comments the KDOE makes regarding market transformation are in direct conflict with the ideas expressed by the KDOE in regards to the purpose of the IRP. For example, promoting distributed generation could increase energy efficiency at the expense of an increase in the overall cost of service. The current market for distributed generation and certain renewable technologies is in high cost service areas, this is not the market in which our customers operate. Nevertheless, the Companies will continue to monitor the progress of distributed and renewable technologies and will actively promote them when they become a cost-effective choice for our customers in Kentucky.

A. Initiate a Comprehensive Market Transformation Program in the New Commercial Construction Sector.

The concept of establishing a non-regulated architectural/design firm is beyond the scope of the IRP.

B. Use Local Integrated Resource Planning (LIRP).

As the Companies indicated in response to the KDOE question 22 in the first set of interrogatories dated January 18, 2000: "The Companies will evaluate all projects in the context of least cost planning. To the extent that transmission and distribution projects can be deferred by the implementation of planned DSM programs the Companies will certainly evaluate this alternative."

C. Promote Cogeneration and Other Distributed Generation.

Each Company has on file with the Commission tariffs for the purchase of cogenerated power. The Companies will pursue distributed generation when it is in the mutual best interest of the customer and the Companies. Considering the low cost of retail electricity provided by the Companies, it is difficult to justify cogeneration or distributed generation at this time as is recognized in the IRP.

D. Support Statewide and Regional Market Transformation Initiatives

The Companies will evaluate all aspects of a regional alliance.

E. Launch a Kentucky Design Initiative.

This proposed initiative is beyond the scope of the IRP and beyond the influence of the Companies.

CONCLUSION

The 1999 Joint IRP of Louisville Gas and Electric Company and Kentucky Utilities Company includes contingent events in its forecasting and planning, but only when a reasonable bandwidth of certain possibilities and factual data can be reasonably established. The Companies' IRP recognizes the uncertainty associated with the planning process and the fact that multiple resource options are available. The Companies will continue to recognize this basic concept as part of the ongoing planning process wherein all options, including renewable resources and demand side management, are evaluated without bias in favor of one option over others.

In consideration of the Companies' Reply Comments to the Attorney General and Kentucky Division of Energy, the Companies request the Public Service Commission Staff accordingly issue its report summarizing its review of the 1999 Joint IRP at its earliest convenience.

Respectfully Submitted

Ronald L Willhite

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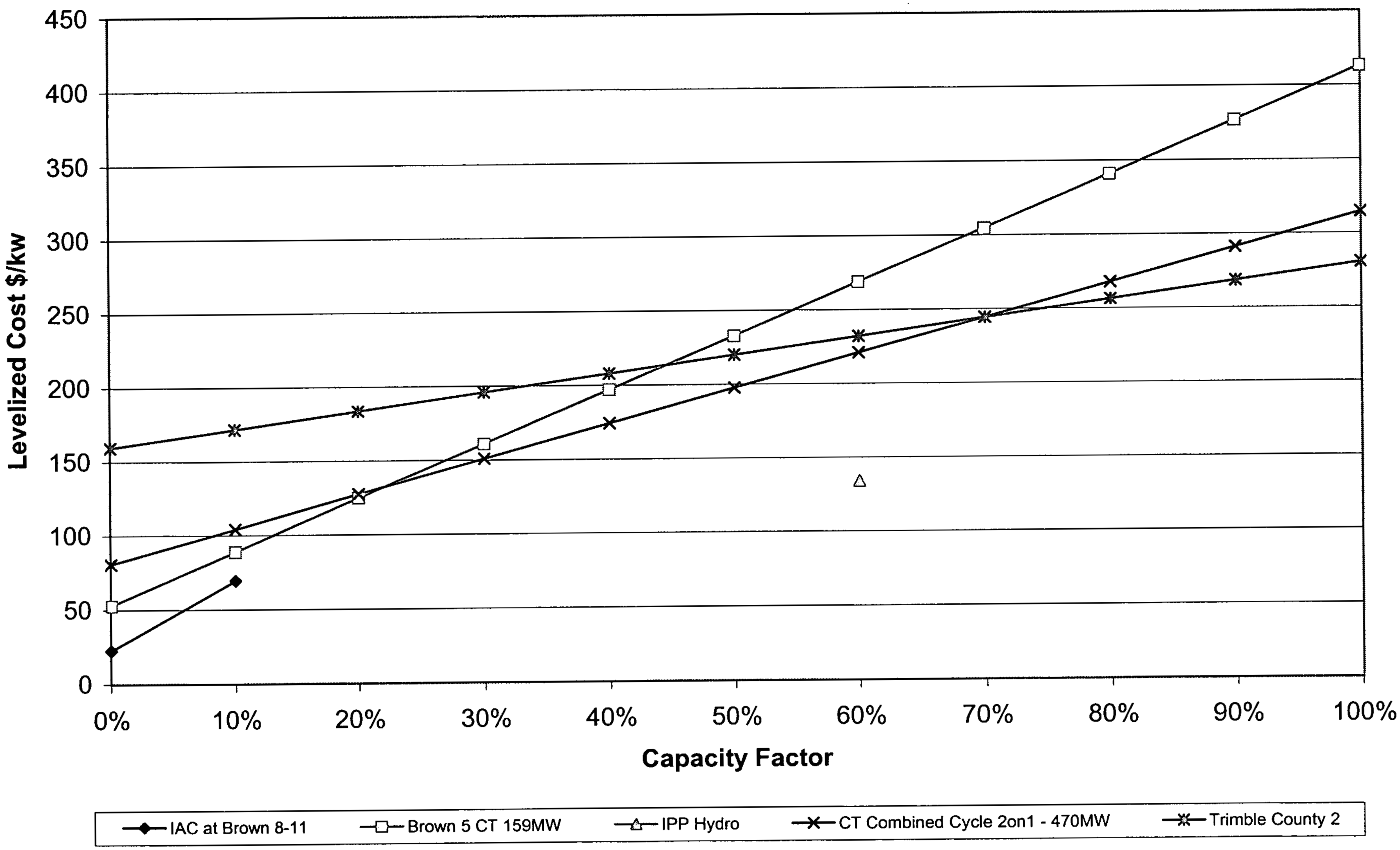
(502) 627-2557

Counsel for
Louisville Gas and Electric Company
Kentucky Utilities Company

Figure 8.(5)(c)-1
Least Costly Technologies
Base Capital, Base Heatrate, Base Fuel



CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing was served via U. S. Mail, First-Class, postage prepaid, this 30th day of June, 2000.

Hon. Elizabeth E. Blackford
Office of the Attorney General
1024 Capital Center Drive
Frankfort, KY 40601

Hon. David F. Boehm
Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, OH 45202

John Stapleton
Director of Energy
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P.O. Box 4174
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Hon. Iris Skidmore
Hon. Ronald P. Mills
Office of Legal Services
Fifth Floor Capital Plaza Tower
Frankfort, KY 40601

Mary L. Gillespie

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A SUBSIDIARY OF
LG&E ENERGY

A SUBSIDIARY OF
LG&E ENERGY

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	)))	CASE NO. 99-430

Volume I
Integrated Resource Plan

November 22, 1999

4. FORMAT

4.(1) Organization

This plan is organized by using the Section and Subsection numbers found in the Administrative Regulation 807 KAR 5:058, "Integrated Resource Planning by Electric Utilities." This report is filed with the Public Service Commission of Kentucky in compliance with the aforementioned regulation.

The format of the report is outlined below.

I. Volume I

1) Table of Contents
2) Section 4. Format
3) Section 5. Plan Summary
4) Section 6. Significant Changes
5) Section 7. Load Forecasts
6) Section 8. Resource Assessment and Acquisition Plan
7) Section 9. Financial Information

II. Volume II. Technical Appendix

1) LG&E Energy and Demand Forecast
2) KU Energy and Demand Forecast

III. Volume III. Technical Appendix

1) Analysis of Reserve Margin Planning Criteria
2) Screening of Demand-Side Management Options
3) Analysis of Supply-Side Technology Alternatives
4) Clean Air Act Amendments of 1990 Compliance Plan
5) Optimal Integrated Resource Plan Analysis
6) Transmission Construction Projects
7) Recommendations from PSC on Past IRP Filings

4.(2) Identification of individuals responsible for preparation of the plan.

Lonnie E. Bellar, Manager of Generation Systems Planning

H. Bruce Sauer, Manager of Forecasting and Marketing Analysis

Greg B. Fergason, Coordinator, Regulatory Relations and DSM

Douglas A. Leichty, Senior Rate and Regulatory Analyst

SECTION 5-
PLAN SUMMARY

5. PLAN SUMMARY

5.(1) Description of the utility, its customers, service territory, current facilities, and planning objectives.

Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E) are investor-owned public utilities supplying electricity and natural gas to customers primarily in Kentucky. Both KU and LG&E are subsidiaries of LG&E Energy Corporation. LG&E Energy Corporation and KU Energy Corporation completed their merger transaction on May 4, 1998; KU became a subsidiary on that date. LG&E became a subsidiary on August 17, 1990. As the owners and operators of interconnected electric generation, transmission, and distribution facilities, KU and LG&E (the Companies) achieve economic benefits through operation as a single interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

KU supplies electric service to more than 478,000 retail customers in a service area which covers approximately 6,600 non-contiguous square miles in 77 counties of Kentucky and 5 counties in southwestern Virginia. KU also sells electric energy at wholesale for resale to 11 municipalities in Kentucky, Berea College (a privately-owned utility serving the city of Berea), and Pitcairn, Pennsylvania.

LG&E supplies electricity and natural gas to customers in the Louisville metropolitan area. LG&E provides electric service to more than 360,000 customers in Louisville and 16 surrounding counties covering approximately 700 square miles.

The Companies' retail customers include all customers served under the following service classes: residential, general service (small commercial and industrial), large commercial, large industrial (large power), and street lighting customers. Among the industries included in the service territory are coal mining, automotive and related industries, agriculture, primary metals processing, crude oil production, pipeline transportation, and the manufacture of electrical and other machinery and of paper and paper products.

The Companies' power generating system consists of 21 coal-fired units operated at 8 different steam generating stations: E. W. Brown, Cane Run, Ghent, Green River, Mill Creek, Pineville, Trimble County, and Tyrone. Gas-fired and/or oil-fired combustion turbines supplement the system during peak periods. The system is further augmented by hydroelectric facilities at Dix Dam, Lock 7, and Ohio Falls. The Companies do not own any nuclear facilities. The generating units for KU and LG&E are summarized in Tables 5.(1)-1. (See Table 8.(3)(b) in Section 8 for a detailed listing.)

Table 5.(1)-1
Generating Unit Totals for LG&E and KU

Totals	1999 Summer Net Capacity (MW)	1999 Winter Net Capacity (MW)
KU Coal	3005	3063
KU CT	746	881
KU Hydro	24	24
Total KU	**3775**	**3968**
LGE Coal	2404	2414
LGE CT	233	265
LGE Hydro	47	49
Total LGE	**2683**	**2728**
Coal	5409	5477
CT	979	1146
Hydro	71	73
Total	**6459**	**6696**

The Companies' net summer generating capability for 1999 is 6,459 megawatts. The Companies have purchase agreements in place with Electric Energy Incorporated (EEI) and Owensboro Municipal Utilities (OMU). The Companies' highest combined system peak demand of 6,357 megawatts occurred on July 30, 1999. Both Companies independently experienced their highest system peak demands on that date; KU reached a system peak demand of 3,764 megawatts at hour ending 15:00 Eastern Daylight Time (EDT), and LG&E reached a system peak demand of 2,612 megawatts at hour ending 16:00 EDT.

This report is a snapshot in time of an on-going resource planning process which the Companies believe is fundamental to all corporate planning. The various sections of this report define on-going and planned activities that collectively make up this process. The Companies review the planning alternatives and decisions annually as part of the on-going resource planning process. This process is continually evolving, and as such is a dynamic effort using state-of-the-art techniques and models as well as timely and pertinent information. All planning decisions are based on certain sets of assumptions and are subject to varying degrees of risk and uncertainty. Resource alternatives and the needs of native load customers are continually changing. It is only through an on-going planning process that there is assurance that the interests of the Companies' constituent groups are adequately addressed.

Meeting the needs of the Companies' customers requires the availability of sufficient resources to serve the customer's demand. Additional resources must also be available should there be an unexpected loss of generation, generation equipment problems, extreme weather conditions, or unanticipated load growth. Existing capacity resources consist of company-owned generating units and contracted purchased power from other generating or power marketing entities. In the integrated planning process, the economics and practicality of supply-side and demand-side options are examined to determine cost-effective responses to customers' needs. The IRP process encompasses: 1) establishment of a reserve margin target; 2) assessment of existing generating units and purchase power agreements; 3) future purchased power market analysis; 4) supply-side option analysis; and 5) demand-side option analysis. While the IRP represents the Companies' analysis of the best options to meet customer needs at a given point in time, the action plan is reviewed and re-evaluated prior to implementation. In addition to net Present Value Revenue Requirement (PVRR), which establishes the ordering of the IRP options, rate impact, shareholder effects, risks and flexibility are typically considered prior to making financial commitments.

While preparing this resource assessment and acquisition plan, the Companies were in possession of both the *Staff Report on the 1993 Integrated Resource Plan of the Louisville Gas & Electric Company* dated March 1995 and the *Staff Report on the 1996 Integrated Resource Plan of the Kentucky Utilities Company* dated March 1999. These reports summarize the Commission Staff's review of the utility filings and offer suggestions and recommendations to be considered in subsequent filings. The Companies have made every effort to address the suggestions and recommendations contained in both Staff reports. A summary of the ways in which those suggestions and recommendations were addressed is provided in the report titled *Recommendations in PSC Staff Reports on Past IRP Filings* in Volume III, Technical Appendix.

5.(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan;

Forecasting future energy and demand is important for the planning and control of the Companies' operations. The forecast is a tool for decisions regarding construction of facilities, such as: power plants, transmission lines, and substations, all of which are necessary for providing reliable service.

The desired outcome of the forecasting process is a reasonable estimate so that the Companies' strategies and goals of providing adequate and reliable electric service to its customers at the lowest reasonable cost can be attained. The sophisticated modeling techniques allow the energy and demand forecast to be tailored to address unique data characteristics and analysis needs. New forecasting approaches continue to be evaluated in order to improve all aspects of the load forecasting process.

This report documents the models, methods, data and key assumptions employed for energy and demand forecasting for both Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU). Due to differences in the historical data series for the two companies and their recent merger, the energy and demand forecasting process for the 1999-2013 period has maintained existing forecast processes for each utility. For the combined system, the separately estimated demand forecasts are not considered to be strictly additive due to some slight non-coincidence in system peaks. Therefore, a final consolidation process for combined company system demand has been developed and will be discussed in this report. The remainder of this section addresses at a summary level the models, methods, data, and key assumptions in developing the load forecast for the 1999 Integrated Resource Plan (IRP).

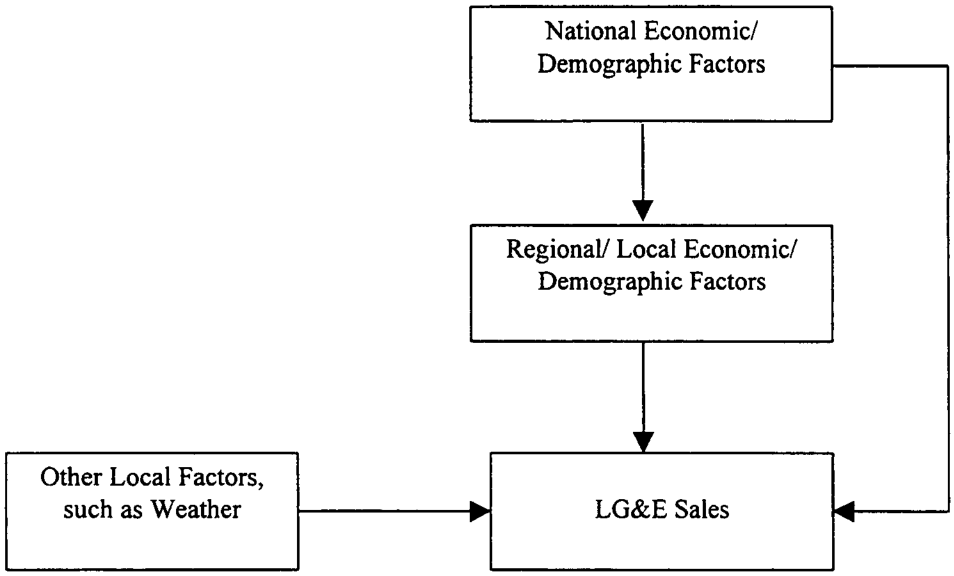
Louisville Gas and Electric

An econometric forecasting approach was used to develop the forecast to satisfy two critical forecasting requirements. First, the econometric approach combines the economic and demographic factors that determine sales in a rational manner. The national, regional, and local drivers for LG&E sales were organized in a top-down or satellite approach, as shown in Figure 5.(2)-1. This means that national economic conditions affect regional and local economic circumstances. Local economic and demographic conditions, in turn, influence LG&E sales. This widely accepted approach in the forecasting community was used to produce a base case forecast and optimistic and pessimistic growth scenarios needed in the sensitivity analyses of the various resource acquisition plans being studied.

Second, this approach quantified cause and effect relationships between electric sales and peak demand, and the national and local factors that influence sales and peak demand. The Consumer price index, national income deflator, and industrial productivity changes were the national factors. Local influences were employment, population, households, personal income, weather, and the price of electricity. Weather data was received from the National Climatic Data Center (NCDC), a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. The electric price forecast was determined internally.

The econometric models used to produce the forecast passed two critical tests. First, the explanatory variables of the models were theoretically appropriate and have been widely used in electric utility forecasting. Second, inclusion of those explanatory variables led to statistically significant models and produced acceptable model simulation results. In other words, the models were proven theoretically and empirically robust to explain the behavior of historic LG&E customer and sales data.

Figure 5.(2)-1
Organization of Economic and Demographic Factors Influencing LG&E Sales



Once econometric relationships were estimated, the electric sales and peak demand forecasts were produced by standard econometric procedures. First, forecasts of explanatory variables were obtained. Forecasts of national economic variables for the baseline, optimistic, and pessimistic cases were purchased from WEFA Group. Regional economic and demographic forecasts for the baseline, optimistic, and pessimistic cases were prepared by the University of Louisville and by the University of Kentucky's Center for Business and Economic Research (UK/CBER). A short-term economic outlook for the Louisville MSA was also provided by Regional Financial Associates, Inc (RFA). The regional forecasts were constructed so that they were consistent with, and driven by, the national economic forecasts. Finally, LG&E's electric sales and peak demand forecasts were produced by feeding the forecast driver values into and solving the econometric equations. Separate models were developed for energy sales and peak demand. The independently produced sales forecasts and peak demand forecasts were jointly evaluated for reasonableness by reviewing the load factors calculated from the forecasts. A more detailed description of the forecasting models, methods, and data used to develop the forecasts are contained in Section 7 of this report and in Technical Appendix 1 of Volume II.

Kentucky Utilities

The KU Energy Forecast addresses three basic jurisdictional groups: Kentucky-Retail, Virginia-Retail, and Wholesale sales to eleven municipally-owned utilities in Kentucky, Berea College (a privately owned utility serving the city of Berea), and Pitcairn, Pennsylvania. The distribution of predicted sales by jurisdiction for 1999 is 85.1% Kentucky-Retail, 4.8% Virginia-Retail, and 10.1% Wholesale.

The KU Energy forecast as generated within each group is disaggregated by classes in order to address the unique characteristics identifiable within each class. Typical classes include Residential, Commercial, and Industrial sales. The number of customers as well as Gigawatt-Hours (GWH) are forecasted, with some models based on a Kilowatt-Hours (KWH) per customer forecast. Econometric and end-use modeling techniques were used with minimal use of trending.

The use of econometric forecasting by KU is appropriate as it provides a theoretically sound basis for testing the relevance of various economic and demographic factors for significance as explanatory variables of electricity sales, and provides the framework to utilize forecasts of significant factors to generate forecasts of electricity sales. In addition to a baseline forecast, optimistic and pessimistic scenarios are developed to support sensitivity analysis of the various resource acquisition plans being studied.

To insure consistency within the planning function, LG&E and KU both utilize the national economic forecast data from WEFA Group Inc., a well-respected and nationally recognized economic consulting firm used by many utilities. Growth prospects in the national economy are important to the projection of energy usage due to a close linkage between the national and the regional economic activities and the use of energy.

For KU, WEFA generated national forecast data is fed to the University of Kentucky Center for Business and Economic Research's (UK/CBER) State Econometric Model. The UK State Econometric Model produces forecasts of value-added output, employment, income and population. The model has been operated by the Center for Economic Research since 1995.

State forecasted data from the State Econometric Model for value-added output, employment, income and population as well as national forecasts for total employment and selected industrial production indices are fed to the Kentucky Utilities Service Territory Economic Model (KUSTEM), which is also a product of UK/CBER. KUSTEM is an employment-driven model in which forecasts of sector level value-added output, employment, income, population and households are generated for five KU regions and then summed to create system-level class forecast drivers.

Coal mining is an important industry in the KU service territory. A coal production forecast for East and West Kentucky is obtained from Resource Data International (RDI). The forecast is disaggregated by producing mine, allowing the forecast to reflect at the mine level the assumed impacts of Phase I of the Clean Air Act Amendment of 1990 and Phase II, which goes into effect in 2000.

Weather and electric prices are local variables that are included in the forecast development process where appropriate. Weather data is received from the National Climatic

Data Center (NCDC), a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. The electric price forecast is determined internally.

KU also relies on company-collected report and survey data as inputs to the forecasting process. Such data enables KU to estimate the percentage of new residential customers choosing the Full Electric Residential Service (FERS) rate by type of housing, the availability of gas at new hookups, the mix of residential housing types on the KU system, the approximate saturation level of various appliances, and the sales history by key Standard Industrial Classification (SIC) codes.

The KU Peak Demand forecast is calculated from the class-level energy forecast, actual and assumed data on class and customer-level load shapes, impacts on system load associated with KU's Curtailable Service Rider (CSR) rate, weather data and losses. The energy, load shape and weather information is combined and customer and class-level demand forecasts are developed using the Hourly Electric Load Model (HELM) developed by EPRI. The annual class demand profiles are summed within HELM to create the system demand forecast.

More detail on the models, methods, data and key assumptions for KU's energy and demand forecast is provided in Section 7 of this report and in Technical Appendix 2 of Volume II.

Combined Company

The energy forecasts of the individual operating companies are combined through a simple additive process. The peak demand forecast for the combined company is developed by appending the system-level load forecast for LG&E to the hourly load forecast for the KU system within the HELM model. Due to some slight non-coincidence, the individual company peaks are not additive in arriving at the combined demand forecast. The application of the HELM methodology allows for the separate company load forecasts to be properly aligned.

Resource Assessment and Acquisition Plan

In the planning decision-making process, the economics and practicality of supply-side and demand-side options are carefully examined to develop the Integrated Resource Plan for meeting customer's expected needs. If, upon review, an alternative plan shows economic viability, a capacity expansion computer program is used to evaluate its operational characteristics and economics.

The Companies use New Energy Associates' PROSCREEN II program for resource expansion studies. PROSCREEN II contains several modules that can be executed in various ways to evaluate system resource expansion alternatives.

Two key assumptions and uncertainties associated with the development of the Companies' IRP are forecasted fuel prices and forecasted customer load requirements. As a part of the detailed resource assessment using PROSCREEN II, sensitivity analyses were conducted on these variables.

Currently, three types of fuel are simulated in the resource optimization analysis: coal, oil, and (natural) gas. A major change in future oil, gas or coal prices can have a significant impact on the selection of new units and on the operation of existing units. Therefore, three fuel forecasts (Base, High, Low) and associated probabilities of occurrence are developed and analyzed as part of the development of the plan.

The load forecast (demand and energy forecast) is another significant factor influencing the Companies' resource plan. Each resource option is selected for optimal performance at specific levels of utilization. Alternative load growth scenarios also may have a significant impact on the selection of an optimal technology, type and size. Three load forecasts and their associated probabilities of occurrence are developed. The three forecasts show an expected system load growth case, a case where system load growth exceeds expected growth, and a case in which system load growth is less than expected. The three load forecasts were analyzed as part of the integrated resource plan development.

5.(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts;

Combined Company

On a combined basis, actual internal sales for Louisville Gas and Electric and Kentucky Utilities have risen from 25,415 GWH in 1994 to 28,666 GWH in 1998, an average annual growth rate of 3.1 percent. Generation has grown from 26,897 GWH to 30,278 GWH, an average annual growth rate of 3.0 percent. Demand has grown from a combined 5,346 MW in 1994 to 5,986 MW in 1998, an average annual growth rate of 2.9 percent. Table 5.(3)-1 presents the historic data.

Table 5.(3)-1
Historic Load Data for the Combined Companies

	1994	1998
Sales (GWH)	25,415	28,666
Generation (GWH)	26,897	30,278
Demand (MW)	5,346	5,986

Looking forward from 1999, sales are expected to grow from a predicted combined value of 29,358 GWH in 1999 to 33,083 GWH in 2004, averaging 2.4 percent compound annual growth. By 2013, combined sales are predicted to reach 38,906 GWH, with growth averaging 1.9 percent per year over the forecast horizon. Table 5.(3)–2 presents the combined company forecast for customers, energy sales, and generation.

Table 5.(3)-3 presents the combined company forecast for summer and winter demands. The combined company demand forecast incorporates the expected native load demand of both

Table 5.(3)-2
COMBINED COMPANY CUSTOMERS, SALES & GENERATION FORECAST

Year	Combined Company Customers	% Growth in Customers	Combined Company Energy Forecast* (GWH)	% Growth in Energy Sales	Combined Company Generation Forecast* (GWH)	% Growth in Generation
1999	837,867	1.1%	29,358	2.3%**	31,057	2.5%**
2000	850,301	1.4%	30,173	2.8%	31,979	3.0%
2001	862,582	1.4%	31,014	2.8%	32,812	2.6%
2002	874,853	1.4%	31,734	2.3%	33,577	2.3%
2003	887,372	1.4%	32,379	2.0%	34,258	2.0%
2004	899,444	1.4%	33,083	2.2%	35,063	2.4%
2005	907,425	.9%	33,669	1.8%	35,623	1.6%
2006	917,084	1.1%	34,292	1.9%	36,282	1.9%
2007	926,274	1.0%	34,947	1.9%	36,974	1.9%
2008	935,251	1.0%	35,600	1.9%	37,735	2.1%
2009	944,097	1.0%	36,271	1.8%	38,375	1.7%
2010	952,877	.9%	36,955	1.9%	39,099	1.9%
2011	961,110	.9%	37,591	1.7%	39,774	1.7%
2012	969,236	.9%	38,245	1.7%	40,536	1.9%
2013	977,212	.8%	38,906	1.7%	41,065	1.3%

* Prior to consideration of KU Curtailable Service Rider sales reductions.
** Based on 1998 combined company normalized sales of 28,702 GWH and normalized generation of 30,310 GWH.

companies, although the individual operating company peak forecasts are not strictly additive due to some slight non-coincidence in system peaks. Combined company native demand is predicted to grow from 6,350 MW in 1999 to 7,127 MW in 2004, a growth of 777 MW with an average annual growth rate of 2.3 percent. By 2013, combined company demand reaches 8,397 MW, a growth of 2,047 MW with an average annual growth rate of 1.9 percent per year over the forecast horizon.

Table 5.(3)-3
COMBINED COMPANY SEASONAL DEMAND FORECASTS*

Year	Combined Company Summer Peak Demand (MW)	Percent Growth	Year	Combined Company Winter Peak Demand	Percent Growth
1999	6,350	2.9%**	1998/99	5,282	1.6%**
2000	6,531	2.9%	1999/00	5,415	2.5%
2001	6,665	2.1%	2000/01	5,527	2.1%
2002	6,805	2.1%	2001/02	5,654	2.3%
2003	6,952	2.2%	2002/03	5,783	2.3%
2004	7,127	2.6%	2003/04	5,935	2.7%
2005	7,270	2.0%	2004/05	6,033	2.3%
2006	7,416	2.0%	2005/06	6,158	1.7%
2007	7,547	1.8%	2006/07	6,260	1.7%
2008	7,672	1.7%	2007/08	6,382	2.0%
2009	7,819	1.9%	2008/09	6,514	2.1%
2010	7,986	2.2%	2009/10	6,650	2.1%
2011	8,138	1.9%	2010/11	6,744	1.4%
2012	8,275	1.7%	2011/12	6,871	1.9%
2013	8,397	1.5%	2012/13	6,966	1.4%

* Before adjustment for KU curtailable load or LG&E interruptible load

** Based on an estimated normalized 1998 combined summer peak of 6,131 MW +19 MW for LG&E Interruptible adjustment + 21 MW for KU CSR adjustment. Winter growth rate based on estimated 1997/97 normalized combined peak of 5,198 MW.

Louisville Gas & Electric

A continuous but slower rate of growth is expected for the LG&E service area economy in 1999 and 2000. UPS has just completed a major hiring and Phillip Morris has been making significant cuts, with plans to shut down completely by the end of 2000. GE has recently closed their range unit in Louisville and is considering moving the refrigerator line to Mexico. This unfavorable chain of events will lead to an overall slowdown in the economy and bring job growth below the national rate. However, continuous expansion of Louisville's transportation and service industries will allow the local economy to return to healthy growth by 2001. Over the next few years, Sykes Health Plan Services Inc. will invest $80 million in a new headquarters campus and hire 2,900 new workers. Providian Financial Corp. will hire more than 1,000 workers for a new service center. Gross Metro Product (GMP) grew 3.8 percent in 1998, the best performance since 1994. Projected annual growth rates for GMP in 1999 and 2000 are 2.3 percent and 1.6 percent respectively. The GMP growth rate will bounce back to 3.0 percent in 2001 and will be stabilized at the 2.1 – 2.3 percent level from 2002 to 2004.

As presented in Section B of Technical Appendix 1 in Volume II, the economic outlook for the LG&E service area suggests moderate growth both in the near term and in the long term. Near-term employment and real per capita personal income are expected to grow at average annual rates of 0.8 and 2.1 percent, respectively, between 1999 and 2004. Reflecting future fertility rates and inter-regional migration patterns, population is expected to grow at a 0.5 percent average annual rate for the period 1999-2004.

The long-term regional outlook depicts a stable but slightly lower rate of economic growth. There has been a continuous change in employment mix between the manufacturing and service sectors. The traditionally higher paying manufacturing sector gradually contracts, while the lower paying service sector grows. Over the 1994–1998 historic period, LG&E's weather-normalized retail electric energy sales grew from 9,992 GWH to 10,911 GWH at an average annual growth rate of 2.2 percent. The LG&E sales forecast is summarized in Table 5.(3)-4, and reflects the near and long-term economic and demographic prospects for the service area.

Table 5.(3)-4
LG&E TOTAL CUSTOMERS, SALES & GENERATION FORECAST

Year	Customers	Percent Growth in Customers	Energy Sales (GWH)	Percent Growth in Energy	Generation (GWH)	Percent Growth in Generation
1999	360,227	1.3%	11,110	1.8%*	11,729	2.3%*
2000	364,339	1.1%	11,349	2.2%	11,982	2.2%
2001	368,302	1.1%	11,742	3.5%	12,396	3.5%
2002	372,344	1.1%	11,992	2.1%	12,661	2.1%
2003	376,452	1.1%	12,168	1.5%	12,846	1.5%
2004	380,569	1.1%	12,368	1.6%	13,057	1.6%
2005	384,716	1.1%	12,578	1.7%	13,279	1.7%
2006	388,870	1.1%	12,797	1.7%	13,510	1.7%
2007	392,876	1.0%	13,015	1.7%	13,740	1.7%
2008	396,892	1.0%	13,235	1.7%	13,972	1.7%
2009	400,868	1.0%	13,468	1.8%	14,218	1.8%
2010	404,806	1.0%	13,697	1.7%	14,460	1.7%
2011	408,664	1.0%	13,931	1.7%	14,707	1.7%
2012	412,453	1.0%	14,161	1.7%	14,950	1.7%
2013	416,161	1.0%	14,388	1.6%	15,190	1.6%

* Projected annual growth rates for energy sales and generation in 1999 were calculated from the weather-normalized actual energy sales and generation in 1998. The weather-normalized actual sales and generation in 1998 were 10,911 GWH and 11,461 GWH, respectively.

For the five year forecast horizon through 2004, retail electric sales are projected to grow at an average annual rate of 2.2 percent. Industrial sales are expected to grow at an annual average rate of 1.1 percent for the same period. Residential, general service and large commercial sales are expected to grow at a rate of 1.8 percent, 1.9 percent and 4.9 percent per year, respectively. The large increase in large commercial sales is mainly due to a series of expansions of the United Parcel Service (UPS) facilities scheduled in 2000-2002. Annual peak demand is anticipated to grow at an annual average rate of 2.1 percent for the five-year period through 2004. Table 5.(3)-5 presents the five-year electricity sales forecast for LG&E by class.

Table 5.(3) -5
LG&E RETAIL ELECTRIC SALES FORECAST BY CLASS
1999-2004

	1999	2000	2004	Annual GR
TOTAL	11,110	11,349	12,367	2.2%
RESIDENTIAL	3,599	3,670	3,928	1.8%
GENERAL SERVICE	1,177	1,202	1,295	1.9%
LARGE COMMERCIAL	2,024	2,120	2,567	4.9%
LARGE POWER	3,149	3,162	3,320	1.1%
PUBLIC AUTHORITY	1,091	1,124	1,183	1.6%
STREET LIGHTING	70	71	75	1.4%

Long-term sales expectations reflect the changing industry mix, growing industrial productivity, and a slowdown of population growth. Over the fifteen-year forecast horizon, sales are predicted to grow at an average annual rate of 1.8 percent.

The LG&E peak demand forecast is summarized in Table 5.(3)–6. From 1994 to 1998, LG&E's actual summer peak demand grew from 2,219 MW to 2,427 MW. Although considered a forecast year for purposes of this Integrated Resource Plan, actual summer 1999 peak demand for LG&E was 2,612 MW. The average annual compound growth rate counting 1999 was 3.3 percent and the average annual summer load growth was 79 MW. LG&E's actual winter peak demand was 1,538 MW in the 1993/94 season and was 1,586 MW in the winter of 1997/98. Actual load for the winter of 1998/99, which is considered part of the first forecast year for purposes of the 1999 IRP, was 1,665 MW. The average winter load growth over the 1994-1999 period was 25 MW, or 1.6 percent. These amounts include the impact of load interruptions.

Weather-normalized peak demand is expected to grow from 2,579 MW in 1999 to 2,865 MW in 2004, an increase of 286 MW with an annual average rate of growth of 2.1 percent through 2004. LG&E's weather-normalized winter peak increases from 1,760 MW to 1,910 MW over the same time period, an increase of 150 MW, or 1.6 percent average annual growth. By 2013, LG&E's peak demand is expected to reach 3,392 MW, an increase of 813 MW, and averages 2.0 percent per year growth. Winter demand increases to 2,176 MW by 2013, an increase of 416 MW, and averages 1.4 percent per year growth.

Table 5.(3)- 6
LG&E SUMMER & WINTER PEAK DEMAND FORECASTS (MW)

Year	Summer Peak	Percent Growth	Winter Peak	Percent Growth
1999	2,579	3.7%*	1,760	1.9%*
2000	2,636	2.2%	1,790	1.7%
2001	2,692	2.1%	1,819	1.6%
2002	2,748	2.1%	1,849	1.7%
2003	2,807	2.1%	1,879	1.6%
2004	2,865	2.1%	1,910	1.7%
2005	2,925	2.1%	1,940	1.6%
2006	2,985	2.1%	1,971	1.6%
2007	3,044	2.0%	2,001	1.5%
2008	3,103	1.9%	2,031	1.5%
2009	3,162	1.9%	2,061	1.5%
2010	3,221	1.9%	2,091	1.5%
2011	3,279	1.8%	2,120	1.4%
2012	3,336	1.8%	2,148	1.3%
2013	3,392	1.7%	2,176	1.3%

* For consistency, the projected annual growth rates for summer and winter peaks in 1999 were calculated from the weather-normalized actual peaks estimated with no load interruption assumed. The weather-normalized actual peaks with no interruption were estimated to be 2,486 MW for 1998 summer and 1,727 MW for 1997/98 winter. Actual summer 1999 peak was 2,612 MW and winter 98/99 peak was 1,665 MW

Kentucky Utilities

The KU service territory is predicted to continue its recent strong performance relative to the national economy, with growth in industrial output showing particular strength. Value-added output for the territory as estimated by the KUSTEM model is forecast to grow on average by 3.5 percent per year for the next five years. Commercial employment and real total personal income are forecasted to increase at average annual rates of 2.1 percent and 2.7 percent, respectively over the next five years. The rate of population growth in the service territory is forecasted to match population forecasts for the United States over the next five years. This is a strong performance in a state where population growth has often lagged growth rates nationally. Annual population growth is forecast to average 0.8 percent over the next five years in the KU service territory and nationally. Due to a gradual decrease in household size, the number of households is forecast to increase by 1.4 percent per year in the KU service territory.

Over the 1994–1998 historic period, KU's native electric energy sales grew from 15,431 GWH to 17,659 GWH at an average annual growth rate of 3.4 percent. The KU Energy Forecast is summarized in Table 5.(3)-7, and reflects the near and long-term economic and demographic prospects for the service area. For the five-year forecast horizon through 2004, Total KU energy sales are predicted to rise at a 2.6 percent average annual rate. The fastest growth is expected in the Kentucky Retail Industrial sector with the Wholesale sector and Kentucky-Retail Residential and Commercial sectors close behind. Table 5.(3)-8 presents the five-year electricity sales forecast for KU by class. Over the fifteen-year forecast horizon, sales are predicted to grow at an average annual rate of 2.1 percent.

Table 5.(3) - 7
KU TOTAL COMPANY CUSTOMER ,SALES, & GENERATION FORECASTS*

Year	Customers	Percent Growth in Customers	Company Energy Forecast (GWH)	Percent Growth in Energy Sales	Company Generation Forecast (GWH)	Percent Growth in Generation
1999	477,640	1.8%	18,244	2.4%**	19,328	2.5%**
2000	485,962	1.7%	18,825	3.2%	19,997	3.5%
2001	494,280	1.7%	19,273	2.4%	20,416	2.1%
2002	502,509	1.7%	19,743	2.4%	20,916	2.5%
2003	510,920	1.7%	20,212	2.4%	21,412	2.4%
2004	518,875	1.6%	20,716	2.5%	22,006	2.8%
2005	522,709	.7%	21,092	1.8%	22,344	1.5%
2006	528,214	1.1%	21,496	1.9%	22,772	1.9%
2007	533,398	1.0%	21,931	2.0%	23,234	2.0%
2008	538,359	.9%	22,366	2.0%	23,763	2.3%
2009	543,229	.9%	22,804	2.0%	24,157	1.7%
2010	548,071	.9%	23,259	2.0%	24,639	2.0%
2011	552,446	.8%	23,661	1.7%	25,067	1.7%
2012	556,783	.8%	24,085	1.9%	25,586	2.1%
2013	561,051	.8%	24,519	1.8%	25,875	1.5%

* Before adjustment for energy loss due to the Curtailable Service Rider

** Based on normalized 1998 billed sales of 17,811 GWH and normalized generation of 18,859 GWH.

Table 5.(3) - 8
KU ELECTRIC SALES FORECAST BY CLASS
1999-2004

	1999	2000	2004	ANNUAL G.R
TOTAL	18,244	18,825	20,716	2.6%
RESIDENTIAL	5,078	5,191	5,665	2.2%
COMMERCIAL	4,925	5,119	5,679	2.9%
INDUSTRIAL	4,923	5,153	5,699	3.0%
MINE POWER	502	475	479	-0.9%
VIRGINIA	879	898	974	2.1%
WHOLESALE	1,836	1,888	2,114	2.9%

The KU peak demand forecast is summarized in Table 5.(3)–9. From 1994 to 1998, KU's actual summer peak demand grew from 3,127 MW to 3,559 MW or 432 MW, averaging 108 MW of growth per year. Although considered a forecast year for purposes of this Integrated Resource Plan, actual summer 1999 peak demand for KU was 3,764 MW. The compound average annual growth rate counting 1999 was 3.8 percent. KU's actual winter peak demand was 3,092 MW in the 1993/94 season and was 2,900 MW in the winter of 1997/98. However, load for the winter of 1998/99, which is considered part of the first forecast year for purposes of the 1999 IRP, rebounded to 3,453 MW, or 361 MW of growth over the 1994-1999 period. The average winter load growth was 72 MW, or 2.2 percent per year. These amounts include the impact of curtailments.

The KU forecast of native peak demand increases from 3,804 MW in 1999 to 4,300 MW in 2004, an increase of 496 MW with an average annual rate of growth of 2.5 percent. The winter season demand forecast increases from 3,586 MW to 4,091 MW, an increase of 505 MW with an average annual growth of 2.7 percent per year. For the 1999 - 2013 period, KU's peak demand forecast increases at an average annual rate of 1.9 percent average annual growth rate, and the winter season demand forecast increases at an average annual rate of 2.0 percent. From 1999 to 2013, peak demand increases by 1,244 MW. Over the forecast period KU is predicted to remain a summer peaking system, although the difference in the summer and winter peaks narrows over the forecast period.

Table 5.(3) - 9
1999-2013 KU Seasonal Peak Demand (MW)*

Year	Summer Peak	Percent Growth	Year	Winter Peak	Percent Growth
1999	3,804	3.8%**	1998/99	3,586	2.2%
2000	3,930	3.3%	1999/00	3,690	2.9%
2001	4,009	2.0%	2000/01	3,771	2.2%
2002	4,092	2.1%	2001/02	3,868	2.6%
2003	4,180	2.2%	2002/03	3,967	2.6%
2004	4,300	2.9%	2003/04	4,091	3.1%
2005	4,384	2.0%	2004/05	4,160	1.7%
2006	4,471	2.0%	2005/06	4,254	2.3%
2007	4,543	1.6%	2006/07	4,324	1.7%
2008	4,609	1.5%	2007/08	4,417	2.2%
2009	4,698	1.9%	2008/09	4,521	2.4%
2010	4,807	2.3%	2009/10	4,628	2.4%
2011	4,903	2.0%	2010/11	4,692	1.4%
2012	4,983	1.6%	2011/12	4,789	2.1%
2013	5,048	1.3%	2012/13	4,856	1.4%

* Native estimated load prior to adjustment for the Curtailable Service Rider
** Based on normalized peak of 3,664 MW. Actual 1999 summer peak was 3,764 MW and actual 98/99 winter peak was 3,453 MW

Key Assumptions

The following key economic and demographic assumptions were made for the primary drivers of LG&E's Energy and Demand Forecast:

- LG&E service area population will grow from 741,318 in 1999 to 797,321 in 2013, at an average annual growth rate of 0.5%.
- Number of persons per residential customer count will decrease from 2.32 persons in 1999 to 2.17 persons in 2013.

- Real per capita personal income in the Louisville SMA will increase from $24,212 in 1999 to $31,593 in 2013, at an average annual growth rate of 1.9%.
- Real price of electricity will become lower at an average annual rate of [redacted]
- Trade and service industry employment in the Louisville MSA will grow at an annual rate of 1.1%, while manufacturing employment will slightly decline for the next fifteen-year period.
- Future climate is reflected by the weather values averaged for the most recent twenty-year period.
- The saturation rate of residential air conditioners, combined for window units and central units, will increase from 94.9% in 1999 to 99.0% in 2013.

The following key economic and demographic assumptions were made for the primary drivers of KU's Energy and Demand Forecast:

- Annual U.S. Real Gross Domestic Product growth will average 2.0 percent over the next five years and 1.9 percent over the next fifteen years.
- Households in KU-served counties are predicted to increase at a 1.8 percent annual average rate over the next five years, and 1.3 percent over the next fifteen years
- Over the next five years, it is predicted that approximately 45 percent of all new households in KU-served counties will locate on KU territory. From 2000 to 2010, the percentage slips to approximately 42 percent.
- Residential customers are predicted to increase at a 1.7 percent annual rate for the next five years, and at a 1.1 percent annual rate over the next fifteen years.

- The nominal retail price of electricity is predicted to rise at an average annual rate of [redacted] percent over the next fifteen years due to increases in generation fuel costs. Discounted for the general rate of expected future inflation, real price is expected to decrease.
- The nominal residential price of gas is predicted to rise at an average annual rate of [redacted] percent over the next five years and [redacted] percent over the next fifteen years.
- KU service territory industrial output is predicted to increase at 3.7 percent annual rate for both the next five years and 3.5 percent for the next fifteen years.
- KU service territory commercial employment is predicted to increase at an average annual rate of 1.6 percent for the next five years and 1.9 percent over fifteen years.
- East Kentucky coal production is predicted to rise at a 0.6 percent average annual rate for both the next five and fifteen year periods. West Kentucky coal production is predicted to decline at an average annual rate of 0.1 percent for the next five years and increase at an average annual rate of 0.7 percent for the next fifteen years.
- Appliance efficiency standards as set by the National Energy Policy Act of 1992 are reflected in the forecast.

5.(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, non-utility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities;

Summary of Planned Resource Acquisitions

The Companies' resource planning process considers the economics and practicality of available options to meet customer needs at the lowest practical cost. A study was completed to determine an optimal resource plan. The base case series (base assumptions) from this study indicates that a 12% target reserve margin represents the greatest system reliability under the given set of assumptions. This study further indicated that an optimal target reserve margin in the range of 11% to 14% would provide an adequate and reliable system to meet customers' demand. In the development of the optimal integrated resource plan, the Companies used a reserve margin target of 12% to represent a base case scenario. The plan resulting from the Companies' optimal integrated resource plan analysis is shown below in Table 5.(4) and is detailed in a report titled, *Optimal Integrated Resource Plan Analysis* (October 1999) in Volume III, Technical Appendix. The in-service years for the units shown assume the Companies' Base Load Forecast, and do not account for the fact that combustion turbines may not be available from the major manufacturers for in-service by the years listed.

The Companies internally pursue measures to maintain a reliable source of power. For 1999, summer contracts were in place to purchase 474 MW of peaking power in July and 200 MW in August, in addition to the early August 1999 commissioning of the E. W. Brown Units 6 and 7 totaling 328 MW. Additional capacity will be required to reliably meet customer demands for the summer of 2000. While the Companies are pursuing additional capacity for the summer of 2000, including inlet air cooling at the E. W. Brown Units 8-11, it is likely that additional power must be purchased.

Table 5.(4)
Recommended Integrated Resource Plan

Year	Resource
1999	
2000	300 MW of Purchased Power
2001	160 MW Brown CT Unit 5 160 MW Greenfield CT Unit 1 160 MW Greenfield CT Unit 2 22.1 MW Direct Load Control program
2002	160 MW Greenfield CT Unit 3 22.1 MW Direct Load Control program 20.6 MW Standby Generation program 23.2 MW Efficient Lighting program
2003	22.1 MW Direct Load Control program 20.6 MW Standby Generation program 23.2 MW Efficient Lighting program
2004	160 MW Greenfield CT Unit 4 22.1 MW Direct Load Control program 20.6 MW Standby Generation program
2005	160 MW Greenfield CT Unit 5 22.1 MW Direct Load Control program
2006	160 MW Greenfield CT Unit 6
2007	160 MW Greenfield CT Unit 7
2008	160 MW Greenfield CT Unit 8
2009	160 MW Greenfield CT Unit 9
2010	160 MW Greenfield CT Unit 10
2011	160 MW Combined Cycle CT Phase 1
2012	160 MW Combined Cycle CT Phase 2
2013	150 MW Combined Cycle CT Phase 3

The technological status, construction aspects, operating costs, and environmental features of various generation plant construction options were reviewed. After screening many technologies, six generation plant construction options and one IPP purchase option were recommended for evaluation using resource planning computer models. Along with these supply-side options, three DSM programs were included in the integrated analysis. The optimal integrated resource plan recommends the implementation of all phases of each of the three DSM programs except one phase of the Standby Generation program, the completion of the E. W. Brown CT site with an additional 160 MW combustion turbine, the development of a Greenfield CT site, and the installation of a phased constructed combined cycle combustion turbine.

Efficiency Improvements

The plan described in Table 5.(4) does not explicitly call for generation efficiency improvements. However, the Companies continue to evaluate economic improvements to their generation fleet. Maintenance schedules are coordinated across the entire generation system such that the outages will have the least economic impact to the customers and the Companies. Additional details are provided in Section 8.(2)(a).

Demand Side Management

The plan described in Table 5.(4) includes the implementation of five phases of Direct Load Control (DLC) beginning in 2001, three phases of Standby Generation beginning in 2002, and two phases of Efficient Lighting beginning in 2002.

The DLC Program is an aggregated program that targets the DLC of residential and commercial central air conditioning units and residential pool pumps of both KU and LG&E

customers. It is designed to provide customers with an incentive to allow the Companies to interrupt service to their central air conditioners and/or pool pumps at those peak demand periods when the Companies need additional resources to meet customer demand.

The Standby Generation is an aggregated program that targets commercial and industrial customers of both KU and LG&E who own backup generating units at their facilities. The industrial and commercial customers would receive a bill credit in return for allowing the Companies to request the utilization of these backup generators during peak periods when the Companies need additional resources to meet customer demand.

The Efficient Lighting is an aggregated program that targets residential customers with outdoor lighting, commercial and industrial lighting customers, and residential customers willing to install water heater blankets. Customers would be encouraged to install efficient lighting equipment and to install water heater blankets.

As with many DSM programs there are uncertainties surrounding implementation of the programs. The expected marketability and penetration of a program is difficult to predict until the program actually begins or experience is gained through a pilot program. The expected level of load reduction can also change due to a number of factors, e.g., efficiency of the air conditioners, or connected load of the standby generator.

The three DSM programs may be conducted as pilot programs until such time that they prove to be acceptable by the customers and provide the peak reduction benefits to the Companies.

Additional detail on the three DSM alternatives in the plan is contained in the report titled *Screening of Demand-Side Management (DSM) Options* (September 1999) contained in Volume III, Technical Appendix.

Non-Utility Generation

The plan described in Table 5.(4) does not explicitly include any non-utility generation. However, on occasion, the Companies receive inquiries from Independent Power Producers (IPPs). The IPPs typically have an interest in projects based on combined-cycle or base-load technology and not on simple-cycle technology. The Companies have evaluated and will continue to evaluate all bid proposals received with the goal of determining least cost generation resources for meeting the needs of customers.

Recently, Dynegy Inc. announced plans to build a 324 MW gas-fired merchant plant in Buckner, Kentucky, and a 500 MW gas-fired merchant plant in Lawrence County, Kentucky. Enron Corp. has also announced plans to build a 500 MW gas-fired merchant plant in Calvert City, Kentucky and a 500 MW gas-fired merchant plant in Knox County, Indiana. Location of Exempt Wholesale Generators (EWGs) near or within the Companies' service territory is expected to continue as the deregulated wholesale power marketplace evolves. The Companies anticipate receiving offers from EWG's to supply capacity needs and thus will include EWG's, including Dynegy and Enron, in any Requests for Proposals for purchased power that may be issued by the Companies in the future.

New Power Plants

The technology, construction aspects, operating costs, and environmental features of various generation construction projects were reviewed. After screening many technologies, six generation plant construction options and one IPP Hydro project were evaluated using expansion planning computer analysis.

The plan described in Table 5.(4) calls for a significant number of new power plants. The plan calls for three new 160 MW CTs in 2001, one 160 MW CT in 2002, and another 160 MW CT in every year from 2004 through 2010 inclusive. Installation of a phased-constructed combined cycle CT facility is recommended from 2011 through 2013. Clearly, new power plants are the most significant component of the 15-year least-cost plan; the plan as presented does not account for the fact that combustion turbines may not be available by the in-service dates listed.

Transmission Improvements

The Companies routinely identify transmission construction projects and upgrades required for maintaining the adequacy of its transmission system to meet projected customer demands. The construction projects currently identified are included in Volume III, Technical Appendix under the section labeled Transmission Projects.

Bulk Power Purchase and Sales and Interchange

The plan described in Table 5.(4) includes 300 MW of Purchased Power for 2000. The Companies are pursuing additional capacity for the summer of 2000, including inlet air cooling at the E. W. Brown Units 8-11. However, it is likely that no new generation resources will be available for completion by summer 2000. Thus, the Companies will most likely purchase an additional 300 MW.

The Companies have purchase power arrangements with Owensboro Municipal Utilities (OMU) and Electric Energy, Inc. (EEInc) to provide additional sources of capacity. Under the OMU agreement, the Companies purchase (on an economic basis) the output not needed by OMU's system from two coal-fired, base-load units (combined capacity of approximately 400 megawatts). For 1999, the Companies expect to receive 199 megawatts of capacity from OMU. For each year after 1999, the expected capacity available to KU is projected to decrease due to the increases in OMU's customer load.

The EEInc purchase agreement permits the Companies to share in the output of six coal-fired, base-load units with combined capacity of approximately 1000 megawatts. In 1988, KU exercised its 20 percent ownership right to a full entitlement of 200 megawatts year-round. The Companies currently schedule the full entitlement of 200 megawatts from EEInc.

5.(5) Steps to be taken during the next three (3) years to implement the plan;

2000 & Beyond Capacity Shortfall

The Companies are currently reviewing alternatives for meeting the identified capacity shortfall for 2000 and beyond. The first consideration at this time is the purchase of 300 MW for 2000; the next immediate consideration is the addition of a 160 MW CT at Brown Unit 5 for 2001. If alternatives to construction of additional capacity are found to be uneconomical for 2001, and a CT becomes available, the Companies will submit an Application to the PSC for appropriate certificates for the installation of Brown CT Unit 5, the seventh simple cycle combustion turbine (CT) at the Companies' E. W. Brown Generation Station site. A seventh combustion turbine at the Brown site would be constructed pursuant to the Prevention of Significant Deterioration Permit (permit to construct an air contaminant source) issued by the Kentucky Division for Air Quality (DAQ) to KU. On the other hand, if economic purchased power alternatives are found, the Companies will negotiate with prospective suppliers to obtain agreements that would defer the need for generation construction.

The Companies are pursuing the installation of an Inlet Air Cooling system for use with the existing E. W. Brown Units 8-11 CTs. The system utilizes ice storage to cool the inlet air of the combustion turbines. This capacity addition was built into the base data as an existing resource enhancement for inclusion in the integrated resource planning analysis.

Demand-Side Management

The three DSM alternatives included in the plan will be subjected to a much more rigorous program design cycle, including pilot programs, which could result in program concepts and program details being changed significantly.

Implementation of the DSM programs in the plan will then require the preparation of a multi-year DSM filing that would include any update in program design, would have the selected programs by customer class, and would include the recovery of the expected cost to administer the programs and the expected lost revenue for all programs. This filing would include a new rate tariff for the Standby Generation programs.

As a final step, a Request For Proposal (RFP) will be developed and issued for an administrator/contractor for each of the programs. Some of the programs may be marketed through LG&E's residential and commercial Energy Audit program, with development of a similar program for industrial customers. Similar programs may be developed for the customer classes of KU. Marketing representatives for the Companies would be trained on the new customer offerings. The Companies would develop a process to track data related to each program.

5.(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

Forecast Uncertainty

For the 1999 IRP, the uncertainty analysis was performed by controlling future values of the most important variables to the forecast. Table 5.(6) shows the variables chosen to produce optimistic and pessimistic growth outlooks for each operating company. The alternative outlooks are documented in Technical Appendices 1 and 2 of Volume II.

Table 5.(6)
UNCERTAINTY ANALYSIS STUDY VARIABLES

LG&E Variables	KU Variables
• Population • Per Capita Personal Income • Employment by Industry • Electricity price by class	• Residential Customers • Service Territory Value Added Output • Commercial Employment • Electric Price

Purchased Power

The availability of purchased power at economical prices could provide an alternative to the construction of generation capacity. However, purchased power prices in the wholesale power market are volatile at this time. The market events of 1998 and 1999 have caused a significant increase in forward contract prices for on-peak power in the summer months. The price spikes that occurred during the summers of 1998 and 1999 also introduced uncertainty regarding the deliverability of purchased power. In 1998, the unprecedented price levels caused several utilities and power marketing entities to default on their power sales obligations. Some degree of uncertainty regarding the availability of purchased power products--particularly call options--exists as well.

The forward prices in the market for purchased power change frequently. Such a change may initiate a corresponding revision to the plan as presented in this resource assessment.

Combustion Turbine Availability

The market events that occurred during the summers of 1998 and 1999 also initiated a tremendous increase in the demand for generating assets, particularly for combustion turbines. The major CT manufacturers are currently faced with a backlog of orders for CTs and for related equipment such as generators and generating step-up transformers (GSUs). The lead time associated with acquiring new CTs is increasing. Most suppliers are indicating that they will not have CTs available for in-service until 2003 or possibly 2004.

The addition of three CTs in 2001 as indicated in the recommended plan found in Table 5.(4) is highly dependent upon the availability of CTs in the marketplace, thus making CT acquisition and plan implementation difficult.

The Companies issued an RFP for CTs to the three major CT suppliers (ABB, GE, and Siemens Westinghouse) on September 27, 1999, and expect to receive more specific information regarding CT availability in the RFP responses. On occasion, a CT may become available if a purchaser cancels a purchase order with a supplier. Used machines also become available from time to time, usually on short notice.

DSM Implementation

The level of peak reduction ultimately reached in any of the DSM programs in this plan may not equal the target values listed in Table 5.(4). Several things could change that may alter the resulting peak reduction of these programs. The peak reduction for each participant could vary compared to the assumptions. The number of customers willing to participate could vary. If the willingness of customers to participate changes significantly, it may be possible to modify the level of incentives and/or the marketing to maintain the expected level of participation.

The DSM alternatives included in the plan might not be implemented as they have been described in this report, because any DSM program will be subjected to a much more rigorous program design cycle, including pilot programs, which could result in program concepts and program details being changed significantly.

SECTION 6-
SIGNIFICANT CHANGES

6. SIGNIFICANT CHANGES

All integrated resource plans shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.

The plans most recently filed are the LG&E 1993 IRP and the KU 1996 IRP. Numerous significant changes have taken place since those filings. The single most comprehensive change is the merger of the parent companies of KU and LG&E. Other changes are initiated in response to the PSC Staff Reports on the previous plans. The major changes in the 1999 IRP from the plans most recently filed are described in the sections that follow.

Merger of KU and LG&E

On May 4, 1998, LG&E's holding company parent, LG&E Energy Corp., and KU's holding company parent, KU Energy Corporation, merged. At that time, KU joined LG&E as a wholly-owned subsidiary of LG&E Energy Corp. As the owners and operators of interconnected electric generation, transmission, and distribution facilities, the Companies achieve economic benefits for their customers through operation as a single interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities. Coordinated planning in this context means that supply-side and demand-side alternatives for meeting the future needs of electric service customers are planned and developed on the basis that the combined KU and LG&E systems constitute an integrated electric system. The resource planning effort is undertaken with the intent of maximizing the reliability, efficiency, and economy of the system as a whole.

The merger has introduced the majority of the significant changes since the plans most recently filed. In this IRP, the Companies developed the resource assessment and acquisition plan on a joint basis. The ultimate resource assessment and acquisition plan is no longer determined on an individual company basis; optimizations are now developed on a combined basis to produce a joint resource plan. Because the plan and most of its components are developed from its initial stages on a joint basis, it is not meaningful to compare most of the specific data in the 1999 IRP to the same data in the previous individual filings.

Several areas of the 1999 IRP differ from previous filings because of the merger. The Companies now use a single set of software tools, analytic methods, assumptions and data to compile the majority of the components of the resource plan. The 1999 IRP combines the best aspects of each individual Company's pre-merger resource planning process into a single integrated resource planning analysis that is well suited for the needs of the Companies on a joint basis.

Specific changes related to the merger are highlighted in the sections that follow, along with other significant changes that apply to particular components of the 1999 IRP.

Resource Assessment and Acquisition Plan

The resource assessment and acquisition plan is developed on the basis that the combined individual KU and LG&E systems constitute an integrated electric system. In general, the plans from the LG&E 1993 IRP and the KU 1996 IRP are similar. Both plans called for simple-cycle combustion turbines as the next physical asset addition, with short-term firm purchases used in several years to supplement system capacity. The 1999 IRP is not different in this regard, but both the CT capacities and the implementation years have changed. The 1999 plan recommends the completion of the E. W. Brown CT site with an additional 160

MW combustion turbine in 2001, the development of a Greenfield CT site with three 160 MW CTs in service by 2002 (and a total of ten 160 MW CTs in service by 2010), and finally the installation of phased constructed combined cycle combustion turbines beginning in 2011.

The 1999 plan is summarized in Section 5 and described in Section 8.(4).

Optimal Integrated Resource Plan Analysis

The optimal integrated resource planning analysis is performed using the PROSCREEN II program. Both companies used this model in their last IRPs. However, the optimization in the 1999 IRP explicitly includes DSM alternatives. DSM options were implicitly evaluated in the optimization by KU in their 1996 IRP.

Load Forecast

Changes in the Energy and Demand Forecast are typically driven by the addition of historic sales data to the model's inputs, changes in the weather, economic and demographic assumptions which drive the forecast, and methodological changes which reflect new methods of modeling the outlook. The following discussion addresses these issues for both operating companies.

Louisville Gas and Electric

As shown in Table 6.(1)(a), the 1999 model forecast for total energy sales is higher than the 1993 model forecast. The difference between those two forecasts is 227 GWH or 2.1 percent for 1999. The increase grows to 845 GWH or 6.9 percent by 2007. The peak demand forecast is increased by 201 MW or 8.5 percent for 1999, and grows to a 436 MW or 16.7 percent increase by 2007.

Since the last IRP, the economic and demographic data used for load forecasting has been updated and revised to reflect the most recent information and outlooks. The increases in energy and demand forecasts originate mainly from revised population projections. The population projections for LG&E's service area used for the 1999 load forecasts were based on the county population projections developed by the Center for Business and Economic Research of the University of Kentucky in May 1999. The new population forecast reflects a significantly higher rate of increase in the local population base than the trend anticipated by the 1993 forecast.

Table 6.(1)-(a)
Comparison of LG&E's 1999 IRP Energy and Demand Forecasts with the 1993 IRP Forecasts

	Total Energy Requirements (GWH)				Annual Peak Demand (MW)			
Year	1999 IRP	Ann. G.R.	1993 IRP	Ann. G.R.	1999 IRP	Ann. G.R.	1993 IRP	Ann. G.R.
1999	11,110	1.8%	10,883	1.7%	2,579	3.7%*	2,378	1.5%
2000	11,349	2.2%	11,051	1.5%	2,636	2.2%	2,413	1.5%
2001	11,742	3.5%	11,221	1.5%	2,692	2.1%	2,443	1.2%
2002	11,992	2.1%	11,387	1.5%	2,748	2.1%	2,472	1.9%
2003	12,168	1.5%	11,559	1.5%	2,807	2.1%	2,501	1.2%
2004	12,368	1.6%	11,727	1.5%	2,865	2.1%	2,528	1.1%
2005	12,578	1.7%	11,879	1.3%	2,925	2.1%	2,555	1.1%
2006	12,797	1.7%	12,023	1.2%	2,985	2.1%	2,581	1.0%
2007	13,015	1.7%	12,170	1.2%	3,044	2.0%	2,608	1.0%

* For consistency, the projected growth rate for annual peak demand in 1999 was calculated from the weather-normalized 1998 actual peak demand estimated with no load interruption assumed. The weather-normalized 1998 actual peak with no interruption was estimated to be 2,486 MW. Actual summer peak in 1999 was 2,612 MW.

Table 6.(1)-(b) illustrates how the population projections for Jefferson and Oldham counties have changed from the projections used in the 1993 IRP. For example, the new forecast for Jefferson county population predicts an increase from 676,942 in 1999 to 690,055 in 2005, while the old forecast had a decrease from 661,464 in 1999 to 654,116 in 2005. In

other words, the revised forecast predicts 35,939 more persons will be living in Jefferson County in 2005. Jefferson and Oldham counties constitute 96 percent of LG&E's electric service area population.

The higher population projections resulted in higher forecasts of energy sales to residential and commercial customers and peak demand. However, the impact of higher population projections on annual peak demand is much higher than on energy sales. This is due to the high summer weather sensitivity and large peak demand responsibility of the residential and commercial classes, which will grow faster than the relatively weather-insensitive industrial class.

Table 6.(1)-(b)
Comparison of LG&E's IRP Population Forecast
with the 1993 IRP Forecast

	Jefferson County Population				Oldham County Population			
Year	1999 IRP	Ann. G.R.	1993 IRP	Ann. G.R.	1999 IRP	Ann. G.R.	1993 IRP	Ann. G.R.
1999	676,942	0.42%	661,464	-0.15%	45,386	2.56%	42,865	2.64%
2000	679,074	0.31%	660,465	-0.15%	46,517	2.49%	43,996	2.64%
2001	680,977	0.28%	659,191	-0.19%	47,662	2.46%	44,842	1.92%
2002	683,129	0.32%	657,918	-0.19%	48,809	2.41%	45,705	1.92%
2003	685,403	0.33%	656,649	-0.19%	50,040	2.52%	46,584	1.92%
2004	687,735	0.34%	655,381	-0.19%	51,314	2.55%	47,481	1.93%
2005	690,055	0.34%	654,116	-0.19%	52,755	2.81%	48,394	1.92%
2006	692,405	0.34%	652,854	-0.19%	54,261	2.85%	49,325	1.92%
2007	694,540	0.31%	651,594	-0.19%	55,777	2.80%	50,274	1.92%

Another main determinant of changes in electric energy usage is weather. Starting with the 1993 IRP, LG&E has been using the most recent twenty-year average weather for energy sales and peak demand forecasting. In the 1999 IRP, the weather values were averaged for the period of 1979-1998, while the 1993 IRP forecasts were based on the average weather values calculated for 1973-1992.

Like the 1993 model, the 1999 energy sales forecasting model was structured as an aggregate econometric/end-use model. The 1999 model is capable of providing separate forecasts and analyses for space-heating, air-conditioning, and base usage by residential and general service customers. The residential space-heating model was further disaggregated to all-electric space-heating usage and non-electric-furnace space-heating usage equations. Detailed explanations regarding the model structures and the estimated equations are presented in Section 7 and in Technical Appendix 1 of Volume II.

Kentucky Utilities

KU's total Energy Forecast for the 1999 IRP is initially lower than the 1996 IRP for 1999 and 2000, but thereafter is higher. By 2004, total energy sales are expected to be 493 GWH (2.4 percent) higher than predicted in the 1996 IRP. The difference is essentially the same for 2010 at 494 GWH. Demands are higher in every year under the 1999 IRP, starting with a 45 MW (1.2 percent) increase in 1999 and rising to a 189 MW (4.6 percent) increase by 2004. By 2010, the increase has leveled off at 184 MW (4.0 percent). Table 6.(1)-(c) compares the energy and demand forecasts for KU from the 1996 IRP with the 1999 IRP forecasts.

Recent sales growth in KU's service territory has been particularly strong in the Industrial and Commercial sectors, driving the upward revision of the forecast, but significant increases have also come from the Residential sector. Virginia's outlook has been slightly increased. Wholesale sales are essentially on track with the 1996 IRP, while sales to the Mine Power sector have fallen significantly below expectations.

In order to forecast electricity sales, assumptions must be made regarding the climate over the forecast horizon. KU assumes a twenty-year rolling average of heating degree days (HDD) and cooling degree days (CDD) as a reasonable representation of the likely weather conditions to be experienced on average over the forecast horizon. Lexington, Kentucky is the primary source of weather data, although KU's geographic diversity leads to the use of Bristol, Virginia and Evansville, Indiana for some portions of the forecast. The forecast in the 1996 IRP used the time period of 1975–1994 for the calculation of normal weather, while the 1999 IRP uses the time period of 1979–1998.

Table 6.(1)-(c)
Comparison of KU's 1999 IRP Energy and Demand Forecasts with the 1996 IRP Forecasts *

	Total Energy Sales (GWH)				Annual Peak Demand (MW)			
Year	1999 IRP	Ann G.R.	1996 IRP	Ann G.R.	1999 IRP	Ann G.R.	1996 IRP	Ann G.R.
1999	18,244	2.4%**	18,472	2.9%	3,804	3.8%**	3,783	2.8%
2000	18,825	3.2%	18,841	2.0%	3,930	3.3%	3,853	1.9%
2001	19,273	2.4%	19,124	1.5%	4,009	2.0%	3,919	1.7%
2002	19,744	2.4%	19,437	1.6%	4,092	2.1%	3,983	1.6%
2003	20,212	2.4%	19,809	2.4%	4,180	2.2%	4,056	1.8%
2004	20,716	2.5%	20,223	2.1%	4,300	2.9%	4,135	2.0%
2005	21,092	1.8%	20,693	2.3%	4,384	2.0%	4,230	2.3%
2006	21,496	1.9%	21,158	2.3%	4,471	2.0%	4,331	2.4%
2007	21,932	2.0%	21,599	2.1%	4,543	1.6%	4,414	1.9%
2008	22,367	2.3%	21,997	1.8%	4,609	1.5%	4,488	1.7%
2009	22,804	1.7%	22,389	1.8%	4,698	1.9%	4,570	1.8%
2010	23,259	2.0%	22,765	1.7%	4,807	2.3%	4,647	1.7%

* Native estimated load prior to adjustment for the Curtailable Service Rider
** Calculated using normalized 1998 billed energy of 17,811 GWH and normalized peak of 3,664 MW. Actual 1999 peak was 3,764 MW, a growth of 5.8 percent.

In the 1996 IRP, KU recognized an existing level of curtailable load of 34.5 MW, and assumed an additional 15.5 MW of CSR load for 1999 and thereafter, for a total CSR load of 50 MW. KU currently estimates that it has 54 MW of CSR load under contract.

Methodologies

KU has implemented several methodological enhancements to its energy forecasting process since the 1996 IRP, including its source of macroeconomic data, regional forecast driver development, the introduction of additional short run models, the incorporation of summary level Wholesale sector models, and additional detail within the HELM demand forecasting model. The following is a brief description of each enhancement.

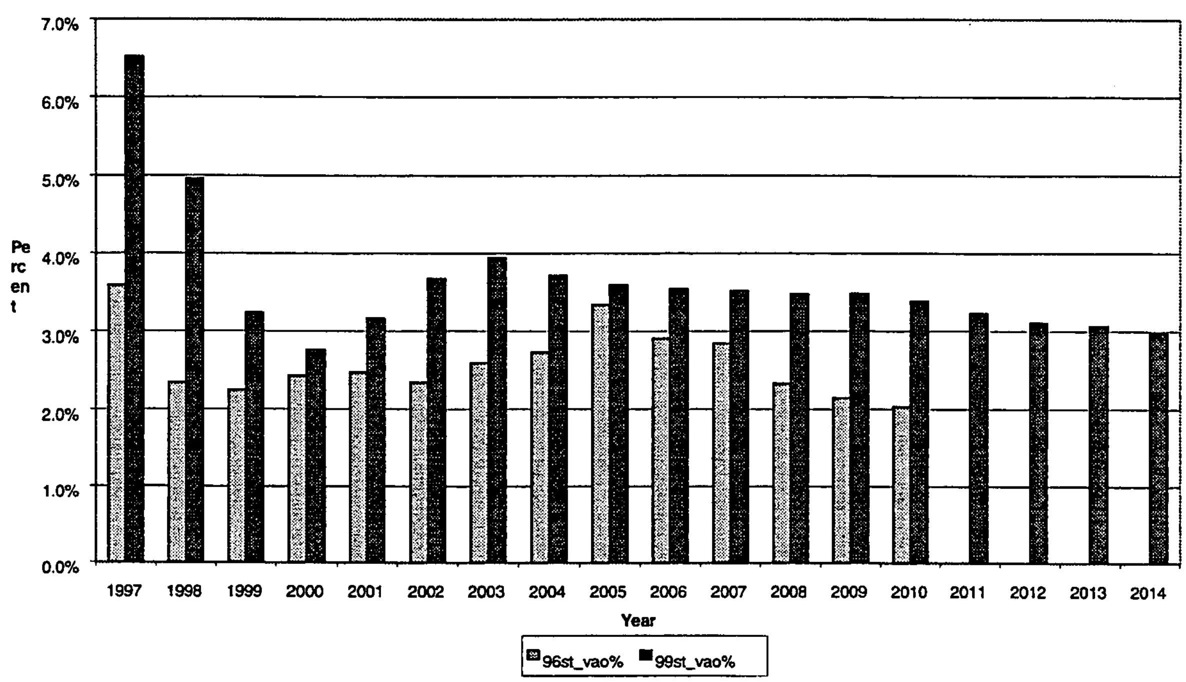
Introduction of KUSTEM

KU has found through comparison of its historical sales growth rates during various periods to that of total Kentucky electricity sales that KU has consistently outperformed the state as a whole. Further, the economy of KU's service territory has appeared to perform better than that of the nation in recent years. These observations led KU to question whether dependence on a state-level economic forecast was the best option for predicting likely growth in its territory. KU also recognizes that the future of strategic marketing in the electric utility industry lies in the knowledge of regional markets not tied to traditional service territory boundaries, and systems supportive of flexible decision analysis.

In response, KU contracted with the Center for Business and Economic Research (CBER) at the University of Kentucky to construct a regional economic and demographic database and modeling system that will enable the Company to become an independent producer of regional and service territory economic forecasts. The model has been named KUSTEM (KU Service Territory Economic Model). KUSTEM utilizes a CBER generated state-level forecast of output in conjunction with five regional models which conform to the local economies served by KU. The five regional models utilize county-level data and the state output forecast by two-digit manufacturing industry to forecast output and employment by two digit industry, commercial employment by two digit sector, personal income, and population/households. Four of the regions correspond to Kentucky and one models the Virginia jurisdiction. Quarterly forecasts are developed for the first three years and annual forecasts thereafter. Attached as Subsection 2 of Technical Appendix 2, Volume II is documentation of the construct of the KUSTEM model.

The use of KUSTEM represents a shift from the methodology employed in the 1996 IRP of using a state-level output and employment forecast from Data Resources International (DRI), adjusted to remove the Louisville Metropolitan Statistical Area. KUSTEM focuses more directly on the growth history and prospects for the economy served by KU, rather than a state-wide perspective as analyzed by the DRI model. Graph 6.1 compares the service territory output forecast for the 1996 IRP versus that for the 1999 IRP. KU's service territory output is

Graph 6.1
KU Service Territory Output
Forecasted Annual Percent Increase



estimated to have increased significantly more rapidly than was expected using the DRI forecast, and a higher rate of growth is expected throughout the forecast period. Additional changes in the forecast associated with the use of KUSTEM are documented in Volume II, Technical Appendix.

Macro-economic Service Vendor

KU now receives its macro-economic forecasts for the national economy from WEFA Group Inc. (WEFA) rather than Data Resources International (DRI). WEFA is a nationally recognized vendor of macro-economic forecasts. KU switched to WEFA as the result of efforts to seek merger synergies between KU and LG&E. LG&E was already using WEFA, so KU's adoption of its forecasts allows for consistency in macro forecast assumptions across service territory forecasts. As KU no longer subscribes to DRI, no comparison has been developed of how the macro-economic forecasts compare between the two vendors.

Kentucky -Retail Commercial and Industrial Short-Run Models

Short-run Kentucky-Retail Commercial and Industrial sector sales models based on monthly data have been developed to go along with existing Residential short-run models. The monthly models use data going back to 1985 to capture near term growth better than a long-term annual model. The models capture the effects of weather on sales more effectively due to the monthly detail and the inclusion of month-specific weather terms. The short-run forecasts are merged with the long run forecast from the annual models.

Municipal Models

Past forecasts have required numerous model runs in the Municipal sector as many of the Municipals provide class-level detail. For the 2000 Energy Forecast cycle, class-level forecasts will still be prepared to provide understanding of the growth prospects of each Municipal. However, for system-level forecasting, KU has migrated to a simplified four-model structure. Models have been constructed for Municipal Transmission sales, Municipal Primary sales, City of Pitcairn, Pennsylvania, and the City of Paris.

HELM Model Enhancement

At the time of the 1996 IRP, KU utilized a combined Commercial/Industrial load shape as one of the class shapes used in developing the demand forecast with the Hourly Electric Load Model (HELM). Since then, KU has over-sampled for its load research effort in its Commercial and Industrial rate classes in order to develop separate Commercial and Industrial load shapes based on rate and SIC code segmentation, rather than just rate code. This method of segmentation is consistent with KU's approach to segmenting energy sales data, allowing forecasted energy sales for each sector to be associated with its own load shape. This approach to segmentation is also more customer-focused than traditional rate-code based segmentation.

Supply-Side Screening

The Companies' Supply-Side Screening analysis for the 1999 IRP is similar to the process that was performed by KU in the development of the KU 1996 IRP. A new version of EPRI's TAG Supply software, which includes an April 1999 database release, was the main source of data for the 1999 IRP. The Companies have incorporated the PSC Staff recommendations on the LG&E 1993 IRP concerning the inclusion of key supporting data and calculations in the filing and the expansion of the "plant cost" for each of the technologies. A significant amount of detail utilized in the supply-side screening analysis can be found in the report titled *Analysis of Supply-Side Technology Alternatives* (August 1999) contained in Volume III, Technical Appendix.

The Companies have also incorporated the PSC Staff recommendation on the KU 1996 IRP concerning the inclusion of environmental cost into the uncertainty analysis. The supply-side screening analysis includes the cost of SO_2 and CO_2 as part of the evaluation. Details of this can be found in the report titled *Analysis of Supply-Side Technology Alternatives* (August 1999) contained in Volume III, Technical Appendix.

Demand-Side Management

The screening of DSM options was performed on a joint-company basis. The DSM objectives in the 1999 IRP are similar to the DSM objectives in previous filings, but the long list of DSM alternatives considered in the screening has changed. As the PSC Staff recommended in its Staff Report on LG&E's 1993 IRP, the Companies expanded the initial DSM option list, even including options that are not applicable to the Companies or that have load shape impacts that are inconsistent with the Companies' load shape objectives. The list used in the 1999 IRP was created by an inter-departmental team; the team examined the diverse base of customers of both KU and LG&E and identified a broad range of DSM alternatives. The quantitative screening process utilizes EPRI's DSManager software, which LG&E used in their 1993 IRP. The COMPASS software package (Comprehensive Market Planning and Analysis System) used by KU in their 1996 IRP for analyzing DSM options was not used in the 1999 IRP.

The Companies have incorporated the PSC Staff recommendations concerning the criteria for qualitative screening, as described in Table DSM-2 in the report titled *Screening of Demand-Side Management (DSM) Options* (September 1999) in Volume III, Technical Appendix.

Another change is the use of the Total Resource Cost Test (TRC) in the quantitative screening of DSM alternatives. The Ratepayer Impact Test (RIM), which was used by LG&E in their 1993 IRP as a quantitative screening criterion, is not used in the 1999 IRP. Both the TRC and the RIM tests are well known measures for screening DSM options. The TRC test, sometimes referred to as the All Ratepayers test, is basically a combination of the RIM test and the participant test. The TRC test provides a measure of the net resource expenditures of a DSM program from the perspective of the utility and its ratepayers as a whole.

Reliability Criteria

In the LG&E 1993 IRP, a minimum reserve margin of 18% was used as the reliability constraint for resource optimization. In the KU 1996 IRP, a reserve margin target of 17.6% was used in the resource assessment and acquisition study. These levels of reserve margins were required for LG&E and KU to independently maintain adequate capacity resources during unexpected generation outages and load projection deviations caused by extreme weather or load growth.

In the current resource assessment and acquisition study, the Companies use a combined target reserve margin of 12%, in the recommended range of 11% to 14%. The combined system can maintain a lower reserve margin because the outage of any one generator is a smaller percentage of the total generation of the combined system, and because diversity exists in loads between the two systems. A discussion of the reliability criteria is found in the report titled *Analysis of Reserve Margin Planning Criteria* (October 1999) in Volume III, Technical Appendix.

Wholesale Power Market

Since 1993, the wholesale power market has undergone tremendous change. The electricity marketplace has developed significantly since wholesale deregulation was initiated by FERC's implementation of the Energy Policy Act of 1992. The market development was furthered in April 1996 by FERC Order 888, which provides for wholesale competition through non-discriminatory open access to transmission services by public utilities. Order 888 resulted in the considerable growth and evolution of the wholesale market, primarily by introducing an extraordinary number of market participants. By 1998, a sizable amount of on-peak power trading was taking place in the forward market. This market evolution allows for nearly immediate price discovery without the use of the traditional Request For Proposal (RFP) for purchased power.

In the last week of June, 1998, unprecedented price volatility occurred in the Mid-west wholesale markets; next-day power prices rose to as high as $7,500/MWh. Similar market conditions occurred for a week in July, 1998. These market events are commonly referred to as the price spikes of 1998. Prices spiked again for several days in July, 1999. These market events had several consequences that still exist at this time; the prices for summer on-peak power remain volatile, and the demand for physical generation assets has increased. These market changes are significant for several reasons.

First, the Companies relied on RFP responses to determine prices for purchased power in the previous IRPs. The Companies expect to continue to issue RFPs for purchased power in the future; however, because purchased power prices are volatile and change often on a daily basis, the RFP is currently not the most effective mechanism for price discovery available to the Companies. Participation in the wholesale power market via telephone conversations and/or electronic communication with market participants--brokers, power marketing entities, and other utilities--has become the primary means of collecting purchased power availability and price data. This is the case because as the wholesale market evolved, the number of market participants and their level of experience increased dramatically. The information technology that supports the marketplace has improved; the speed and extent to which market data is available to market participants has increased. These factors have resulted in an increase in the overall efficiency of the wholesale market, which makes market prices more readily available on a real-time basis.

Second, this report is a snapshot in time of an ongoing resource planning process. The recent price spikes have affected the price and availability of physical generation assets, particularly combustion turbines. The supply-side cost data used in this analysis is the best data available to the Companies at this time. However, the prices for generation assets remain volatile. The availability of physical capacity resources is subject to market trends, much like purchased power prices, and may continue to fluctuate as the wholesale power market continues to mature and evolve.

Renovation of Ohio Falls

LG&E's 1993 Integrated Resource Plan identified the renovation of the Ohio Falls station as a least-cost resource. Since that recommendation, the Companies have initiated an in-depth evaluation of the sustainable long-term generation and modernization needs and opportunities for the facility. This in-depth evaluation is considering several economic options and has been an ongoing process throughout 1999. At the time the Companies' 1999 IRP was being prepared, the evaluation of the Ohio Falls Station was not sufficiently complete to warrant inclusion in the development of the plan. Therefore, the renovation of the Ohio Falls station was not included in the Companies' 1999 IRP. As previously stated, the Companies view the filed plan as a snapshot of an ongoing process. Once the current evaluation of the Ohio Falls Station is complete, it will be incorporated into the Companies' ongoing planning process.

SECTION 7-
LOAD FORECASTS

7. LOAD FORECASTS

As discussed in Section 5.(2), due to differences in the historical data series for the two operating companies and their recent merger, the energy and demand forecasting process ~~for the~~ planning cycle addressed in the 1999 IRP has maintained existing forecast processes for each utility. The following responses to Section 7 requirements are therefore segmented by operating company.

LOUISVILLE GAS AND ELECTRIC COMPANY

7.(1) Specification of Historical and Forecasted Information Requirements by Class

The data submissions in the following subsections were constructed to conform to the specifications provided in Section 7.(1) to the fullest extent possible.

7.(2) Specification of Historical Information Requirements

The data submissions in the following subsections were constructed to conform to the specifications provided in Section 7.(2) to the fullest extent possible.

7.(2)(a) LG&E Average Annual Historic Customers by Class

	1994	1995	1996	1997	1998
Residential Heating	40,119	40,256	40,434	40,644	40,723
Residential Non-Heating	259,353	264,258	267,560	271,308	275,163
Total Residential	299,471	304,514	307,994	311,952	315,886
General Service	33,972	34,311	35,481	36,516	37,046
Large Commercial	2,163	2,201	2,269	2,294	2,312
Large Power	442	464	471	486	485
Street Lighting	3,420	3,518	3,629	3,562	3,562
Total Customers	339,468	345,009	349,844	354,810	359,291

7.(2)(b) LG&E Recorded and Weather-Normalized Annual Energy Sales & Generation and sales by class (GWH)

	1994	1995	1996	1997	1998
SYSTEM SALES:					
Recorded	9,984	10,409	10,562	10,465	11,007
Weather Normalized	9,992	10,296	10,624	10,635	10,911
SYSTEM GENERATION:					
Recorded	10,498	11,018	11,154	11,059	11,552
Weather Normalized	10,507	10,906	11,216	11,229	11,456
SALES BY CLASS:					
Residential Heating	762	754	787	736	703
Residential Non-Heating	2,457	2,628	2,611	2,570	2,877
TOTAL RESIDENTIAL	3,219	3,382	3,398	3,306	3,580
General Service	1,183	1,213	1,244	1,222	1,287
Large Commercial	2,386	2,464	2,537	2,561	2,711
Large Power	3,130	3,283	3,315	3,306	3,359
Street Lighting	66	67	68	69	69
TOTAL SALES	9,984	10,409	10,562	10,465	11,007

Note: Recorded and weather-normalized sales figures shown above are on "as-billed" basis.

7.(2)(c) LG&E Recorded And Weather Normalized Coincident Peak Demands (MW)

	1994	1995	1996	1997	1998
SUMMER					
Recorded	2,219	2,357	2,282	2,414	2,427
Normalized	2,238	2,289	2,316	2,486	2,467
WINTER					
Recorded	1,538	1,593	1,696	1,720	1,586
Normalized	1,490	1,596	1,666	1,714	1,727

7.(2)(d) LG&E Energy Sales and Coincident Peak Demand for Firm, Contractual Committment Customers

	1994	1995	1996	1997	1998
Energy Sales (GWH)	9,984	10,409	10,562	10,465	11,007
Coincident Peak Demand (MW)	2,125	2,284	2,182	2,292	2,304

7.(2)(e) LG&E Energy Sales and Coincident Peak Demand for Interruptible Customers

	1994	1995	1996	1997	1998
Energy Sales (GWH)	1,245	1,361	1,344	1,303	1,278
Coincident Peak Demand (MW)	94	73	100	122	123

Note: The figures shown for energy sales are the total annual energy sales to the interruptible customers. However, significant portions of the interruptible customers' loads are not subject to interruption and the total number of interrupted hours is limited to 250 hours in any given year.

7.(2)(f) LG&E Losses (GWH)

	1994	1995	1996	1997	1998
Annual Energy Loss	514	609	592	594	545

Note: Company use is included in the energy loss figures shown above.

7.(2)(g) Impact of Existing Demand Side Programs.

Impacts of the existing demand-side programs on energy and demand requirements are estimated in Table 8.(3)(e)(3).

7.(2)(h) Other Data Illustrating Historical Changes in Load and Load Characteristics.

A historical trend of average energy usage per customer by class is shown in Table 7.(2)(h)-1. In addition, historical class sales and per customer usage is broken down by end-use levels in Tables A5, A6, and A7 of Technical Appendix 1 in Volume II. Over the last ten years, the average usage of non-heating residential customers has been gradually increasing, while the per-customer usage of electric space-heating customers has been continuously declining with improved energy efficiency of electric space heaters. As combined, there has been an increasing trend for the residential per-customer usage. Average usage of the large commercial customers also shows an increasing trend, while the large power class has been experiencing a declining trend in its usage per customer. Per-customer usage of the general service and street lighting classes has been stable over the recent years.

A history of percentage share of class sales to total energy sales is presented in Table 7.(2)(h)-2. The ten-year history indicates that the relative shares of class sales have not changed significantly over the years. Although the overall residential class share of total energy sales has been stable, the same data also shows that the share of residential electric heating sales has been declining while the relative percentage of residential non-heating sales has been steadily growing.

Table 7.(2)(h)-1 LG&E Average Annual Usage per Customer by Class

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Residential Heating	19,011	18,016	19,008	17,872	19,030	18,995	18,722	19,461	18,112	17,263
Residential Non-Heating	8,814	8,935	9,964	8,732	9,672	9,474	9,946	9,759	9,473	10,456
Total Residential	10,182	10,167	11,203	9,975	10,937	10,750	11,106	11,032	10,598	11,334
General Service	33,902	34,095	35,572	33,512	34,446	34,834	35,341	35,074	33,477	34,749
Large Commercial	1,088,859	1,105,908	1,148,258	1,092,498	1,102,384	1,103,079	1,119,291	1,117,983	1,116,319	1,172,988
Large Power	8,194,526	7,985,473	7,671,008	7,303,265	7,046,502	7,088,456	7,074,280	7,039,249	6,805,989	6,922,419
Street Lighting	20,626	20,642	19,954	19,624	19,425	19,236	19,079	18,755	19,385	19,399
Total Customers	28,137	28,269	29,360	27,838	29,187	29,410	30,170	30,190	29,494	30,636

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Table 7.(2)(h)-2 LG&E Percentage of Class Sales to Total Energy Sales

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Residential Heating	8.0%	7.6%	7.8%	7.7%	7.8%	7.6%	7.2%	7.5%	7.0%	6.4%
Residential Non-Heating	24.0%	24.1%	25.9%	23.9%	25.3%	24.6%	25.3%	24.7%	24.6%	26.1%
Total Residential	32.0%	31.8%	33.7%	31.6%	33.0%	32.2%	32.5%	32.2%	31.6%	32.5%
General Service	12.0%	12.1%	12.2%	12.1%	11.9%	11.9%	11.6%	11.8%	11.7%	11.7%
Large Commercial	23.4%	23.5%	23.8%	24.2%	24.0%	23.9%	23.7%	24.0%	24.5%	24.6%
Large Power	32.0%	31.9%	29.7%	31.4%	30.4%	31.3%	31.5%	31.4%	31.6%	30.5%
Street Lighting	0.7%	0.7%	0.6%	0.7%	0.7%	0.7%	0.6%	0.6%	0.7%	0.6%
Total Customers	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

7.(3) Specification of Forecast Information Requirements.

The information regarding the energy sales and peak load forecasts in the following subsections conform to the specifications outlined in Section 7.(3) to the fullest extent possible.

7.(4)(a) LG&E Forecasted Sales by Class (GWH)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential	3,599	3,671	3,724	3,788	3,851	3,929	3,990	4,052	4,111	4,171	4,232	4,289	4,347	4,402	4,455
General Service	1,292	1,319	1,340	1,364	1,390	1,421	1,447	1,475	1,504	1,534	1,567	1,601	1,635	1,670	1,705
Large Commercial	2,743	2,867	3,120	3,238	3,295	3,353	3,418	3,486	3,556	3,628	3,708	3,787	3,869	3,950	4,030
Large Power	3,406	3,422	3,487	3,530	3,558	3,590	3,648	3,707	3,766	3,823	3,882	3,941	3,999	4,057	4,115
Street Lighting	70	71	72	73	74	75	76	77	77	78	79	80	81	82	83
	======	======	======	=====	=====	======	======	=====	======	=====	=====	=====	=====	=====	======
Total Sales	11,110	11,349	11,742	11,992	12,168	12,368	12,578	12,797	13,015	13,235	13,468	13,697	13,931	14,161	14,388
Generation	11,729	11,982	12,396	12,661	12,846	13,057	13,279	13,510	13,740	13,972	14,218	14,460	14,707	14,950	15,190

7.(4)(b) LG&E Summer and Winter Coincident Peak Demand (MW)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Summer	2,579	2,636	2,692	2,748	2,807	2,865	2,925	2,985	3,044	3,103	3,162	3,221	3,279	3,336	3,392
	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Winter	1,760	1,790	1,819	1,849	1,879	1,910	1,940	1,971	2,001	2,031	2,061	2,091	2,120	2,148	2,176

7.(4)(c) LG&E Monthly Energy Sales by Class (GWH), Generation (GWH) and Peak Demand (MW) Forecast

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	2000	301	261	244	221	275	378	467	442	311	237	242	293	3,671
	2001	305	255	248	225	281	385	476	449	318	242	245	296	3,724
General Service	2000	107	100	101	96	105	121	138	136	111	101	99	106	1,319
	2001	110	99	104	98	107	122	140	137	112	103	101	108	1,340
Large Commerci	2000	216	204	215	207	235	262	301	300	256	227	218	226	2,867
	2001	231	212	232	222	259	293	334	327	277	248	239	246	3,120
Large Power	2000	266	285	272	279	284	287	299	297	304	276	293	279	3,422
	2001	269	290	279	288	292	296	303	301	309	280	298	283	3,487
Street Lighting	2000	7	6	6	5	5	5	5	5	6	6	7	7	71
	2001	7	6	6	5	5	5	5	5	6	6	7	7	72
Total Sales	2000	896	855	839	808	903	1,053	1,210	1,181	989	847	859	910	11,349
	2001	922	862	868	838	943	1,100	1,258	1,220	1,022	880	890	940	11,742
Generation	2000	944	897	898	849	953	1,116	1,268	1,249	1,031	898	907	972	11,982
	2001	971	905	929	880	995	1,166	1,319	1,291	1,065	932	940	1,003	12,396
Peak Demand	2000	1,790	1,768	1,629	1,602	2,099	2,495	2,636	2,583	2,403	1,721	1,650	1,761	
	2001	1,819	1,797	1,656	1,627	2,143	2,548	2,692	2,637	2,453	1,757	1,677	1,790	

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7.(4)(d) Forecast Impact of Demand-Side Programs

The impacts of existing and future demand-side programs on both energy sales and peak demands are estimated in Table 8.(3)(e)(3). The energy sales and peak demand forecasts presented in the preceding sections do not include the impacts of those programs. The DSM-related adjustments to summer and winter peak demand and annual energy forecasts were made in Tables 8.(4)(a)-1, 8.(4)(a)-2 and 8.(4)(b) for both LG&E and KU combined.

7.(4)(e) Any Other Data to Illustrate Projected Changes in Load

None.

7.(5)(a) Historical Information for a Multistate Integrated Utility System.

This is not applicable to LG&E.

Historical Information for a Utility Purchasing More Than 50 Percent of Its Energy Needs.

This is not applicable to LG&E.

7.(5)(b) Forecast Information for a Multistate Integrated Utility System.

This is not applicable to LG&E.

Forecast Information for a Utility Purchasing More Than 50 Percent of Its Energy Needs.

This is not applicable to LG&E.

7.(6) Updates of Load Forecasts.

Updates will be filed when adopted by LG&E.

7.(7) Description and Discussion of Methods, Models, Data, Assumptions, and Judgements

7.(7) (a) Economic and Demographic Data

A first step in the forecast process, described in detail in Technical Appendix 1 of Volume II, involves the gathering of national, state, and service territory economic and demographic data that are used to specify models which describe the electric consuming characteristics of LG&E's customers.

LG&E utilizes the national economic forecast data from WEFA Group Inc., a well-respected and nationally recognized economic consulting firm used by many utilities. Growth prospects in the national economy are important to the projection of energy usage due to the close linkage between economic activity and the use of energy.

Sections A, B, C and D of Technical Appendix 1 present LG&E's regional economic, demographic and weather data and electric sales, peak demand, number of customers and end-use data sets which were used to develop the forecasting models and to produce the load forecasts.

The regional economic data and forecasts were provided by the University of Louisville (U of L) and the Regional Financial Associates, Inc. (RFA). The RFA's forecasts are focused on the Louisville Metropolitan area as a whole for 1999-2003. The U of L's forecasts cover each of the seven counties included in the Louisville Metropolitan Statistical Area (MSA) and the six Kentucky counties surrounding the Louisville MSA for 1999-2020. The customer projections were made on the basis of the regional demographic forecasts developed by the Center for Business and Economic Research at the University of Kentucky (CBER/UK) for the Kentucky Utilities Service Territory Econometric Model (KUSTEM) project. In both of the U of L's and UK's forecasting studies, WEFA Group's 20-year long-term forecasts released in the First Quarter of 1993 were utilized as inputs for national economic and demographic variables. Detailed reports on the U of L's and RFA's forecasts and their forecasting methodologies are provided in Technical Appendix 1 of Volume II. UK's KUSTEM forecast report is included as Subsection 1 of Technical Appendix 2, Volume II. Regional weather data were compiled from the National Oceanic and Atmospheric Administration (NOAA).

The time periods of the historical data used for estimating the forecasting models were 1994-1998 for the short-term energy sales model equations, 1981-1998 for the long-term energy sales equations, 1973-1998 for the peak demand model equations, and 1970-1998 for the number of customer projections. Pre-1981 data for energy sales modeling was not used in order to recognize the moratorium on natural gas service from 1971 through 1980 that distorted the normal relationship between electric energy consumption and socio-economic variables.

7.(7) (b) Key Assumptions and Judgements

Key assumptions and judgements used in producing LG&E's forecasts and determining the reasonableness thereof are provided in detail in Technical Appendix 1 of Volume II. The following key economic and demographic assumptions are the primary drivers of LG&E's Energy and Demand Forecast:

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- LG&E service area population will grow from 741,318 in 1999 to 797,321 in 2013, at an average annual growth rate of 0.5%.
- Number of persons per residential customer count will decrease from 2.32 persons in 1999 to 2.17 persons in 2013.
- Real per capita personal income in the Louisville MSA will increase from $24,212 in 1999 to $31,593 in 2013, at an average annual growth rate of 1.9%.
- Real price of electricity will become lower at an average annual rate of [redacted].
- Trade and service industry employment in the Louisville MSA will grow at an annual rate of 1.1%, while manufacturing employment will slightly decline for the next fifteen-year period.
- Future climate is reflected by the weather values averaged for the most recent twenty-year period.
- The saturation rate of residential air conditioners, combined for window units and central units, will increase from 94.9% in 1999 to 99.0% in 2013.

7.(7) (c) General Methodological Approach

Forecasting future energy and demand is important for the planning and control of the Company's operations. The forecast is a tool for decisions regarding construction of facilities, such as: power plants, transmission lines, and substations, all of which are necessary for providing reliable service.

The desired outcome of the forecasting process is a reasonable estimate so that the Company's strategies and goals of providing adequate and reliable electric service to its customers at the lowest reasonable cost can be attained. The sophisticated modeling techniques allow the energy and demand forecast to be tailored to address unique data characteristics and analysis needs. New forecasting approaches continue to be evaluated in order to improve all aspects of the load forecasting process.

This section documents the methodology employed for energy and demand forecasting for LG&E. Due to differences in the historical data series for LG&E and KU their recent merger, the energy and demand forecasting process for the 1999-2013 period has maintained existing forecast processes for each utility. For the combined system, the separately estimated demand forecasts are not considered to be strictly additive due to some slight non-coincidence in system peaks. Therefore, a final consolidation process for combined company system demand has been developed and will be discussed in this report.

The structure of LG&E's short-term and long-term energy sales models, number of customer model, and the peak demand model are explained in a summary form in Table 7.(7)(c).

Energy Sales Forecasting Models

Two types of econometric models were developed and complementarily used for energy sales forecasting: 1) a short-term forecasting model and 2) a long-term forecasting model. Both the short and long-term forecasting models were designed to produce energy sales forecasts by service class. Adopting the neoclassical economic theory of stock adjustment, the short-term (or short-run) model assumes a variable rate of utilization but a fixed stock of electric appliances, while the long-term (or long-run) model allows both a variable rate of utilization and a variable stock of electric appliances. Therefore, weather, price and other seasonal and economic variables which determine the utilization rate of appliance stock are considered to be appropriate variables to explain the short-run formation of electric energy consumption. On the other hand, the long-run model includes not only the variables considered in the short-run model but also levels of appliance stock and/or economic and demographic variables which affect levels of appliance stock and their utilization rates.

The short-term energy sales model equations were estimated on the basis of the monthly historical data for January 1994 - December 1998. The annual data for 1981-1998 were used to estimate the long-term energy sales model equations. The estimated model equations are presented in Tables E1 and E2 of Technical Appendix 1 in Volume II, with the results of the statistical tests performed on the equations. The final model specifications were chosen over many other alternative specifications whose estimated coefficients were in conflict with economic theories or were inferior in statistical fitness. An econometric PC software package called "EVIEWS" was utilized for estimating both the short-term and the long-term model coefficients and conducting statistical robustness tests.

The short-term energy sales model equations were used to produce monthly sales by class and generation requirement projections for 1999-2004. The long-term energy sales model equations were utilized to forecast annual sales by class and generation requirements for 1999-2013. The final projections of annual energy sales and generation requirements for 1999-2013 were determined by taking the short-term model forecasts for 1999-2004 and applying the future annual growth rates implied by the long-term model forecasts to the short-term model forecasts of energy sales and generation requirement in 2004. For each of the service classes, the long-term model forecasts of growth rates for 2005 and on were synchronized with the short-term model forecasts by using the ratio of long-term model growth rate to the short-term model growth rate in 2004.

Peak Demand Forecasting Model

The 1999 peak demand model has two equations; one for summer peak load and another for winter peak load. In both of the model equations, the number of residential customers was used to reflect the growth of the demographic base. The reason for using the number of residential customers to track the service area's population growth is that historical numbers of residential customers are directly observable and readily available, while annual population figures are estimates which are reported with a one or two year time lag in the census years. Temperature-Humidity Index averaged for the twenty-four hour period prior to the time of peak demand was included to accommodate the cumulative impact of weather on summer peak load. Heating degree hours at the time of peak demand was selected for the winter peak demand equation. The estimated model equations are presented in Table E2 of Technical Appendix 1.

Customer Forecasting Model

Both the short-term and long-term residential and small commercial (or general service) energy sales forecasts were produced by multiplying the per customer usage forecast from the energy sales model by the number of customers forecast from the customer forecasting model.

As explained in section 7.(7)(b), the annual total number of residential customers were forecasted based on the population projections provided by CEBR/UK and LG&E's projected number of persons per residential electric customer. LG&E's forecast of the number of persons per residential electric customer was produced by using the Gompertz-curve equation estimated in Table E2 of Technical Appendix 1.

As shown in Table A9 of Technical Appendix 1, the number of residential all-electric customers was fairly stable for the last several years. With the gas service moratorium lifted in August 1980, new residential customers and also existing all-electric customers were allowed to receive gas service. As heat pumps and electric resistance heaters installed during the moratorium period have reached the end of their service lives in recent years, the residential customers' conversion to gas service has become fairly active. The number of conversions in 1998 almost canceled out the number of new all-electric customer additions. The economic advantage of natural gas as a heating fuel source over electricity is quite obvious from the current level and foreseeable prospects of the gap between LG&E's gas and electricity prices. The main reason for new all-electric customers is their inaccessability to gas mains or the high cost of gaining access to gas mains. The number of residential all-electric customers is expected to grow from 40,723 in 1998 according to the annual growth rates estimated by prorating the annual growth rates projected for total residential customers with the average of 1997 and 1998 ratios of electric space-heating customer growth rate to the total residential customer growth rate.

The number of general service customers was forecasted as a function of growth in the population base and a long-term trend. The estimated model equation for general service customers is reported in Table E2 of Technical Appendix 1. As implied by a positive coefficient of the trend variable, per capita demand for retail trade, financial and other small commercial/industrial services would increase over time as the standard of living increases. Due to the same reasons cited for the case of all-electric residential customers, number of general service electric space-heating customers has been declining since 1991. The declining trend of those customers is reflected in Table A9 of Technical Appendix 1, along with the history of all-electric residential customers. The economic advantage of natural gas as a heating fuel source over electricity is assumed to continue during the forecast period. The number of general service electric space-heating customers was projected to decrease from 1,064 in 1998 at an annual rate of 1.42%. The annual rate of decrease was estimated from the average rate of decrease experienced in 1993-1998.

The short-term large commercial energy sales forecasting model is also a per customer usage model and requires customer projections to produce an energy sales forecast for the class. The annual growth rates projected for 1999-2004 were obtained by adjusting the average annual growth rate for 1993-1998 with RFA's short-term regional economic forecast.

Table 7.(7)(c) Structure of the 1999 Energy Sales, Peak Demand and Customer Forecasting Models

I. Short-Term Forecasting Model for Energy Sales by Class

1) Residential Energy Sales

a. Base (or non-weather-sensitive) usage per customer per day =
   f (trend).
b. Water heating and outdoor lighting sales by month =
   5-year annual compound growth rate applied to the previous year's sales.
c. Weather-sensitive usage per customer by month =
   f (HDD or CDD, trend, monthly variation factor for weather variable coefficients).

2) General Service (Small Commercial/Industrial) Energy Sales
(for both non-public-authority and public authority classes)

a. Base (or non-weather-sensitive) usage per customer per day =
   f (trend).

b. Water heating and outdoor lighting sales by month =
   5-year annual compound growth rate applied to the previous year's sales.

c. Weather-sensitive usage per customer by month =
   f (HDD or CDD, trend, monthly variation factor for weather variable coefficients).

3) Large Commercial Energy Sales
   (for both non-public-authority and public authority classes, and Fort Knox)

   a. Base (or non-weather-sensitive) usage per customer per day =
      f (trend).
   b. Weather-sensitive usage per customer by month =
      f (HDD or CDD, trend, monthly variation factor for weather variable coefficients).

4) Large Industrial (Power) Energy Sales

   a. Sales to twenty-five largest customers (75% of LP sales) =
      Individually forecasted with the future usage information gathered through the annual industrial customer survey and 5-year annual compound growth rate.
   b. Sales to other large power customers (25% of LP sales) =
      Collectively forecasted with 5-year annual compound growth rate adjusted for short-term regional economic forecast for 2000-2004.

5) Street Lighting Energy Sales

   Will increase at an annual rate of 1.28%, which is equal to the average annual growth rate for 1993-1998.

II. Long-Term Forecasting Model for Energy Sales by Class (Double Logarithmic Model)

1) Residential Sales

   a. Base (or non-weather-sensitive) usage per customer =
      f (average price per MWH and trend).
   b. Air-conditioning usage per customer =
      f (summer energy price per MWH, CDD, composite rate of air-conditioning saturation, per capita income and trend).
   c. Space-heating usage per electric space-heating customer =
      f (winter energy price per MWH, HDD, and trend).
   d. Space-heating usage per non-electric space-heating customer =
      f (winter energy price per MWH and HDD).

2) General Service (Small Commercial/Industrial) Energy Sales

a. Base (or non-weather-sensitive) usage per customer =
f (service industry employment per general service customer).
b. Air-conditioning usage per customer =
f (summer energy price per MWH, CDD, service industry employment per general service customer).
c. Space-heating usage per electric space-heating customer =
f (HDD and trend).
d. Space-heating usage per non-electric space-heating customer =
f (winter energy price per MWH and HDD).

3) Large Commercial Energy Sales =
f (average price per MWH, non-manufacturing employment, CDD, and trend).

4) Large Industrial (Power) Energy Sales =
f (industrial productivity index by SIC, electric energy intensity by industry, and trend).

5) Street Lighting Energy Sales =
f (number of street lights and energy efficiency trend reflected in the street lighting energy sales increase and residential customer growth for 1993-1998).

III. Peak Demand Model

1) Summer (or Annual) Peak Demand =
f (average THI for the 24-hour period prior to the time of peak demand and number of residential customers).

2) Winter Peak Demand =
f (HDH at the time of peak demand and number of residential customers).

IV. Customer Forecasting Model (Linear Model for Customers; Gompertz Curve for Size of Households)

1) Residential Customers =
f (service area population and average size of residential customer households).

2) General Service (Small Commercial) Customers =
f (service area population and trend).

3) Large Commercial Customers =
f (five-year average annual compound growth rate and regional economic forecast).

7. (7) (d) Treatment and Assessment of Forecast Uncertainty

The essence of the econometric modeling approach, such as the one utilized for producing the 1999 forecasts, is to quantify historical relationships which exist among the target variables to be forecasted and other variables which influence the behavior of the target variables. These quantified relationships are assumed to continue in the future and are used to develop a forecast. However, there are various possible sources of error or uncertainty inherent in this approach.

First, the relationships among the variables may be improperly quantified. A wide range of statistical tests and tracking measures were employed to minimize the possibility of improper quantification.

Second, the underlying structural relationships among the variables may change. If structural change occurs, neither econometric approaches nor other generally accepted forecasting methods would perform well. The best way to deal with this source of uncertainty is to regularly update the forecasting model. LG&E regularly updates its energy sales, peak demand and customer forecasts on an annual basis in an attempt to reduce this source of uncertainty and error.

A third source of error is that future values of the explanatory variables included in the forecasting models may vary from those used to generate the forecast. To address this uncertainty, the company develops optimistic and pessimistic scenarios to support sensitivity analysis of the various resource acquisition plans being studied. These scenarios are based on controlling future values of the most important variables to the forecast. For LG&E, the key uncertainty analysis variables are Population, Per Capita Personal Income, Employment by Industry, and Electricity price by class. The WEFA Group provided optimistic and pessimistic forecasts for national variables, which were processed down to the metro level for LG&E.

Quantitative assessment of the likelihood of the variables following their alternative paths depends on the individual vendors. WEFA states in its documentation that it believes there is a 70 percent probability that the economy will most closely resemble the trend, a 15 percent chance that is twill resemble the optimistic scenario, and a 15 percent chance that it will resemble the pessimistic case.

The following tables document the optimistic and pessimistic outlooks for LG&E:

Table 7.(7)(d)-1
LG&E Sales Baseline/Scenarios Comparison (GWH)

Year	Baseline Forecast	Optimistic Forecast	Pessimistic Forecast
1999	11,729	11,771	11,695
2000	11,982	12,077	11,916
2001	12,396	12,528	12,299
2002	12,661	12,828	12,531
2003	12,846	13,048	12,683
2004	13,057	13,295	12,862
2005	13,279	13,554	13,050
2006	13,510	13,821	13,249
2007	13,740	14,086	13,445
2008	13,972	14,356	13,642
2009	14,218	14,639	13,852
2010	14,460	14,919	14,057
2011	14,707	15,208	14,267
2012	14,950	15,492	14,474
2013	15,190	15,776	14,673

Table 7.(7)(d)-2
LG&E Base, Optimistic and Pessimistic Forecasts of Peak Demand (MW)

Year	Base Forecast	Optimistic Forecast	Pessimistic Forecast
1999	2,579	2,604	2,564
2000	2,636	2,682	2,607
2001	2,692	2,754	2,652
2002	2,748	2,828	2,699
2003	2,807	2,901	2,748
2004	2,865	2,975	2,798
2005	2,925	3,050	2,848
2006	2,985	3,124	2,901
2007	3,044	3,195	2,952
2008	3,103	3,267	3,004
2009	3,162	3,340	3,055
2010	3,221	3,412	3,107
2011	3,279	3,482	3,158
2012	3,336	3,551	3,208
2013	3,392	3,625	3,255

7.(7)(e) Sensitivity Analysis

The 1999 model forecast does not explicitly incorporate the development and potential market penetration of new appliances and other equipment and technologies that use electricity or competing fuels. No matter what type of modeling approach is adopted for the load forecasts, it would be pure speculation to separately predict the development and impact of new technologies. LG&E revises its load forecasts on an annual basis. Such frequent updating of the input assumptions and forecasts should gradually reflect the impact of new appliances and technologies as they emerge and penetrate into the energy market.

The impacts of existing and future demand-side programs on both energy sales and peak demands are shown in Tables 8.(3)(e)(3), 8.(4)(a)-1, 8.(4)(a)-2 and 8.(4)(b). Changes in demographic and economic conditions were analyzed by developing an optimistic and a pessimistic scenario of forecasts in addition to the base case. The economic and demographic variables controlled for alternative growth scenarios are the service area population, per capita personal income, electricity price by class, and Louisville MSA employment by industry. The optimistic and pessimistic forecasts of generation requirement for the system are presented in Table 7.(7)(d)-1. The optimistic and pessimistic views of annual peak load are shown in Table 7.(7)(d)-2. The values of economic and demographic variables used to produce the base, optimistic and pessimistic scenarios are provided in Tables B1, B2 and B3 of Technical Appendix 1 in Volume II.

7.(7)(f) Research and Development

Refer to Section 7.(7)(f) under the KU portion of Section 7.

7.(7)(g) Future Development of End-Use Load and Market Data

Refer to Section 7.(7)(g) under the KU portion of Section 7.

KENTUCKY UTILITIES

7.(1) Specification of Historical and Forecasted Information Requirements by Class

The data submissions in the following subsections were constructed to conform to the specifications provided in Sections 7.(1) to the fullest extent possible.

7.(2) Specification of Historical Information Requirements

The data submissions in the following subsections were constructed to conform to the specifications provided in Sections 7.(2) to the fullest extent possible.

7.(2) (a) KU Average Annual Historic Customers by Class

	1994	1995	1996	1997	1998
Residential Heating (FERS)	115,892	120,660	126,811	132,495	138,549
Residential Non-Heating (RS)	226,510	228,189	227,415	227,885	228,198
Total Residential	342,402	348,849	354,226	360,380	366,474
Commercial	64,897	66,594	67,636	69,459	71,310
Industrial	1,770	1,781	1,890	1,891	1,888
Utility Use & Other*	3,486	3,480	3,477	3,497	3,500
Virginia Retail	28,007	28,411	28,899	28,899	29,011
Sales for Resale	28	29	39	39	55
Total Customers	440,590	449,144	456,167	464,165	472,513

*Includes Lighting

7.(2) (b) KU Recorded and Weather-Normalized Annual Energy Sales & Generation and sales by class (GWH)

	1994	1995	1996	1997	1998
SYSTEM SALES (integrated) :					
Recorded	15,379	16,135	16,592	16,923	17,679
Weather Normalized	15,280	16,003	16,638	17,219	17,811
SYSTEM GENERATION (integrated):					
Recorded	16,381	17,191	17,599	17,863	18,727
Weather Normalized	16,282	17,059	17,645	18,159	18,859
SALES BY CLASS:					
Residential Heating (FERS)	2,087	2,212	2,386	2,343	2,348
Residential Non-Heating (RS)	2,244	2,415	2,351	2,323	2,517
TOTAL RESIDENTIAL	4,331	4,627	4,736	4,666	4,865
Commercial	3,921	4,073	4,126	4,128	4,387
Industrial	4,680	4,897	5,137	5,531	5,761
Utility Use & Other (equals Lighting)	80	82	83	86	83
Sales for Resale	1,563	1,642	1,684	1,695	1,780
TOTAL KU Kentucky Retail	14,574	15,321	15,766	16,107	16,876
VIRGINIA Retail	805	814	826	816	803
INTERNAL SALES	15,379	16,135	16,592	16,923	17,679

7.(2)(c) KU Recorded and Weather Normalized Coincident Peak Demands (MW)

	1994	1995	1996	1997	1998
SUMMER					
Integrated System Recorded	3,127	3,341	3,192	3,510	3,559
Integrated System Normalized	3,142	3,270	3,431	3,629	3,664
WINTER					
Integrated System Recorded	3,092	3,077	3,391	3,377	3,072
Integrated System Normalized	2,954	3,186	3,347	3,430	3,508

7.(2)(d) KU Energy Sales and Coincident Peak Demand for Firm, Contractual Committment Customers.

	1994	1995	1996	1997	1998
Energy Sales (GWH)	15,087	15,845	16,066	15,841	16,527
Coincident Peak Demand (MW)	2,942	3,164	3,014	3,565	3,290

7.(2)(e) KU Energy Sales and Coincident Peak Demand for Interuptible Customers

	1994	1995	1996	1997	1998
Energy Sales (GWH)	292.4	295.1	526	1082.1	1151.9
Coincident Peak Demand (MW)	47.2	42.7	127.7	198.2	129.3

7.(2)(f) KU Losses (GWH)

	1994	1995	1996	1997	1998
Energy (gWh)	1,002	1,056	1,007	940	1,048

7.(2)(g) Impact of Existing Demand Side Programs.

Impacts of the existing demand-side programs on energy and demand requirements are estimated in Table 8.(3)(e)(3).

7.(2)(h) Other Data Illustrating Historical Changes in Load and Load Characteristics

Historic actual sales and customer data as reported in tables 7.(2)(a-f) are calculated using the Company's Form 1 filings as the basis for class segmentation. KU's energy forecasting process is predicated primarily on rate code and SIC Code criteria, and is based on sales as billed rather than sales as used (before any unbilled adjustment) which creates an alternative perspective on growth. The historic data in this portion of the 1999 IRP for KU relies on the fifteen-year history of customers and energy sales as used for the energy forecasting models.

Total KU internal sales have grown at a compound average annual rate of 3.9 percent from 1983 to 1998. Figure 7.(2)(h) visualizes KU historic sales by class over the 1983–1998 period. Commercial and Industrial sales have shown the highest rates of growth over the fifteen-year historic period, averaging 5.0 percent on a combined basis. A shift in the allocation of reported sales in 1987 creates a distinct kink in the historic sales paths for Commercial and Industrial sales. Thus, these two sectors are combined in reporting historic growth rates. Full Electric Residential Service (FERS) sales at 4.1 percent have also grown faster than the company average of 3.9 percent. Table 7.(2)(h) presents historic growth rates by class of service from 1983 to 1998 and future growth rates as predicted by class in the 1993, 1996 and 1999 IRPs.

Figure 7.(2)(h)
KU Historic Billed Sales by Class

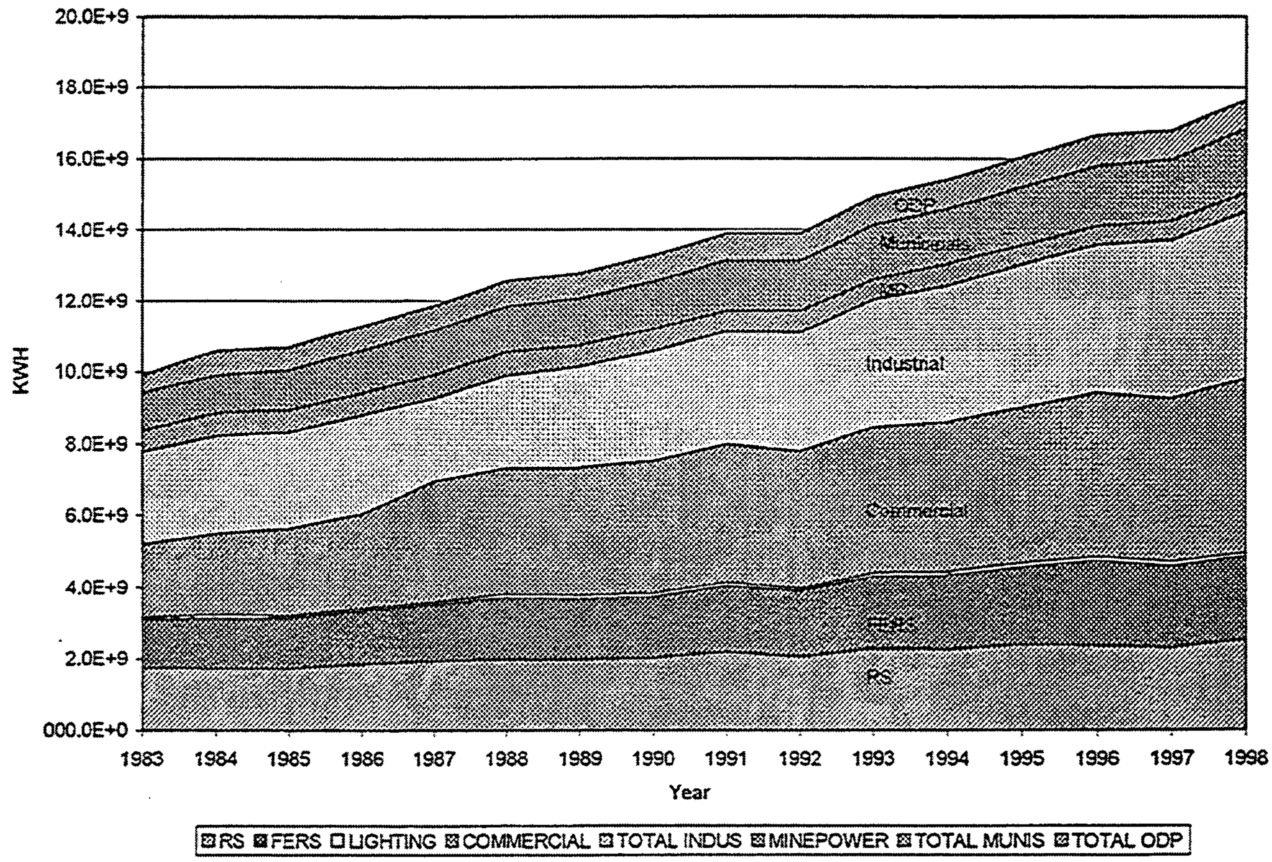

TABLE 7.(2)(h)
COMPARISON OF HISTORIC AND FORECASTED KU GROWTH RATES

Class	Historical Sales* (1983-1998)	1999 IRP (1999-2013)		1996 IRP (1996-2010)		1993 IRP (1994-2008)
		Company	Baseline	Company	Baseline	
Retail						
Kentucky	4.0	2.1	2.0	2.5	2.2	1.7
Residential	3.2	1.8	1.8	2.4	2.3	1.1
RS	2.4	.8	.8	1.3	1.2	0.1
FERS	4.1	2.7	2.7	3.3	3.3	2.1
Commercial/ Industrial	5.0**	2.45	2.37	2.6	2.1	2.1
Commercial		2.3	2.2	1.8	1.8	2.1
Industrial		2.6	2.4	3.1	2.5	2.1
Mine Power	-1.1	-2.1	-2.1	-0.2	-0.2	0.3
Lighting	1.1	.6	.6	2.7	1.7	1.7
Virginia	3.3	1.9	1.9			
Wholesale (Municipals)	3.6	2.1	2.1	3.4	2.4	2.3
Total Company	3.9	2.1	2.1	2.4	2.1	1.8

* Actual internal billed sales for the period 1993–1998

** The Commercial and Industrial growth rate is reported jointly for historic data due to a shift in allocation in internal databases in 1987. In the 1996 IRP, Mine Power was included in this joint reporting. For the 1999 IRP it is separated, and the reported joint growth rate for Commercial/Industrial for the 1996 IRP has been restated by removing Mine Power.

KU's Kentucky Retail Residential sales since 1983 have been driven by both increases in average usage per customer and incremental customer growth. Total residential customers have increased at an average annual rate of 1.5 percent, while average annual use per customer has risen from 10,301 kwh to 13,324, an average annual increase of 1.6 percent. Customer growth has been dominated by KU's FERS class, with 87 percent of net new customer growth coming as FERS customers (65,013 FERS vs 10,122 RS). Growth in usage per customer is attributable solely to the RS class, which has increased average usage from 8,107 KWH in 1983 to 11,083 KWH in 1998 (average annual growth rate of 2.1 percent). FERS usage per customer has been essentially flat, with a slight decline from 17,595 KWH in 1983 to 17,014 KWH in 1998 (average annual growth rate of -.2 percent). In general, it appears that the increased efficiency of electric space heating and equipment, particularly heat pumps, has had a mitigating effect on overall FERS load growth.

Table 7.(2)(h)-2 shows estimates of KU's historical appliance saturation trends. Increases in RS usage per customer are likely due to increases in the saturation of air conditioning and for many appliances in combination with increased average housing size. The saturation of FERS air conditioning and for several appliances has also increased while heat pumps have become increasingly prevalent, stabilizing the rate of change in average usage per customer.

KU's Kentucky Retail Commercial class has also experienced growth in both its customer base and average annual usage per customer. Using 1987 data as a starting point, customers have increased from 56,253 to 70,073 in 1998, for an average annual

Table 7.(2)(h)-2
Electric Appliance Saturations

APPLIANCE	RS RATE (%)							
	1970	1983	1985	1987	1989	1991	1993	1997
Refrigerator	97	100	100	100	100	99	100	100
Freezer	34	59	40	50	56	49	50	44
Color TV	-	87	88	93	95	96	-	-
Black & White TV	-	45	37	31	32	21	-	-
Video Recorder	-	-	15	35	50	59	-	70
Home Computer	-	-	9	11	11	12	15	33
Range	55	64	67	66	69	63	66	72
Microwave Oven	-	27	38	58	72	83	83	91
Dishwasher	17	39	37	39	43	36	40	59
Clothes Washer	79	84	83	87	86	82	85	88
Clothes Dryer	36	64	67	71	70	70	71	78
Water Heater	31	38	39	32	30	35	37	36
Dehumidifier	-	-	14	16	17	16	10	12
Air Conditioning								
Total	49	73	69	84	84	84	79	84
Central A/C	12	34	32	43	47	49	49	66
Room A/C	37	39	37	41	37	35	50	18
Primary Home Heating	5	7	5	9	7	8	6	6

APPLIANCE	FERS RATE (%)							
	1970	1983	1985	1987	1989	1991	1993	1997
Refrigerator	-	100	99	100	100	100	100	100
Freezer	-	50	37	40	40	47	44	45
Color TV	-	91	91	94	96	98	-	-
Black & White TV	-	48	41	31	30	21	-	-
Video Recorder	-	-	20	50	61	69	-	73
Home Computer	-	-	13	17	17	15	16	32
Range	-	96	99	99	97	94	92	93
Microwave Oven	-	36	47	67	75	88	88	91
Dishwasher	-	51	51	58	56	51	50	59
Clothes Washer	-	87	83	84	82	77	78	83
Clothes Dryer	-	83	79	79	78	76	76	83
Water Heater	-	95	96	96	97	98	98	98
Dehumidifier	-	-	14	15	13	13	9	14
Air Conditioning								
Total	-	84	83	93	88	94	93	97
Central A/C	-	47	54	68	66	68	69	83
Room A/C	-	37	29	25	22	26	24	14
Primary Home Heating	-	93	92	93	94	94	93	94

growth rate of 2.0 percent. Usage per customer over the same time period has grown from 59,636 KWH to 68,970 KWH, an average annual growth rate of 1.3 percent.

Growth in KU's Kentucky Retail Industrial class has come predominantly from growth in average usage per customer. Again using 1987 as a starting point, customers have increased from 3,441 to 3,595, for an average annual growth rate of only .4 percent. However, average annual usage per customer has grown from 673,878 KWH in 1987 to 1,318,069 KWH in 1998, averaging a very high 6.3 percent rate of growth. About two-thirds of this growth has come from general industrial usage and one-third from growth in the usage level of KU's individually forecasted large industrial customers (average annual general industrial usage was 987,534 KWH in 1998).

Mine Power sales have been in general decline over the fifteen-year historic period. In 1983, Mine Power sales were 604 GWH, while in 1998 they were only 515 GWH. The loss of sales is almost solely attributable to a reduced number of customers on the Mine Power rate, with customers falling from 62 in 1983 to 53 in 1998.

Lighting sales are a small component of overall historic energy sales, growing from 87 GWH in 1983 to 102 GWH in 1998. All growth has come in the area of outdoor lighting, which has increased from 33 GWH to 58 GWH over the historic period. Street Lighting sales have fallen from 53 GWH to 44 GWH over the period due to increasing efficiency of fixtures.

Virginia sales growth has been driven by both increases in customers and in usage per customer. Customers have grown at a relatively slow rate of .9 percent per year over the fifteen-year historic period, while usage per customer has grown at an average annual rate of 2.4 percent. Most of the growth in Virginia sales have come from its Commercial and Industrial sectors.

Wholesale (Municipal) sales grew at a 3.6 percent annual rate over the last fifteen years. Sales to the Wholesale sector are segmented for system-level demand into four segments, Primary Voltage, Transmission Voltage, City of Paris and City of Pitcairn, Pennsylvania. Most Wholesale growth has occurred in Primary Voltage sales at 3.8 percent over the last fifteen years, with Transmission Voltage sales close behind at 3.5 percent.

7.(3) Specification of Forecast Information Requirements.

The information regarding the energy sales and peak load forecasts in the following subsections conform to the specifications outlined in Section 7.(3) to the fullest extent possible.

7.(4)(a) KU Forecasted Sales by Class and Total Generation (GWH)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential RS	2,472	2,484	2,509	2,543	2,563	2,587	2,594	2,612	2,632	2,649	2,669	2,691	2,713	2,736	2,760
Residential FERS	2,606	2,707	2,796	2,877	2,974	3,079	3,140	3,222	3,305	3,383	3,465	3,546	3,625	3,705	3,785
Total Residential	5,078	5,191	5,305	5,420	5,538	5,665	5,734	5,833	5,937	6,032	6,134	6,237	6,337	6,440	6,545
Commercial	4,925	5,119	5,244	5,403	5,543	5,679	5,775	5,901	6,026	6,151	6,278	6,407	6,535	6,663	6,793
Industrial	4,923	5,152	5,288	5,420	5,560	5,699	5,830	5,943	6,083	6,226	6,370	6,515	6,659	6,803	6,949
Mine Power	502	475	476	466	459	479	493	480	466	460	450	449	407	389	374
Lighting	101	102	102	102	104	106	106	107	108	109	109	110	110	110	110
Municipals	1,836	1,888	1,942	1,998	2,056	2,114	2,158	2,214	2,269	2,325	2,381	2,436	2,491	2,546	2,602
	======	======	=====	======	=====	======	=====	======	=====	=====	======	======	=====	=====	======
Sales w/o Va	17,365	17,927	18,357	18,809	19,260	19,742	20,096	20,478	20,889	21,303	21,722	22,154	22,539	22,951	23,373
Virginia	879	898	916	935	954	974	996	1,018	1,041	1,064	1,082	1,105	1,122	1,133	1,146
Total Sales	18,244	18,825	19,273	19,744	20,214	20,716	21,092	21,496	21,930	22,367	22,804	23,259	23,661	24,084	24,519
Generation	19,324	19,994	20,413	20,913	21,409	22,003	22,341	22,769	23,231	23,760	24,154	24,636	25,064	25,583	25,872

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7.(4)(b) KU Summer and Winter Coincident Peak Demand (MW)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Summer	3,804	3,930	4,009	4,092	4,180	4,300	4,384	4,471	4,543	4,609	4,698	4,807	4,903	4,983	5,048
	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Winter	3,586	3,690	3,771	3,868	3,967	4,091	4,160	4,234	4,324	4,417	4,521	4,628	4,692	4,789	4,856

*Before adjustment for Curtailable Service Rider load of 28 MW in the summer and winter seasons

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7.(4)(c) KU Monthly Energy Forecast (GWH)

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential Heating(FERS)	1999	208	198	175	167	158	205	270	301	258	180	162	190	2,472
	2000	212	198	176	167	159	205	271	302	259	180	163	191	2,483
Residential Heating(RS)	1999	345	335	263	210	146	151	189	189	178	141	184	275	2,606
	2000	360	341	281	216	152	158	198	197	186	144	191	284	2,708
Total Residenti	1999	553	533	438	377	304	356	459	490	436	321	346	465	5,078
	2000	572	539	457	383	311	363	469	499	445	324	354	475	5,191
Commercial	1999	419	399	383	373	363	417	470	466	480	383	367	405	4,925
	2000	436	415	399	389	377	433	488	483	497	398	382	422	5,119
Industrial	1999	427	443	438	444	439	465	454	471	487	447	454	456	5,425
	2000	446	466	456	460	455	481	471	487	503	463	469	471	5,628
Total C/I	1999	846	842	821	817	802	882	924	937	967	830	821	861	10,350
	2000	882	881	855	849	832	914	959	970	1,000	861	851	893	10,747
Lighting	1999	10	9	9	8	7	7	7	8	8	9	10	11	103
	2000	10	9	9	8	7	7	7	8	8	9	10	11	103
Sales for Resal	1999	157	139	142	131	140	166	190	184	155	140	137	155	1,836
	2000	160	142	145	134	144	169	194	188	158	142	140	159	1,875
Total Sales w/o Virginia	1999	1,566	1,523	1,410	1,333	1,253	1,411	1,580	1,619	1,566	1,300	1,314	1,492	17,367
	2000	1,624	1,571	1,466	1,374	1,294	1,453	1,629	1,665	1,611	1,336	1,355	1,538	17,916
Virginia	1999	98	93	86	76	63	60	60	62	62	60	70	88	879
	2000	100	95	87	78	64	61	62	64	64	61	72	89	898
Total Sales	1999	1,664	1,616	1,496	1,409	1,316	1,471	1,640	1,681	1,628	1,360	1,384	1,580	18,246
	2000	1,724	1,666	1,553	1,452	1,358	1,514	1,691	1,729	1,675	1,397	1,427	1,627	18,814
Generation	1999	1,670	1,402	1,511	1,370	1,436	1,603	1,841	1,681	1,489	1,352	1,427	1,612	18,394
	2000	1,777	1,477	1,587	1,409	1,484	1,680	1,877	1,746	1,512	1,401	1,495	1,646	19,091

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7.(4)(d) Forecast Impact of Demand-Side Programs

The impacts of existing and future demand-side programs on both energy sales and peak demands are estimated in Table 8.(3)(e)(3). The energy sales and peak demand forecasts presented in the preceding sections do not include the impacts of those programs. The DSM-related adjustments to summer and winter peak demand and annual energy forecasts were made in Tables 8.(4)(a)-1, 8.(4)(a)-2 and 8.(4)(b) for both LG&E and KU combined.

7.(4)(e) Any Other Data to Illustrate Projected Changes in Load

None.

7.(5)(a) Historical Information for a Multistate Integrated Utility System.

Virginia energy sales data for KU constitute only about 5 percent of total sales. Energy sales for Virginia have been shown as a separate line item in table 7.(2)(b), while demand is treated as part of KU's overall system demand.

Historical Information for a Utility Purchasing More Than 50 Percent of Its Energy Needs.

This is not applicable to KU.

7.(5)(b)-1 Forecasted Annual Energy Sales and Generation (KU/LG&E Integrated System) (MW)*

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Sales	29,358	30,173	31,014	31,734	32,379	33,083	33,669	34,292	34,947	35,600	36,271	36,955	37,591	38,245	38,906
	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Generation	31,057	31,979	32,812	33,577	34,258	35,063	35,623	36,282	36,974	37,735	38,375	39,099	39,774	40,536	41,065

* Prior to consideration of KU curtailable rider related sales reductions of approx. 4 GWH per year.

7.(5)(b)-2 Forecasted Summer and Winter (KU/LG&E Integrated System) (MW)*

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Summer	6,351	6,531	6,665	6,806	6,952	7,128	7,271	7,417	7,547	7,673	7,819	7,987	8,138	8,276	8,398
	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Winter	5,282	5,415	5,527	5,654	5,783	5,935	6,033	6,158	6,260	6,382	6,514	6,650	6,744	6,871	6,966

*Native load before adjustment for KU curtailable and LG&E interruptible load

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7.(6) Updates of Load Forecasts.

Updates will be filed when adopted by KU.

7.(7) Description and Discussion of Methods, Models, Data, Assumptions, and Judgements

7.(7) (a) Economic and Demographic Data

A first step in the forecast process, described in detail in Technical Apendices 1 and 2 of Volume II, involves the gathering of national, state, and service territory economic and demographic data that are used to specify models which describe the electric consuming characteristics of LG&E's and KU's customers.

To insure consistency within the planning function, LG&E and KU both utilize the national economic forecast data from WEFA Group Inc., a well-respected and nationally recognized economic consulting firm used by many utilities. Growth prospects in the national economy are important to the projection of energy usage due to the close linkage between the national and regional economic activities and the use of energy.

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For KU, WEFA generated national forecast data is fed to the University of Kentucky Center for Business and Economic Research's (UK/CBER) State Econometric Model. The UK State Econometric Model produces value-added output forecasts for over 30 industries and employment forecasts for nearly 70 sectors. Income is forecast for 7 sources of income and population for 36 age and gender cohorts. The model has been operated by the Center for Economic Research since 1995. A UK/CBER report on the economic and demographic forecast for KU is attached as Subsection 1 of Technical

Appendix 2, Volume II, and a detailed description of the model's methodology is attached as Subsection 2 of Technical Appendix 2, Volume II.

State forecasted data from the State Econometric Model for value-added output, employment, and income as well as national forecasts for total employment and selected industrial production indices are fed to the Kentucky Utilities Service Territory Economic Model (KUSTEM), which is also a product of UK/CBER. KUSTEM is an employment-driven model in which forecasts of sector level value-added output, employment, income, population and households are generated for five KU regions and then summed to create system-level class forecast drivers.

Demographic trends are an important part of the forecasting process. Population and number of persons per household forecasts work together in the KUSTEM model to create a household forecast, which is a key driver in the development of a total Kentucky Retail residential customer forecast. Kentucky Retail residential customers are in turn used to explain growth in commercial customers. Virginia residential customers are forecast using a population forecast developed by the Virginia Employment Commission.

KU's forecast of long term residential sales is a function of customers by class and sales per customer by class. Total residential customers are split between Full-Electric Residential Service (FERS) customers and Residential Service (RS) customers using the REEPS end-use model. Assumptions regarding electricity and competing fuel price are an important component to the forecast of customers by class. KU develops an internal forecast of electricity price and obtains a forecast of regional gas and oil prices from the WEFA Group.

Personal income from the KUSTEM model is used as an explanatory variable in KU's long term forecast of residential electricity sales per customer for both FERS and RS customers. The KUSTEM model forecasts income as the sum of five components; earnings by place of residence, dividends, interest and rent (DIR) income, transfer income, farm earnings and military earnings.

KU service territory manufacturing value-added output, referred to as Real Gross State Product (RGSP), is a key explanatory variable for industrial sales. The manufacturing sector is assumed to reflect SIC codes 20–39 and the mining category of SIC codes 10–14. The RGSP forecast used in forecasting industrial sales is the sum of the output estimates for each of these SIC codes.

The forecast of commercial sales requires both a forecast of commercial customers and a forecast of sales per customer. The commercial customer forecast is driven by the forecast of residential customers, while the sales per customer forecast is primarily a function of service territory commercial employment. The Commercial sector is assumed to reflect SIC codes 7-9, 15-19 and 40-89. The commercial employment forecast used in forecasting commercial sales is the sum of the employment estimates for each of these SIC codes.

Mine Power sales are forecast using a coal production forecast for East and West Kentucky obtained from Resource Data International (RDI). The forecast is disaggregated by producing mine, allowing the forecast to reflect at the mine level the assumed impacts of Phase I of the Clean Air Act Amendment of 1990 and Phase II, which goes into effect in 2000. Assumptions are made regarding the market share of this tonnage which will be served by KU and the average KWH usage per ton extracted in order to generate the sales forecast.

Several of the energy forecast class models contain electric price as an explanatory variable. The Forecasting and Budgeting Department of LG&E/KU developed an internal price forecast based on the merger sur-credit, fuel expense, environmental cost recovery associated with NOx, and a Commission-ordered refund. No general rate increase is assumed.

Weather data is a very important aspect of electricity sales forecasting. KU receives its weather data from the National Climatic Data Center (NCDC), a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. A twenty-year average or "normal" weather estimate is used for both cooling and heating degree days. Lexington Kentucky, Bristol Virginia, and Evansville Indiana weather station data are used depending on the area being modeled. Degree-days have varying bases in order to best capture weather effects by sector and by month.

KU also relies on company-collected report and survey data as inputs to the forecasting process. Such data enables KU to estimate the percentage of new residential customers choosing the Full Electric Residential Service (FERS) rate by type of housing, the availability of gas at new hookups, the mix of residential housing types on the KU system, the approximate saturation level of various appliances, and the sales history by key Standard Industrial Classification (SIC) codes.

7.(7) (b) Key Assumptions and Judgements

Key assumptions and judgements used in producing LG&E/KU's forecasts and determining the reasonableness thereof are discussed in detail in Technical Appendices 1 and 2 of Volume II. The following key economic and demographic assumptions are the primary drivers of KU's Energy and Demand Forecast:

- Annual U.S. Real Gross Domestic Product growth will average 2.0 percent over the next five years and 1.9 percent over the next fifteen years.
- Households in KU-served counties are predicted to increase at a 1.8 percent annual average rate over the next five years, and 1.3 percent over the next fifteen years.
- Future climate is reflected by the weather values averaged for the most recent twenty-year period.
- Over the next five years, it is predicted that approximately 45 percent of all new households in KU-served counties will locate on KU territory. From 2000 to 2010, the percentage slips to approximately 42 percent.
- Residential customers are predicted to increase at a 1.7 percent annual rate for the next five years, and at a 1.1 percent annual rate over the next fifteen years.
- The nominal retail price of electricity is predicted to rise at an average annual rate of [redacted] percent over the next fifteen years due to increases in generation fuel costs. Discounted for the general rate of expected future inflation, real price is expected to decrease.
- The nominal residential price of gas is predicted to rise at an average annual rate of [redacted] percent over the next five years and [redacted] percent over the next fifteen years.
- KU service territory industrial output is predicted to increase at 3.7 percent annual rate for both the next five years and 3.5 percent for the next fifteen years.
- KU service territory commercial employment is predicted to increase at an average annual rate of 1.6 percent for the next five years and 1.9 percent over fifteen years.

- East Kentucky coal production is predicted to rise at a 0.6 percent average annual rate for both the next five years and fifteen year periods. West Kentucky coal production is predicted to decline at an average annual rate of 0.1 percent for the next five years and increase at an average annual rate of 0.7 percent for the next fifteen years.
- Appliance efficiency standards as set by the National Energy Policy Act of 1992 are reflected in the forecast.

7.(7) (c) General Methodological Approach

Forecasting future energy and demand is important for the planning and control of the Company's operations. The forecast is a tool for decisions regarding construction of facilities, such as: power plants, transmission lines, and substations, all of which are necessary for providing reliable service.

The desired outcome of the forecasting process is a reasonable estimate so that the Company's strategies and goals of providing adequate and reliable electric service to its customers at the lowest reasonable cost can be attained. The sophisticated modeling techniques allow the energy and demand forecast to be tailored to address unique data characteristics and analysis needs. New forecasting approaches continue to be evaluated in order to improve all aspects of the load forecasting process.

This sub-section documents the methodology employed for energy and demand forecasting for Kentucky Utilities (KU). Due to differences in the historical data series for the two companies and their recent merger, the energy and demand forecasting process for the 1999-2013 period has maintained existing forecast processes for each utility. For the combined system, the separately estimated demand forecasts are not considered to be strictly additive due to some slight non-coincidence in system peaks.

Therefore, a final consolidation process for combined company system demand has been developed and will be discussed in this report.

The KU Energy Forecast addresses three basic jurisdictional groups: Kentucky-Retail, Virginia-Retail, and Wholesale sales to eleven municipally-owned utilities in Kentucky, Berea College (a privately owned utility serving the city of Berea), and Pitcairn, Pennsylvania. The distribution of predicted sales by jurisdiction for 1999 is 85.1% Kentucky-Retail, 4.8% Virginia-Retail, and 10.1% Wholesale.

The KU Energy forecast as generated within each group is disaggregated by classes in order to address the unique characteristics identifiable within each class. Typical classes include Residential, Commercial, and Industrial sales. The number of customers as well as Gigawatt-Hours (GWH) are forecasted, with some models based on a Kilowatt-Hours (KWH) per customer forecast. Econometric and end-use modeling techniques were used with minimal use of trending.

The use of econometric forecasting by KU is consistent with the rationale stated above for LG&E. It provides a theoretically sound basis for testing the relevance of various economic and demographic factors for significance as explanatory variables of electricity sales, and provides the framework to utilize forecasts of significant factors to generate forecasts of electricity sales.

The residential sales forecasting process embodies a combination of short-term econometric and end-use modeling methodologies. Each model is designed to contribute to a specific need of the forecasting process.

The following discussion provides an overview of the methodologies employed for developing the KU energy and demand forecast. Please refer to Appendix 2 of Volume II for a complete description of each sector's modeling process.

KU's forecasting process for Kentucky Retail Residential sales embodies a combination of short-term econometric and end-use modeling methodologies. Each model is designed to contribute to a specific need of the forecasting process.

The residential sales forecast is developed in three parts: (1) a projection of customers by rate class (2) a projection of short-term (three years) monthly energy sales by class and (3) a projection of long-term annual energy sales by class.

The forecast of total residential customers begins with a county-level population forecast that is generated by the KUSTEM (Kentucky Utilities Service Territory Economic Model) model developed by the University of Kentucky Center for Business and Economic Research (CBER). The KUSTEM model utilizes birth and mortality rate data from the Center for Urban and Economic Studies (CUER) at the University of Louisville. However, the KUSTEM model generates forecasts of migration based on the model's forecast of employment growth in Kentucky counties rather than past migration trends, as is the case for CUER population forecasting models. The KUSTEM model utilizes forecasts of population growth to forecast household growth. The primary driver of the KU customer forecast is the county level household forecast.

KU's customer model relates increases in the number of customers to growth in the number of households for the Company's service territory. A customer growth forecast for each individual county is generated by a selection process between regressions of historical customers to households or trending of KU's market share in a county (customers/households). Acceptable statistical results were obtained for 91 percent of the customer base using the customer to household regression method, while another 4 percent of the customer base was estimated using trended county market shares. A very small number of customers were in four counties that have exhibited no growth and are fixed at their current levels. This ability to restrict household growth enables the Company to account for service territory growth constraints. To date, no such constraints have been imposed on the forecast.

These projected customers are apportioned between the all-electric (FERS) and non all-electric rate classes (RS) through the use of a Customer Allocation Model. The discrete choice logic embedded in EPRI's Residential End-Use Energy Planning System (REEPS) model has been used to forecast FERS customers. This discrete choice methodolgoy specifically enables the Company to account for multiple factors such as:

- Influence of space cooling preferences on heat equipment choice
- Impact of capital and operating costs on HVAC system choice
- Impact of changing efficiency standards
- Influence of developers on HVAC system choice
- Influence of non-economic factors (i.e. customer perceptions and attitudes)

The results are then calibrated to the actual net annual change in FERS customers. The net annual change in RS customers is calculated by subtracting the FERS customer forecast from the total residential customer forecast.

Two econometric models, one for the FERS class and one for the RS class, are developed as a means of modeling short-term monthly kWh per customer for each residential class. The primary advantage of this model is its ability to capture recent cycles or trends in energy consumption and incorporate them into its projection of future energy consumption. An annual model can only capture trends over longer periods of time. Consequently, the short-term model should be a better predictor of a one to five year time horizon.

In the short-run econometric models monthly consumption is related to lagged consumption, weather, price and seasonal binary variables. The projections from the short-term models are merged with long-term outlooks in a manner that creates continuity between the outlooks.

For the residential sector long-term forecast, the REEPS model is utilized. REEPS generates an annual sales forecast based on the discrete choice-modeling framework. The model utilizes choice equations to construct a "multinominal" share system for all defined end-uses. Each equation relates the market share of an end-use to its economic attractiveness relative to the economic attractiveness of alternate technologies. This results in a market share forecast. These appliance shares are multiplied times the customer forecast and then a kWh per appliance forecast to derive an energy forecast by rate class. Both appliance shares and kWh per appliance are derived within the model. Customers are derived external to the model, as explained above. Separate REEPS databases are constructed for the FERS and RS classes. This gives KU the flexibility to develop models that reflect the unique demographic and energy usage characteristics of each customer class.

The KU Kentucky Retail Commercial sector sales forecasting process is a combination of short-tem and long-term econometric and end-use modeling methodologies. Short-term and long-term sales are forecast as the product of customer and KWH per customer forecasts. Commercial customers are forecast as a function of residential customers and a binary term starting in 1987 to capture the effect of a shift in historic data due to the use of SIC codes to segment commercial and industrial customers. The short-term model uses monthly KWH per customer as the dependent variable. Monthly KWH per customer is forecast using KWH per customer lagged one period, commercial service territory employment, and monthly weather terms.

The long-term forecast is based on cooling and heating seasonal kWh per customer models. For the cooling season model, the explanatory variables are service territory commercial employment, cooling degree days, the real average commercial price of electricity, a binary variable designed to capture the effect of SIC code based segmentation beginning in 1987, and an interaction term between commercial employment and the binary variable. For the heating season model, the explanatory variables are service territory employment, heating degree days, the real average commercial price of electricity, a binary variable designed to capture the effect of SIC code based segmentation beginning in 1987, and an interaction term between commercial employment and the binary variable.

KU utilizes the COMMEND (Commercial end-use model) of EPRI in its system-level forecasting to make an adjustment to the econometric generated forecast for the effects of appliance efficiency standards from the National Energy Policy Act of 1992 and the National Appliance Energy Conservation Act of 1987 (although the 1987 Act effects may already be largely incorporated in the historic data). The model is similar to REEPS in that it uses an integrated end-use econometric modeling framework which combines engineering concepts with economic relationships at the individual appliance level.

COMMEND provides a default database for all parameters that has been derived from national surveys and examinations of utility data. These databases have been modified to reflect available KU-specific data obtained from the 1992 KU Commercial Survey. This survey was designed as a means of populating key data inputs to the COMMEND model. The estimated effects of appliance efficiency are captured by running the COMMEND model with and without its standards module activated. These results are allocated to the cooling and heating seasons and deducted from the annual forecasts generated by the econometric model.

The forecast for sales to the KU Kentucky Retail Industrial sector has been produced using a monthly econometric model and annual econometric model, along with a small number of individual customer forecasts. The results from the monthly model and the annual model are weighted so as to phase in a long-term forecast.

The monthly model used monthly kWh as the dependent variable. The explanatory variables are service territory output, a seasonal binary for January, June cooling degree-days, July cooling degree-days, August cooling degree-days, and September cooling degree-days.

Annual kWh consumption is the dependent variable in the annual model. The explanatory variables are real service territory manufacturing output, the real average industrial price of electricity, cooling degree-days using a 70-degree base, and an annual dummy variable beginning in 1985.

Four large industrial KU customers are individually forecasted. The forecast for these customers are developed based on recent history in sales and demand and on communications with each customer regarding its outlook for growth and expansion.

To forecast KU Kentucky Retail Mine Power sales, KU incorporates intensity of use and market share analyses. Utilizing billing data, the RDI coal production history, Company field office knowledge, an average kWh/ton extracted on KU territory and KU's approximate share of coal production for 1997 were calculated for the Eastern and Western Kentucky regions. The analysis was based on data associated with 90 percent of total Mine Power sales. These values were then applied to KU's forecast of coal production in each region to estimate future sales for 1999 and beyond.

KU-Retail lighting sales are forecasted in two groups, outdoor area lighting and street lighting. The outdoor area group is projected utilizing two regression models, one for the number of fixtures and one for the average KW rating per fixture. The fixture count times the consumption rate times hours of use determines the energy forecast. Fixtures are regressed against service territory households and a binary variable that accounts for a revision of the fixture accounting procedure in 1987. As fixtures are a physical unit, the projected fixture values are adjusted so that the last year of known values equal the predicted values. Average KW rating per light for outdoor area lighting is regressed against time and a binary variable that accounts for the impact of the fixture count revision in 1987 on average KW rating per light.

The Company provides incandescent, mercury vapor and high pressure sodium (HPS) street lighting service. Incandescent lights are not available for new installations and the price differential between mercury vapor and HPS lights effectively eliminate requests for new mercury vapor systems. The forecast assumes that all new street lights will be HPS. The street lighting group uses the same methodology as the area lighting group for the fixture forecast. Fixtures are regressed against time and the binary variable for the 1987 revision.

The Old Dominion Power Company (ODP) operating unit of Kentucky Utilities serves five counties in southwestern Virginia. As these sales occur in the Virginia jurisdiction, they are modeled separately from other retail sales. ODP sales are disaggregated to a rate class basis. In the determination of KU system output, a two-step process of accounting for losses is employed for ODP that first brings sales up to the state line and then adjusts for the Kentucky system monthly loss factor.

Old Dominion Power Company (ODP) has one residential rate class for both all-electric and non all-electric customers. The forecast for this class is develop in two parts: (1) a projection of customers and (2) a projection of long term energy sales. The cooling season is June through September and the heating season is October through May. Degree-day data are based on 65 degrees and derived from data from the Bristol, Tennessee weather station.

The customer forecast is initiated using a population forecast developed by the Virginia Employment Commission. A ratio of customers to population is computed by county and trended over the forecast period. Future customers are then estimated by multiply the trended ratio of customer to population period. Future customers are then estimated by multiplying the trended ratio of customer to population by the population forecast.

For the residential sector, the Residential End-Use Planning System (REEPS) model is utilized. Since Virginia has only one class of residential service, only one REEPS database has been constructed utilizing internal data on customer usage and survey based saturation data. Weather data for the model is based on the Bristol weather station.

Commercial and Industrial sales have been forecast separately to determine the customer outlook and jointly to forecast gWh sales. The customer forecasts are a function of time since 1970 for the LP class and since 1980 for the GS class. The joint approach to forecasting GWH sales utilizes a SIC code based methodology.

The GWH model disaggregates the two rate classes into three portions; Westmoreland Coal, all other SIC Code 12 (Mining) and Commercial/Industrial. For the Westmoreland Coal portion, sales were set to Zero for the forecast period to reflect the closing of their operations. 27 GWH was added to reflect the new Wallings Ridge State Prison becoming fully operational. All other SIC code 12 sales were trended from 1979-1998 to best reflect recent history. The other commercial/industrial sales were modeled from 1979 utilizing Households, a time function, and a dummy variable.

Small classes in Virginia include schools and lighting. School sales are set at a fixed level, while the Lighting sector utilizes the same fixture and average kWh per fixture approach utilized for KU Kentucky Retail Lighting.

The forecast of municipal purchases from KU is developed by analyzing the Company's GWH sales to Transmission customers; Primary customers; the City of Pitcairn, Pennsylvania; and the City of Paris. The Primary Municipal customers are Bardstown, Bardwell, Benham, Falmouth, Madisonville, and Providence. The Transmission Municipal customers are Barbourville, Berea, Corbin, Frankfort, and Nicholasville.

The dependent variable in the sales forecast equation is total gWh sales. Common explanatory variables are heating and/or cooling degree-days, county-level real industrial output, county summarized household forecast, and time. The county-level real industrial output and household forecasts are developed from the KUSTEM database using county specific information and a share-down of regional forecast data.

Demand Forecast

The KU Peak Demand forecast is calculated from the class-level energy forecast, actual and assumed data on class and customer-level load shapes, weather data and losses. The energy, load shape and weather information is combined and customer and class-level demand forecasts are developed using the Hourly Electric Load Model (HELM) developed by EPRI. The annual class demand profiles are summed within HELM to create the system demand forecast. After a native load demand forecast is developed, load impacts associated with KU's Curtailable Service Rider (CSR) are estimated.

The HELM model develops an individual demand forecast for the following load classes; RS, FERS, Commercial, Industrial, Mine Power, Municipals, Lighting, ODP, and major industrial customers. HELM develops an 8760 hourly load forecast for each class, by allocating forecasted sales to each day of the year and assigning daily load shapes to each day, and adds up the class loads to determine the forecasted system demand. HELM creates a library of load shapes that vary by season, groups of months that exhibit similar characteristics, day-type, such as week-day or week-end, and weather. Load shapes are then estimated from load research data. Finally, HELM adds losses to the class level demand and sums the class forecasts to give the system demand forecast. As a final step, the LG&E system hourly load forecast is read into KU's HELM model as a separate class and adjusted for the historical non-coincidence of the two company's peak demands.

7.(7)(d) Treatment and Assessment of Forecast Uncertainty

The essence of the econometric modeling approach, such as the one utilized for producing the 1999 forecasts, is to quantify historical relationships which exist among the target variables to be forecasted and other variables which influence the behavior of the target variables. These quantified relationships are assumed to continue in the future and are used to develop a forecast. However, there are various possible sources of error or uncertainty inherent in this approach.

First, the relationships among the variables may be improperly quantified. A wide range of statistical tests and tracking measures were employed to minimize the possibility of improper quantification.

Second, the underlying structural relationships among the variables may change. If structural change occurs, neither econometric approaches nor other generally accepted forecasting methods would perform well. The best way to deal with this source of uncertainty is to regularly update the forecasting model. KU regularly updates its energy sales, peak demand and customer forecasts on an annual basis in an attempt to reduce this source of uncertainty and error.

A third source of error is that future values of the explanatory variables included in the forecasting models may vary from those used to generate the forecast. To address this uncertainty, the company develops optimistic and pessimistic scenarios to support sensitivity analysis of the various resource acquisition plans being studied. These scenarios are based on controlling future values of the most important variable to the forecast. The WEFA Group provides optimistic and pessimistic forecasts for national variables, which are processed either down to the metro level for LG&E or through the UK/CBER state econometric model and then through the KUSTEM model to produce applicable series for use in KU's energy forecasting models. For uncertainty analysis, the most important variables to the forecast over which the forecaster has control of the predicted values were selected to create the optimistic and pessimistic scenarios.

Quantitative assessment of the likelihood of the variables following their alternative paths depends on the individual vendors. WEFA states in its documentation that it believes there is a 70 percent probability that the economy will most closely resemble the trend, a 15 percent chance that it will resemble the optimistic scenario, and a 15 percent chance that it will resemble the pessimistic case. Table 7. (7) (d)-1 presents the variables chosen by KU for uncertainty analysis and their source. KU has chosen to analyze KU service territory output, personal income, and commercial employment, the KU Kentucky Retail residential customer forecast, and the electric price forecast.

The scenarios as constructed do not directly reflect the inherent degree of uncertainty that electricity usage will have regardless of the path of the economic and demographic drivers. In other words, the variance in sales is due solely to changes in the economic drivers and customer assumptions. However, probabilities of occurrence of each forecast path have been constructed for KU by fitting a probability distribution to the forecast. The forecast is assumed to follow a normal distribution with the Baseline Forecast as the mean. The variance is estimated from historical sales. Ranges defined for each scenario are as follows:

Pessimistic	-	0 to the mid-point of the Pessimistic and Base forecast
Baseline	-	Mid-point between Pessimistic and Baseline forecast to the mid-point between the Baseline and Optimistic Forecast
Optimistic	-	From the mid-point of the Baseline and Optimistic forecasts and beyond

TABLE 7.(7)(d)-1
KU Uncertainty Analysis Variables

	GROWTH SCENARIOS	
VARIABLES	**LOW**	**HIGH**
KU SERVICE TERRITORY VALUE ADDED OUTPUT	KUSTEM Low	KUSTEM High
KU SERVICE TERRITORY PERSONAL INCOME	KUSTEM Low	KUSTEM High
KU SERVICE TERRITORY COMMERCIAL EMPLOYMENT	KUSTEM Low	KUSTEM High
KU SERVICE TERRITORY RESIDENTIAL CUSTOMERS	1999 Forecast	KUSTEM Base
ELECTRIC PRICE	INTERNAL High	INTERNAL Low

The probabilities for each forecast scenario are determined by calculating the cumulative probability of sales falling within the specified range given a normal distribution with mean and variance above. The probabilities of occurrence are calculated in five, ten and fifteen-year increments. Each increment is the probability that the total sales will fall within the range of the pessimistic, optimistic, and baseline forecast and is illustrated in Table 7.(7)(d)-2.

TABLE 7.(7)(d)-2 PROBABILITY OF KU FORECAST OCCURRING

	5-YEAR	10-YEAR	15-YEAR
BASELINE	62.63	78.85	85.87
OPTIMISTIC	4.43	2.33	1.55
PESSIMISTIC	32.94	18.82	12.57

It should be noted that in calculating the cumulative probabilities, the variances are associated with the long run growth trend of the Company. It should also be noted that by becoming directly involved in marketing efforts to achieve the Bulk Power initiatives, and because of the unique load requirements that might be associated with an individual customer, the probability of the Optimistic Forecast occurring may be understated. Although the remaining portions of the Retail Marketing initiatives were not considered fully independent of the Optimistic sales outlook without initiatives, clearly these efforts increase the probability that the sales outlook of KU will track with the Optimistic scenario. If they are successful in addition to the occurrence of optimistic economic and demographic conditions, sales could well track above the Optimistic scenario.

The following tables document the optimistic and pessimistic outlooks for KU:

Table 7.(7)(d)-3
KU Energy Forecast Scenarios Comparison (GWH)

Year	Company Forecast	Optimistic Forecast	Pessimistic Forecast
1999	18,244	18,300	18,152
2000	18,825	18,939	18,680
2001	19,273	19,440	19,083
2002	19,744	19,932	19,546
2003	20,212	20,442	19,948
2004	20,716	20,990	20,372
2005	21,092	21,418	20,723
2006	21,496	21,875	21,074
2007	21,932	22,368	21,449
2008	22,367	22,862	21,827
2009	22,804	23,361	22,204
2010	23,258	23,886	22,605
2011	23,661	24,360	22,944
2012	24,085	24,857	23,304
2013	24,519	25,370	23,676

Table 7.(7)(d)-4
KU Peak Demand Forecast Scenario Comparisons* (MW)

Year	Base Forecast	Optimistic Forecast	Pessimistic Forecast
1999	3,804	3,824	3,791
2000	3,930	3,962	3,906
2001	4,009	4,054	3,976
2002	4,092	4,144	4,059
2003	4,180	4,242	4,134
2004	4,300	4,368	4,232
2005	4,384	4,460	4,310
2006	4,471	4,560	4,385
2007	4,543	4,645	4,445
2008	4,609	4,724	4,501
2009	4,698	4,824	4,576
2010	4,807	4,946	4,672
2011	4,903	5,055	4,752
2012	4,983	5,151	4,820
2013	5,048	5,234	4,874

* Before adjustment for Curtailable Service Rider Load of 28 MW

7.(7)(e) Sensitivity Analysis

1. Changes in prices of electricity and prices of competing fuels

   Price changes have been explicitly addressed in development of the load forecast.

2. Changes in population and economic conditions in the utility's service territory and general region

   Changes in population and economic conditions have been explicitly addressed in development of the load forecast.

3. Development and potential market penetration of new appliances, equipment, and technologies

   The REEPS and COMMEND end-use models provide the capability to model any new appliance or technology that appears likely to have a measurable impact on sales in the foreseeable future.

4. Conservation and load management

   Continuation of existing KU and government sponsored conservation and load management or other demand-side programs as discussed in Section 8.(3)(e) are embedded in the forecast through historical sales data.

7.(7)(f) Research and Development

Research and development efforts in the immediate future will concentrate on identifying "best practices" between the LG&E and KU forecasting systems with the objective of standardizing as many processes as possible. With this approach, the companies can continue to look ahead to enhancements to the forecasting process while maximizing consistency and efficiency.

While the separate tariff structures of KU and LG&E will make complete standardization impractical for the present, the companies are working to develop a common segmentation scheme. While final decisions have not been made, consideration is being given to introducing SIC-code based segmentation to the LG&E data. While useful in developing a more customer focused approach to forecasting, it may require some additional years of history before time dependent regression methods will be able to utilize the data.

In the coming year, the companies will evaluate the methodological differences in the modeling of customers and sales, with the goal of settling on a common approach for as many classes as possible. The final approach may not be identical to either company's methodology before consolidation if enhancements are identified. In particular, KU's experience with the end-use models suggests that innovative thinking needs to be applied to achieve a proper balance between complexity and efficiency in system level energy forecasting. The companies envision a hybrid of econometric and end-use modeling, similar to KU's modeling of the Commercial sector, that attempts to capture factors not present in the historic data while providing statistical rigor for the model diagnostics.

With respect to data, the KUSTEM model utilized by KU has been expanded to include LG&E's service territory. Future forecasts will be more reliant on a common source of local economic outlook information. However, additional information sources may continue to be evaluated in order to provide a comprehensive perspective.

In demand forecasting, the companies intend to emulate the KU use of HELM to generate a class-level demand forecast for LG&E. In addition, the companies intend to thoroughly evaluate the value of a hybrid approach of mixing econometric techniques with the HELM process to capture benefits from each method.

7.(7)(g) Future Development of End-Use Load and Market Data

The companies intend in the coming year to begin work to leverage KU's familiarity with end-use models to LG&E. While LG&E has been pursuing this objective for some time, the desire for standardization where possible has led to the decision to proceed using the framework of the EPRI end-use models similar to KU. As mentioned above, "best practice" analysis may lead to a forecasting system that will not exactly emulate what KU has done in the past.

LG&E is currently in the process of putting in the field a new residential appliance saturation and demographic survey that will be helpful in populating a new model. If resources permit, a conditional demand analysis will be performed on the database to provide updated estimates of appliance usage. All available data from national, regional or local sources will be analyzed to customize the LG&E data as much as possible.

SECTION 8-
RESOURCE ASSESSMENT AND AQUISITION PLAN

8. RESOURCE ASSESSMENT AND ACQUISITION PLAN.

8.(1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.

A principal criterion in the development of this resource plan was to maintain flexibility. The Companies do not plan to commit to a large block of any resource, either supply or demand-side, and be unable to adjust its plan to match changing conditions. The plan, shown year-by-year in Section 5.(4), provides dates for specific resource acquisitions. Resource planning is an ongoing process, and changes in assumptions, technology, market conditions, and the needs of our customers are inevitable. This IRP is part of an ongoing process involving continual assessment of resource options in the context of changing utility needs and new information.

The Companies' resource planning process considers the economics and practicality of available options to meet customer needs. This process involves: 1) establishment of a target reserve margin criterion, 2) assessment of the adequacy of existing generating units and existing purchase power agreements, 3) assessment of potential purchase power suppliers, 4) assessment of demand-side options, 5) assessment of supply-side options, and 6) development of an economic plan from the available resource options.

A study was performed to determine an optimal reserve margin criterion to be used by the Companies. The base case series (base assumptions) from this study indicates that a 12% target reserve margin represents the greatest system reliability under the given set of assumptions. This study further indicated that an optimal target reserve margin in the range of

11% to 14% would provide an adequate and reliable system to meet customers' demand. In the development of the optimal integrated resource plan, the Companies used a reserve margin target of 12% to represent a base case scenario. Additional detail on the development of this criteria is contained in the report titled *Analysis of Reserve Margin Planning Criteria* (October 1999) contained in Volume III, Technical Appendix.

Existing capacity resources are composed of KU and LG&E-owned generating units and two purchase power agreements: Electric Energy Incorporated (EEInc), and Owensboro Municipal Utilities (OMU). The Companies' owned generating units include the two new jointly owned combustion turbines recently completed at the E. W. Brown Plant site. E.W. Brown units 6 and 7 were commissioned on August 11, 1999 and August 8, 1999, respectively. In addition to these two units, three coal-fired units and four combustion turbine units already are in-service at the KU site.

The Companies continually analyze purchase power opportunities through the *Request for Proposal* (RFP) process and through participating in the wholesale marketplace on a real time basis. In February 1999, the Companies issued a Request for Proposal (RFP) for the purpose of procuring peak capacity in order to meet the capacity needs for the summer of 1999 and over the next few years. Based upon the responses to the RFP and the fact that a resource need exists for the year 2000, the Companies have been engaged in ongoing discussions with CT vendors and other companies on available options to meet the peaking requirements beginning in the summer of 2000 and beyond. As a result it appears unlikely that new CT capacity can be purchased and installed before the summer 2000. However, the Companies did begin negotiations with a local vendor for the installation of Inlet Air Cooling (IAC) at the existing E. W. Brown Units 8-11 CTs. The IAC utilizes ice storage to cool the inlet air of the combustion turbines. This capacity addition (approximately 80 MW) was built into the base data as an existing resource enhancement for inclusion in the integrated resource planning analysis.

The technological status, construction aspects, operating costs, and environmental features of various generation plant construction options were reviewed. After screening many technologies, six generation plant construction options and one IPP purchase option were evaluated using resource planning computer models. Along with these supply-side options, three DSM programs were included in the integrated analysis. The optimal integrated resource plan recommends the implementation of all phases of each of the three DSM programs except one phase of the Standby Generation program, the completion of the E. W. Brown CT site with an additional 160 MW combustion turbine, the development of a greenfield CT site, and the installation of a phased constructed combined cycle combustion turbine. Section 8.(5)(c) summarizes in more detail the study.

8.(2) The utility shall describe and discuss all options considered for inclusion in the plan including:

The Companies strategy to acquire additional resources was developed after a thorough evaluation of both demand and supply-side alternatives. This section contains a description and discussion of the options considered during the development of the Companies' optimal integrated resource plan.

8.(2)(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

Generation

The Companies continue to evaluate economic improvements to its generation fleet. Maintenance schedules are coordinated across the entire generation system such that the outages will have the least economic impact to the customers and the Companies.

The Companies continue to perform annual 3-week scheduled maintenance outages on the plants in order to keep them running efficiently through the year. The target six-year cycle for performing major overhauls continues to be successful for the Companies. Routine turbine overhauls restore turbine efficiency to a baseline condition. As inspections reveal potential problems, various boiler and turbine components are repaired or replaced. If upgrades are available they are analyzed and installed when found to be the prudent option.

Efficiency improvements as a result of maintenance practices have been numerous over the past few years. With the combined KU and LG&E generation facilities, the use of best practices across all aspects of the generation business will result in additional improvements to the generation facilities. Several key successes are as follows:

- A Chemical cleaning system has been successful in removing the layers of build-up on the high-pressure turbines at Ghent, recovering lost capacity.
- The use of critical spare parts from LG&E has allowed a KU unit to be back on line in a day instead of weeks or possibly months.
- New or modified coal feeders have been installed at most of the Companies' stations improving the units' ability to respond faster and more reliably throughout the unit's range of operation.
- Precipitator controls have been modified on all Mill Creek and Cane Run units allowing for more efficient energy management of the transformer sets used by the

electrostatic precipitators. Thus, less power is used to achieve the same ash collection.

- Future projects include the installation of soot blower automation at various plants to improve the boiler performance by using closer control of when and where to remove ash build up on the boiler tubes. For example, Ghent Unit 1 is planning to switch from air to steam soot blowers for better use of energy conversion and effectiveness.

During the 1999 spring outage of Cane Run Station Unit 4, modifications were made to the turbine and condenser. Turbine blades were replaced in the last two stages of the low-pressure section due to poor metallurgy integrity. The blade upgrade will improve the heat rate. The units' condenser had over 14% of the cooling water tubes plugged. Typically design margins allow for 10% tube pluggage before unit efficiency is impacted. By replacing the tube bundle, condenser efficiency will be returned to original design conditions. This is accomplished through the even heat transfer distribution between the turbine exhaust steam flow and circulating water flow.

State of the art process control technology application has been, and will continue to be, the major impact to efficiency improvements of the generation stations. New control technologies allow for tighter control of key operating parameters and provide for optimization of integrated systems not previously available with analog controls. New Distributive Control System (DCS) have been installed at Brown 2, Cane Run Units 4, 5, and 6, and Tyrone 3. Green River's DCS system has been upgraded. Plans are underway to have DCS systems installed on Brown 1, Ghent 1 and Mill Creek 1 during the next two years. The control system upgrades provide the operator more information and allow for a quicker response to changes in system demand, which results in a more effective and efficient operation of the unit.

On-going work at Green River to utilize fly ash from the pond has increased the storage capacity of the ash pond. A scrubber has been installed on Ghent 1 to allow for a wider variety of fuel options and to economically comply with the Clean Air Act Amendments of 1990. A valuable by-product of the scrubbing process is gypsum. Gypsum is an essential component in the manufacture of wallboard. A wallboard company is constructing a gypsum wallboard manufacturing facility near the plant. This will allow for beneficial reuse of gypsum, which will increase the life of the Ghent gypsum storage pond. The byproduct process of the Sulfur Dioxide Removal System (SDRS) has been modified at Mill Creek to produce gypsum for wallboard manufacturing. Trimble County is under contract with a wallboard manufacturer and will begin system modifications in the fall of 1999. Contracts exist for the marketing of fly ash from both Mill Creek and Trimble County plants. Contracts are being pursued at other facilities as well. Landfill and ash pond life extension justifies the benefit of marketing fly ash and SDRS byproduct.

LG&E's 1993 Integrated Resource Plan identified the renovation of the Ohio Falls station as a least-cost resource. Since that recommendation, the Companies have initiated an in-depth evaluation of the sustainable long-term generation and modernization needs and opportunities for the facility. This evaluation is considering several economic options and has been an ongoing process throughout 1999. At the time the Companies' 1999 IRP was being prepared, the evaluation of the Ohio Falls Station was not sufficiently complete to incorporate into the development of the plan. Therefore, the renovation of the Ohio Falls station was not included in the Companies' 1999 IRP. As previously stated, the Companies view the filed plan as a snapshot of an ongoing process. Once the current evaluation of the Ohio Falls Station is complete, it will be incorporated into the Companies' ongoing planning process.

In addition to improvements to facilities, Y2K testing and readiness has been a primary focus in 1999. Due to these efforts and upgrades the reliable generation of electricity will continue through the transition to the New Year.

Transmission

The primary purpose of the Companies' transmission system is to reliably transmit electrical energy from company-owned generating sources to native load customers. Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide access to other economic and emergency generating sources for native load customers. The Companies' transmission system is planned to deliver company-owned generator output and purchased generation (economic and/or emergency) to meet projected customer demands and to provide contracted long-term firm transmission services. The transmission system is planned to withstand forced outages of generators and transmission facilities.

The Companies routinely identify transmission construction projects and upgrades required to maintain the adequacy of its transmission system to meet projected customer demands. The construction projects currently identified are included in Volume III, Technical Appendix under the section labeled Transmission Projects.

KU Distribution

Over the past few years, KU has constructed or improved an average of 6-10 distribution substations per year throughout the service territory to serve new customers, improve service reliability, and/or mitigate the effects on customers due to major equipment failures. This trend is expected to continue and several distribution substations (15) have already been targeted for review over the next two years.

In addition to the expected distribution substation improvements, KU distribution personnel continue to plan and construct (on a daily basis) an appropriate level of conductor and distribution transformer additions in order to satisfy the normal service needs of new and existing customers.

LG&E Electric Distribution

LG&E's Electric Distribution System Planning personnel continually review and modify existing facilities and plan additions in future years to achieve the desired service levels to customers. All recommendations are reviewed and discussed annually by an Investment Plan Subcommittee to ensure economical resolution of identified problems that require the minimum practical revenue from our customers.

Specifically, LG&E installed additional capacitors on the distribution system to provide more efficient use of substation transformer capacity and provide power factor correction in support of the transmission system. LG&E plans to continue this practice as studies identify where power factor correction would most benefit the system, taking into account the cost of installation and the resulting savings in capacity.

Also, LG&E modified its distribution planning guidelines to allow substation distribution transformer loading up to 120% of top nameplate rating during contingency conditions. Studies have shown that loading transformers to 120% of top nameplate rating for short periods causes no appreciable loss of life. This reduces the need for installing additional capacity to mitigate the effect on customers when certain facilities are forced out of service. At the same time it allows quick restoration of service to customers during contingency conditions.

8.(2)(b) Conservation and load management or other demand-side programs not already in place;

The integrated resource plan for the Companies includes three DSM programs as options for meeting future customer demand. As with many DSM programs there are uncertainties surrounding implementation of the programs. The expected marketability and penetration of a program is difficult to predict until the program actually begins or experience is gained through a pilot program. The expected level of load reduction can also change due to a number of factors, e.g., efficiency of the air conditioners, or connected load of the standby generator.

Additional detail on this DSM alternative considered for inclusion in the plan is contained in the report titled *Screening of Demand-Side Management (DSM) Options* (September 1999) contained in Volume III, Technical Appendix.

8.(2)(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and

The economics and practicality of supply-side options were carefully examined to develop an integrated resource plan to meet the Companies customer's expected needs. Various supply-side options, including both mature and emerging technologies, were evaluated as part of the integrated resource planning process. Table 8.(2)(c) contains unit data for each supply-side option reviewed. Additional detail on this process is contained in the report titled *Analysis of Supply-Side Technology Alternatives* (August 1999) contained in Volume III, Technical Appendix.

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Table 8.(2)(c)
Generating Technology Option Summary

Jan 1999 $

Unit Type	Fuel Type	Size MW	Cost $/KW	F O&M ($/KW)	V O&M ($/MWH)	Heat Rate (Btu/KWH)	Comm Avail.	Tech. Rating	Design/Cost Rating
Simple Cycle Combust. Turbine			[redacted]						
Combustion Turbine Heavy Duty-80MW	Gas	80	[redacted]	8.43	1.00	12,906	Present	Mature	Preliminary
Combustion Turbine Heavy Duty-110MW	Gas	110	[redacted]	6.49	1.00	13,673	Present	Mature	Preliminary
Combustion Turbine Heavy Duty-160MW	Gas	160	[redacted]	4.97	1.00	11,459	Present	Mature	Preliminary
Brown 5 CT 110MW	Gas	110	[redacted]	6.65	1.00	12,281	Present	N/A	N/A
Brown 5 CT 164MW	Gas	164	[redacted]	5.00	1.00	10,500	Present	N/A	N/A
Brown 5 CT 102MW	Gas	102	[redacted]	7.17	1.00	12,369	Present	N/A	N/A
Brown 5 CT 159MW	Gas	159	[redacted]	5.15	1.00	10,836	Present	N/A	N/A
Brown 5 CT 149MW	Gas	149	[redacted]	5.50	1.00	11,101	Present	N/A	N/A
Aeroderivative Combust. Turbine			[redacted]						
Combustion Turbine Aero- 45MW	Gas	45	[redacted]	12.57	1.00	10,524	Present	Mature	Preliminary
Aeroderivative CT	Gas	100	[redacted]	0.00	4.00	10,362	Present	N/A	N/A
Cascaded Humidified Advanced Turbine			[redacted]						
CT with Cascaded Humidified Advanced Turbine-300MW	Gas	300	[redacted]	13.84	2.16	7,140	Present	Demonstration	Preliminary
Combinded Cycle Combust Turb.			[redacted]						
CT Combined Cycle 2on1 - 330MW	Gas	330	[redacted]	15.58	0.62	7,707	Present	Mature	Preliminary
CT Combined Cycle 2on1 - 470MW	Gas	470	[redacted]	12.23	0.61	7,107	Present	Mature	Preliminary
CT Combined Cycle - 345MW	Gas	345	[redacted]	13.39	0.64	6,954	Present	Demonstration	Preliminary
Pulverized Coal			[redacted]						
Pulverized Coal (LSFO)-500MW	Coal	500	[redacted]	31.34	1.13	9,438	Present	Mature	Preliminary
Pulverized Coal (LSFO)-400MW	Coal	400	[redacted]	38.67	1.02	9,502	Present	Mature	Preliminary
Pulverized Coal (LSFO)-300MW	Coal	300	[redacted]	39.51	1.17	9,507	Present	Mature	Preliminary
Pulverized Coal (LSFO)-200MW	Coal	200	[redacted]	49.78	1.10	9,759	Present	Mature	Preliminary
Pulverized Coal (LSFO)-300MW X 2	Coal	600	[redacted]	31.45	1.08	9,584	Present	Mature	Preliminary
Pulverized Coal Compliance (LSD)- 300MW	Coal	300	[redacted]	34.87	1.06	9,432	Present	Mature	Preliminary
Pulverized Coal Supercritical (LSD)- 300MW	Coal	300	[redacted]	39.48	1.48	9,459	Present	Mature	Preliminary
Pulverized Coal (Advanced LSFO)- 400MW	Coal	400	[redacted]	37.63	1.38	8,637	Present	Mature	Preliminary
Trimble County 2	Coal	495	[redacted]	26.46	0.35	9,900	Present	N/A	N/A
Coal Gasification			[redacted]						
Highly Integrated Coal Gas/Comb Cyc (Entrained)-601MW	Coal	601	[redacted]	45.51	1.08	8,356	Present	Demonstration	Simplified
Int Coal Gas w/ Humid Air Turbine (Entrained Flow)-600MW	Coal	600	[redacted]	42.67	1.24	8,650	Present	Demonstration	Simplified
Int Coal Gas / CAES with Humid Air Turbine-410MW	Coal	410	[redacted]	47.46	0.82	10,320	Present	Demonstration	Preliminary
Int Coal Gas/ Molten Carbonate Fuel Cell 400MW	Coal	400	[redacted]	61.52	4.92	6,860	Present	Demonstration	Simplified
Advanced Int. Coal Gas-460MW	Coal	460	[redacted]	34.28	3.44	7,390	2002	Pilot	Preliminary
Atmospheric Fluid. Bed Combust.			[redacted]						
Atmosph Fluidized Bed (Circulating)-200MW	Coal	200	[redacted]	44.03	2.36	10,025	Present	Commercial	Preliminary
Cane Run 3 Rehab w/ AFBC	Coal	135	[redacted]	41.17	0.97	10,500	Present	N/A	N/A
Pressurized Fluid. Bed Combust.			[redacted]						
Press Fluidized Bed (Bubbling, Non-Reheat)-80MW X 2	Coal	160	[redacted]	60.97	2.46	9,249	Present	Demonstration	Preliminary
Press Fluidized Bed (Bubbling)-350MW	Coal	350	[redacted]	37.57	1.56	9,163	Present	Pilot	Preliminary
Press Fluidized Bed (Bubbling, Supercritic)-340MW	Coal	350	[redacted]	37.26	1.85	8,720	Present	Pilot	Preliminary
Press Fluidized Bed (Circulating, with Reheat)-160MW	Coal	160	[redacted]	51.01	1.95	9,046	Present	Demonstration	Preliminary
Press Fluidized Bed (Circulating, with Reheat)-360MW	Coal	350	[redacted]	36.05	1.91	8,997	Present	Pilot	Preliminary
Press Fluidized Bed (Circulating, Supercritical)-360MW	Coal	350	[redacted]	35.85	2.11	8,569	Present	Pilot	Preliminary
Foster Wheeler Advanced PFB (Circulating)-688MW	Coal	688	[redacted]	30.55	4.48	7,650	2002	Pilot	Preliminary
Option 13	Coal	500	[redacted]	9.60	1.65	10,000	Present	N/A	N/A
Fuel Cells			[redacted]						
Phosphoric Acid Fuel Cell-2.5MW	Gas	3	[redacted]	538.51	2.38	9,350	Present	Demonstration	Simplified
Molten Carbonate Fuel Cell-100MW	Gas	10	[redacted]	126.80	2.07	5,600	2002	Demonstration	Simplified
Solid Oxide Fuel Cell-100MW	Gas	25	[redacted]	67.78	0.04	6,172	2002	Demonstration	Simplified
Battery Energy Storage			[redacted]						
Lead Acid Battery Storage(1 hr)-20MW	Charging	20	[redacted]	1.71	8.12	@ 1.31	Present	Mature	Preliminary
Advanced Battery (3 hr)-20MW	Charging	20	[redacted]	0.49	7.05	@ 1.14	Present	Pilot	Goal
Advanced Battery (5 hr)-20MW	Charging	20	[redacted]	1.07	5.13	@ 1.10	Present	Pilot	Goal
Compress Air Energy Storage			[redacted]						
Compressed Air Energy (Salt Cavern) -350MW	Gas	350	[redacted]	5.73	0.99	# 0.79 + 3991	Present	Commercial	Actual
Compressed Air Energy w/ Humid Air Turbine-350MW	Gas	350	[redacted]	5.04	1.00	# 0.46 + 6156	Present	Pilot	Preliminary
Wind Turbines			[redacted]						
Wind Turbines-Variable Speed-50x750kw	Wind	37	[redacted]	18.61	0.00	-	Present	Demonstration	Simplified
Wind Turbines-High Prod Volume-143x350kw	Wind	50	[redacted]	25.91	0.00	-	Present	Demonstration	Simplified
Wind Turbines-Class 4 Speed-50x750kw	Wind	38	[redacted]	24.47	0.00	-	2000	Commercial	Goal
Geothermal			[redacted]						
Geothermal: Dual Flash Brine, Air Cooled-24MW	Brine	24	[redacted]	45.14	0.00	29,050	Present	Demonstration	Preliminary
Pumped Hydro			[redacted]						
Pumped Hydro Energy Storage-350MW X 3	Charging	1050	[redacted]	4.60	4.60	@ 1.36	Present	Mature	Actual
Solar Photovoltaic - 2000 Technology			[redacted]						
Solar Photovoltaic:Flat Plate-10x5MW	Solar	50	[redacted]	9.07	0.00	-	2000	Pilot	Goal
Solar Photovoltaic:One Axis Tracking Flat Plate-10x5MW	Solar	50	[redacted]	9.80	0.00	-	2000	Pilot	Goal
Solar Photovoltaic:Fresnel Lens High Concen.-10x5MW	Solar	50	[redacted]	42.25	0.00	-	2000	Pilot	Goal
Solar Thermal			[redacted]						
Solar Thermal Trough/Gas Hybrid-200MW	Solar	200	[redacted]	26.83	3.19	-	Present	Mature	Preliminary
Municipal Solid Waste			[redacted]						
Municipal Solid Waste: Mass Burn-40MW	Refuse-MSW	40	[redacted]	208.48	25.91	16,864	Present	Commercial	Simplified
Municipal Solid Waste: Refuse Der.-40MW	Refuse-RDF	40	[redacted]	246.51	25.80	16,958	Present	Commercial	Simplified
Municipal Solid Waste: Tire-30MW	RefuseTire	30	[redacted]	132.20	3.60	12,737	Present	Commercial	Simplified
Bio Mass			[redacted]						
Bio Mass: Wood-Fired Stoker Boiler-50MW	Biomass	50	[redacted]	69.90	2.67	14,310	Present	Commercial	Simplified
Bio Mass: Whole Tree-100MW	Whole Tree	100	[redacted]	51.40	1.75	10,979	Present	Pilot	Goal
Superconducting Magnetic Energy Storage			[redacted]						
Super Conducting Magnetic Energy Storage (2 hr)-500MW	Charging	500	[redacted]	5.14	4.11	@ 1.08	2000	Pilot	Goal
Hydroelectric Power			[redacted]						
IPP Hydro	Water	160	[redacted]	30.18	0.00	-	Present	N/A	N/A
Ohio Falls 9&10	Water	34	[redacted]	8.91	0.00	-	Present	N/A	N/A
Other			[redacted]						
Cane Run 3 Rehab w/ Natural Gas	Gas	135	[redacted]	41.17	0.00	11,100	Present	N/A	N/A
IAC at Brown 8-11	Gas	86	[redacted]	0.93	1.48	# 0.38 +11,651	Present	N/A	N/A

\# -->KWH Input plus (Btu) Fuel Input for every 1.0 KWH output
@-->KWH Input for every 1.0 KWH output
N/A --> Not Available

EPRI based Technology Rating Classifications

Mature - More than five commercial units.
Demonstration - Concept verified by integrated demonstration unit.
Pilot - Concept verified by small pilot facility.

EPRI based Design and Cost Estimate Rating Classifications

Actual	Data on detailed process and designs of existing units.
Detailed	Detailed process design.
Preliminary	Preliminary process design.
Simplified	Simplified process design.
Goal	Technical design/cost from literature data.

8.(2)(d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.

From time to time, the Companies receive inquiries from prospective Qualifying Facilities (QFs), typically less than 5 megawatts. Currently there are two such facilities operating within the service areas of the Companies. One facility currently operating within KU's service area is a small hydro facility of less than 0.06 megawatts. The other facility is connected to the LG&E system and generates power for its own use, thus reducing its energy purchases from the Companies. It does not reduce the capacity required to serve this customer. The Companies have corresponded in the past with a firm that might offer both capacity and energy from a facility that would burn a renewable fuel. Also, the Companies frequently provide information, including technical requirements, contracts, and buy-back rates, to firms that are apparently considering the Companies' service territory as the location of a PURPA facility

The Companies receive inquiries from Independent Power Producers (IPPs). The IPPs typically have an interest in projects based on combined-cycle or base-load technology and not simple-cycle technology. The Companies have and will continue to evaluate all bid proposals received with the goal of determining least-cost generation resources. Each proposal received will be evaluated on a case-by-case basis and if appropriate will be incorporated into the Companies list of supply-side options for future evaluations. As discussed in the supply-side screening analysis included in the report titled *Analysis of Supply-Side Technology Alternatives* (August 1999) contained in Volume III, Technical Appendix, the Companies received a proposal from a run-of-the river hydroelectric IPP project.

Recently, Dynegy Inc. announced plans to build a 324 MW gas-fired merchant plant in Buckner, Kentucky, and a 500 MW gas-fired merchant plant in Lawrence County, Kentucky.

Enron Corp. has also announced plans to build a 500 MW gas-fired merchant plant in Calvert City, Kentucky and a 500 MW gas-fired merchant plant in Knox County, Indiana. Location of Exempt Wholesale Generators (EWGs) near or within the Companies' service territory is expected to continue as the deregulated wholesale power marketplace evolves. The Companies have included in the past and will include in the future both entities, as well as other projects of this nature, in any Requests for Proposals for purchased power that may be issued by the Companies.

The Commonwealth of Kentucky has a significant amount of coal supplies for use in the generation of electricity. There may be opportunities in the future for the use of coal in a generating facility that utilizes a mine/mouth operation for the supply of fuel to the facility. This type of operation would provide significant fuel cost savings over a typical supply-delivery chain utilized in the majority of existing facilities. However, the capital cost of a coal-based technology would need to be significantly lower than the current estimates for such an option to become economically viable even with the fuel cost savings. Currently the Companies have not received firm offers from this type of IPP facility. In the event that the Companies do receive offers from such facilities in the future, it will be included in the Companies planning process as a potential resource.

8.(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.

8.(3)(a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.

Following is a map showing the Companies' existing generating and transmission facilities. The type and capacity of the generating plants are indicated in the upper left-hand legend. The voltage rating of the various transmission lines and the symbol for interconnection points are indicated in the lower right-hand legend. A complete listing showing interconnection points in Table 8.(3)(a) is inclusive of location and capability. Transfer capabilities are primarily limited to the capability as shown in Table 8.(3)(a). Other factors that limit transactions come into play depending on the time period, the transaction and the parties involved. Case-by-case analysis is necessary in such situations.

Table 8.(3)(a)

LG&E Energy Corp.

Interconnections with Other Companies

9/1/1999

Interconnection	kV	Limiting Company	Rating (MVA) Summer Normal	Summer Emergency	Winter Normal	Winter Emergency	By Letter Dated
AEP							
Kenton to Hillsboro	138	KU & AEP	164	191	191	191	9/20/93
Rodburn to Morehead	69	KU	33	38	33	43	3/27/96
			197	229	224	234	
BRECC							
Green River to Wilson	161	KU	446	499	446	499	11/07/97
*Cloverport to Hardinsburg**	138	BRECC	200	224	200	224	
*Hardinsburg to Hardinsburg**	138	BRECC	200	224	200	224	2/11/87
*The net flow on these two interconnections is limited to 200/224 MVA.			846	947	846	947	
CINERGY							
Ghent to Batesville	345	KU	598	717	598	717	11/12/92
Ghent to Speed	345	KU	598	717	598	717	10/05/87
Beargrass/Northside to Jeffersonville	138	CIN	246	246	287	287	
Ghent to Fairview	138	KU & CIN	227	382	304	382	4/23/87
Northside to Speed	138	CIN	287	287	287	287	
Paddys West to Gallagher	138	CIN	382	382	382	382	
			2338	2731	2456	2772	
DOE							
Grahamville to C-33A	161	KU & DOE	307	335	335	335	11/16
			307	335	335	335	
EKPC							
Blue Lick to Bullit Co.	161	LG&E	240	240	240	240	
Delvinta to Beattyville/Powell County	161	EKPC & KU	78	78	167	167	2/17/97
Delvinta to Tyner	161	EKPC & KU	78	78	167	201	2/17/97
Elihu to Cooper	161	KU	239	279	279	279	3/31/92
Lebanon to Marion County	161/138	EKPC	135	167	167	167	2/26/87
Beattyville to Delvinta/Powell County	161/69	KU	56	62	56	70	1/03/94
Pittsburg to Laurel County/Tyner	161/69	KU	112	120	112	120	1/03/94
Taylor County to Green County/Marion County	161/69	KU	56	62	56	70	1/03/94
Fawkes to Fawkes	138	KU & EKPC	263	287	287	287	8/29/96
Ghent to Gallatin County	138	KU & EKPC	227	280	287	287	3/06/90
Goddard to Goddard	138	KU	143	191	143	191	10/5
Kenton to Spurlock	138	EKPC	227	280	280	280	1/03/94
Kenton to Spurlock	138	EKPC	227	280	280	280	1/03/94
Loudon Avenue to Avon	138	KU	205	252	274	287	2/13/97
Rodburn to Skaggs	138	EKPC	90	120	111	137	2/26/87
Bardstown/Etown to Nelson County	138/69	EKPC	143	143	143	143	2/26/87
Bonnieville to Bonnieville	138/69	EKPC	44	59	55	68	5/12/92
Boonesboro North to Avon/Dale	138/69	KU	93	102	93	116	1/03/94
Ghent/Scott County to Owen County	138/69	EKPC	143	143	143	143	2/26/87
Adams to Penn	69	EKPC	30	30	42	42	3/31/92
Beattyville to Beattyville	69	EKPC	72	72	72	72	2/26/87
Bardstown Industrial to East Bardstown	69	KU & EKPC	50	50	72	72	10/5
Bonds Mill to North Springfield	69	EKPC	37	40	51	54	2/17/97
Bromley to Owen County	69	KU	57	57	72	86	3/31/92
Carntown to Bracken County	69	KU	42	42	50	60	3/07/96
Carrollton to Hunters Bottom	69	EKPC	42	42	60	60	4/01/92
Clay Village to Clay Village	69	EKPC	36	36	36	36	10/17
Cynthiana Switching to Renaker	69	KU & EKPC	57	57	72	72	3/07/96
Eastview to Stephensburg	69	KU & EKPC	42	42	54	54	2/16/98
Elizabethtown to Kargle	69	KU & EKPC	57	69	72	86	5/12/92
Elizabethtown to Tharp	69	KU & EKPC	57	69	72	72	2/26/87
Farley to South Corbin	69	KU & EKPC	53	53	72	72	2/26/87
Fawkes to Hickory Plain	69	EKPC	45	54	62	68	3/07/96
Ferguson South to Somerset*	69	KU & EKPC	83	83	108	108	2/16/98
Greensburg to Green County	69	KU & EKPC	54	54	54	54	3/31/92
Hodgenville to Hodgenville	69	KU & EKPC	27	27	72	72	10/05/87
Hopewell to Laurel County	69	KU	72	72	72	72	3/07/96
Kenton to Murphysville	69	EKPC	72	72	72	72	10/05/87
New Haven to Hodgenville	69	KU & EKPC	35	35	72	72	1/03/94
Rogersville to Vine Grove	69	KU	72	72	72	72	4/27/90
Sardis to Murphysville	69	KU & EKPC	39	47	50	50	3/31/92
Sharon to Bracken County	69	KU	28	28	48	57	10/05/87
Somerset South to Somerset*	69	KU	45	45	68	68	2/16/98
Springfield to North Springfield	69	EKPC	19	19	36	36	8/29/96
Union Underwear to Sewellton	69	KU	32	32	61	61	3/07/96
*The net flow on these two interconnections is limited to 96 MVA.			4054	4522	4984	5233	

Table 8.(3)(a)

LG&E Energy Corp.

Interconnections with Other Companies

9/1/1999

Interconnection	kV	Limiting Company	Rating (MVA) Summer Normal	Summer Emergency	Winter Normal	Winter Emergency	By Letter Dated
OMU							
Hardin County to Smith	345	OMU	275	308	275	308	2/11/87
Green River Steel to Smith	138	KU & OMU	241	241	287	287	10/05/87
Green River Steel to Smith	69	KU	72	86	72	100	10/05/87
			588	635	634	695	
OVEC							
Trimble County to Clifty Creek	345	LG&E	1195	1195	1195	1195	
Carrollton to Clifty Creek	138	KU & OVEC	181	191	191	191	3/31/92
Northside to Clifty Creek	138	LG&E	96	96	96	96	
			1472	1482	1482	1482	
SIGE							
Cloverport to Newtonville	138	LG&E	143	143	143	143	
			143	143	143	143	
TVA							
Pocket North to Phipps Bend	500	KU	693	693	693	693	2/11/87
Livingston County to Calvert City	161	TVA	223	223	263	263	2/22/93
Livingston County to Kentucky Dam	161	KU & TVA	290	298	335	335	2/22/93
Paddys Run to Summershade	161	LG&E	240	240	240	240	
Pineville Switching to Pineville	161	KU	187	187	319	335	3/27/96
Paducah South to Kentucky Dam	69	KU	20	20	41	41	3/27/96
Paducah South/Princeton to Kentucky Dam	69	KU & TVA	54	54	72	72	3/27/96
			1707	1715	1963	1979	

8.(3)(b) A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility:

1. Plant name;
2. Unit number(s);
3. Existing or proposed location;
4. Status (existing, planned, under construction, etc.);
5. Actual or projected commercial operation date;
6. Type of facility;
7. Net dependable capability, summer and winter;
8. Entitlement if jointly owned or unit purchase;
9. Primary and secondary fuel types, by unit;
10. Fuel storage capacity;
11. Scheduled upgrades, deratings, and retirement dates;
12. Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars.
a. Capacity and availability factors;
b. Anticipated annual average heat rate;
c. Costs of fuel(s) per millions of British thermal units (MMBtu);
d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity);
e. Variable and fixed operating and maintenance costs;
f. Capital and operating and maintenance cost escalation factors;
g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).

The requested information can be found in the tables on the following pages.

Table 8.(3)(b)

Kentucky Utilities Company / Louisville Gas & Electric Company

Existing and Planned Electric Generating Facilities

1	2	3	4	5	6	7		8		9	10	11
Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW) Winter	Summer	Entitlement KU	LGE	Fuel Type	Fuel Storage Capacity	Scheduled Upgrades Derates, Retirements
Cane Run	4	Louisville	Existing	1962	Steam	155	155		100%	Coal	250,000 Tons	None
	5			1966		168	168					
	6			1969		240	240					
	11			1968	Turbine	19	16			Gas/Oil	100,000 Gals	
Dix Dam	1-3	Burgin	Existing	1925	Hydro	24	24	100%		Water	None	None
E. W. Brown	1	Burgin	Existing	1957	Steam	107	104	100%		Coal	360,000 Tons	None
	2			1963		170	168					
	3			1971		442	439					
	6			1999	Turbine	181	164	62%	38%	Gas/Oil	2,200,000 Gals	
	7			1999		181	164					
	8			1995		135	110	100%				Uprate-2000
	9			1994		135	110					
	10			1995		135	110					
	11			1996		135	110					
Ghent	1	Ghent	Existing	1974	Steam	494	483	100%		Coal	310,000 Tons	None
	2			1977		501	492				1,000,000 Tons	Derate - 2003
	3			1981		501	493					None
	4			1984		503	494					
Green River	1	Central City	Existing	1950	Steam	29	26	100%		Coal	170,000 Tons	None
	2			1950		30	27					
	3			1954		72	71					
	4			1959		107	103					
Haefling	1	Lexington	Existing	1970	Turbine	18	15	100%		Gas/Oil	630,000 Gals	None
	2			1970		18	15					
	3			1970		18	15					
Lock 7	1-3	Burgin	Existing	1927	Hydro	Run of River Plant		Lease		Water	None	None
Mill Creek	1	Louisville	Existing	1972	Steam	303	303		100%	Coal	750,000 Tons	None
	2			1974		301	301					
	3			1978		386	386					
	4			1982		490	480					
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	Run of River Plant			100%	Water	None	Under Study
Paddy's Run	11	Louisville	Existing	1968	Turbine	19	17		100%	Gas	None	None
	12			1968		32	26					
Pineville	3	Four Mile	Existing	1951	Steam	35	34	100%		Coal	7,000 Tons	None
Tyrone	1	Versailles	Existing	1947	Steam	30	27	100%		Oil	514,000 Gals	None
	2			1948		33	31					
	3			1953		72	71			Coal	30,000 Tons	
Trimble County	1	Near Bedford	Existing	1990	Steam	495	495		75%	Coal	500,000 Tons	None
Waterside	7	Louisville	Existing	1964	Turbine	20	17		100%	Gas	None	None
	8			1964		19	16					
Zorn	1	Louisville	Existing	1969	Turbine	18	16		100%	Gas	None	None
Future Units												
E. W. Brown	5	Burgin	Planned	2001	Turbine	185	160	Unknown		Gas	None	None
Combined Cycle 1	PH1	Unknown	Planned	2011	Combined Cycle	185	160	Unknown		Gas	None	None
	PH2			2012		185	160					
	PH3			2013		150	150					
Greenfield CT	1	Unknown	Planned	2001	Turbine	185	160	Unknown		Gas	None	None
	2			2001		185	160					
	3			2002		185	160					
	4			2004		185	160					
	5			2005		185	160					
	6			2006		185	160					
	7			2007		185	160					
	8			2008		185	160					
	9			2009		185	160					
	10			2010		185	160					

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 1

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	56.8	54.4	61.2	60.8	61.1	61.3	61.2	61.4	55.6	62.3	63.2	63.2	64.0	64.0	65.2	58.9
	Availability Factor (%)	91.6	80.2	89.5	89.7	89.8	90.0	90.0	90.0	80.8	90.0	90.0	90.0	90.0	90.0	90.0	80.8
b	**Average Heat Rate (Btu/kWH)**	10,851	10,647	10,643	10,648	10,646	10,645	10,646	10,644	10,638	10,635	10,626	10,626	10,619	10,618	10,608	10,604
c	**Cost of Fuel ($/MBTU)**	1.13	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 2

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	70.9	49.7	51.0	45.5	50.7	51.5	50.2	51.7	52.8	53.9	50.1	55.7	56.6	57.5	59.3	60.1
	Availability Factor (%)	94.3	89.6	89.3	80.0	88.9	88.7	88.7	88.7	88.7	88.7	79.6	88.7	88.7	88.7	88.7	88.7
b	Average Heat Rate (Btu/kWH)	9,955	10,252	10,233	10,237	10,234	10,222	10,240	10,221	10,207	10,194	10,173	10,174	10,165	10,155	10,137	10,131
c	Cost of Fuel ($/MBTU)	1.13	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 3

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	58.7	39.1	40.9	41.8	43.7	45.0	40.0	45.3	46.2	47.0	48.8	48.8	45.6	50.7	52.4	53.3
	Availability Factor (%)	83.4	80.4	82.6	84.7	86.8	89.0	79.8	89.0	89.0	89.0	89.0	89.0	79.8	89.0	89.0	89.0
b	Average Heat Rate (Btu/kWH)	10,158	10,529	10,515	10,515	10,501	10,495	10,505	10,491	10,475	10,462	10,435	10,434	10,406	10,408	10,384	10,372
c	Cost of Fuel ($/MBTU)	1.13	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 6

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**		0.8	5.5	6.9	10.0	9.5	8.4	8.9	9.4	11.7	16.2	21.0	23.9	23.5	31.8	21.4
	Availability Factor (%)		90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4
b	**Average Heat Rate (Btu/kWH)**		10,921	11,989	12,256	12,440	12,412	12,383	12,243	12,153	12,176	12,170	12,300	12,261	12,223	12,236	12,107
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 7

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**		2.7	8.0	9.0	10.7	13.3	9.0	13.0	14.2	20.2	25.7	25.2	28.9	29.1	33.3	30.5
	Availability Factor (%)		90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4
b	**Average Heat Rate (Btu/kWH)**		12,086	12,017	12,228	12,293	12,405	12,235	12,300	12,236	12,341	12,295	12,244	12,225	12,201	12,106	12,199
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 8

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	6.8	4.0	3.1	0.8	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2
	Availability Factor (%)	85.5	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4
b	Average Heat Rate (Btu/kWH)	12,608	12,941	12,993	12,443	12,453	12,455	12,444	12,450	12,437	12,437	12,443	12,427	12,437	12,435	12,433	12,417
c	Cost of Fuel ($/MBTU)	2.80	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 9

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	7.3	3.4	2.7	0.5	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Availability Factor (%)	72.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4
b	Average Heat Rate (Btu/kWH)	12,737	13,040	13,093	12,458	12,467	12,469	12,458	12,471	12,449	12,449	12,461	12,442	12,440	12,440	12,449	12,434
c	Cost of Fuel ($/MBTU)	2.82	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 10

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	6.7	3.0	1.0	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Availability Factor (%)	80.7	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4
b	Average Heat Rate (Btu/kWH)	12,789	13,138	12,442	12,476	12,476	12,474	12,467	12,481	12,462	12,464	12,474	12,459	12,460	12,459	12,469	12,445
c	Cost of Fuel ($/MBTU)	2.83	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 11

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	3.9	1.1	0.7	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Availability Factor (%)	62.2	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4	90.4
b	Average Heat Rate (Btu/kWH)	12,803	12,511	12,452	12,494	12,491	12,495	12,486	12,498	12,483	12,487	12,491	12,477	12,479	12,481	12,468	12,458
c	Cost of Fuel ($/MBTU)	2.88	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

CANE RUN 4

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	64.8	50.1	52.0	54.7	57.5	53.3	50.0	49.8	53.4	60.4	59.7	60.3	50.7	49.1	54.1	47.9
	Availability Factor (%)	86.3	80.7	82.6	88.0	86.3	91.8	88.1	80.2	88.1	91.8	88.1	88.1	91.8	88.1	91.8	80.8
b	Average Heat Rate (Btu/kWH)	10,556	10,874	10,859	10,870	10,797	10,948	10,975	10,909	10,872	10,809	10,780	10,771	11,007	10,997	10,932	10,922
c	Cost of Fuel ($/MBTU)	1.11	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

CANE RUN 6

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	62.3	41.3	50.0	53.3	52.4	55.8	54.0	55.2	59.5	60.1	63.0	64.9	51.4	46.8	55.9	57.3
	Availability Factor (%)	77.9	70.6	75.8	82.8	76.2	86.9	90.5	86.9	90.5	86.9	86.9	88.7	88.2	79.6	88.7	90.5
b	Average Heat Rate (Btu/kWH)	10,248	10,495	10,362	10,386	10,318	10,385	10,465	10,398	10,361	10,310	10,267	10,266	10,490	10,483	10,406	10,399
c	Cost of Fuel ($/MBTU)	1.12	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

CANE RUN 5

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	64.0	64.7	53.5	53.1	63.8	62.0	58.1	62.7	61.8	59.5	65.2	67.1	68.9	70.7	71.9	71.1
	Availability Factor (%)	77.8	79.9	77.1	74.0	84.4	89.9	86.3	89.9	86.3	79.1	84.0	87.6	86.3	85.8	89.9	86.3
b	Average Heat Rate (Btu/kWH)	10,683	10,428	10,626	10,576	10,505	10,627	10,663	10,610	10,576	10,510	10,486	10,479	10,436	10,433	10,406	10,399
c	Cost of Fuel ($/MBTU)	1.09	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

CANE RUN 11

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	1.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	85.7	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
b	Average Heat Rate (Btu/kWH)	14,881	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	Cost of Fuel ($/MBTU)	3.12	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GHENT 1

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	81.7	85.0	76.9	86.3	87.3	78.7	88.0	88.0	87.9	78.9	88.0	88.0	88.0	87.9	87.9	79.0
	Availability Factor (%)	85.2	86.0	77.8	87.5	88.2	79.8	88.9	88.9	88.9	79.8	88.9	88.9	88.9	88.9	88.9	79.8
b	**Average Heat Rate (Btu/kWH)**	10,285	10,172	10,173	10,174	10,171	10,175	10,171	10,171	10,172	10,173	10,171	10,170	10,171	10,171	10,171	10,170
c	**Cost of Fuel ($/MBTU)**	0.90	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GHENT 2

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	65.0	48.7	47.3	49.3	50.6	71.7	80.4	78.4	79.3	80.6	81.6	73.1	82.9	83.1	84.3	85.4
	Availability Factor (%)	89.9	89.9	86.0	89.4	89.2	79.9	89.0	89.0	89.0	89.0	89.0	79.9	89.0	89.0	89.0	89.0
b	Average Heat Rate (Btu/kWH)	9,988	10,224	10,218	10,217	10,204	10,281	10,279	10,287	10,283	10,278	10,274	10,275	10,269	10,269	10,265	10,261
c	Cost of Fuel ($/MBTU)	1.22	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GHENT 3

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	70.9	47.9	51.9	51.0	46.5	47.9	46.8	48.5	50.7	52.1	49.1	54.7	61.6	62.6	64.7	66.0
	Availability Factor (%)	87.5	87.3	90.9	89.1	79.9	89.0	89.0	89.0	89.0	89.0	79.8	89.0	89.0	89.0	89.0	89.0
b	**Average Heat Rate (Btu/kWH)**	10,340	10,739	10,689	10,686	10,665	10,762	10,793	10,746	10,692	10,658	10,602	10,602	10,476	10,458	10,428	10,407
c	**Cost of Fuel ($/MBTU)**	1.22	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GHENT 4

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	72.6	53.0	58.2	50.5	59.2	53.5	52.0	54.5	50.7	58.7	60.6	61.0	67.9	68.5	62.9	71.4
	Availability Factor (%)	94.6	85.6	91.0	80.0	89.0	89.0	89.0	89.0	79.8	89.0	89.0	89.0	89.0	89.0	79.8	89.0
b	Average Heat Rate (Btu/kWH)	10,269	10,339	10,310	10,321	10,277	10,365	10,392	10,348	10,316	10,283	10,257	10,251	10,168	10,162	10,146	10,132
c	Cost of Fuel ($/MBTU)	1.22	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREEN RIVER 1

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	19.4	3.6	6.3	6.6	7.0	7.3	7.3	7.4	7.5	7.6	7.7	9.6	11.6	11.6	11.6	11.6
	Availability Factor (%)	90.0	73.0	77.0	81.1	85.1	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2
b	**Average Heat Rate (Btu/kWH)**	14,890	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	**Cost of Fuel ($/MBTU)**	1.05	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREEN RIVER 2

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	17.3	1.7	3.9	5.0	6.1	7.3	7.3	7.3	7.4	7.5	7.6	9.6	11.6	11.6	11.6	9.6
	Availability Factor (%)	91.1	33.7	47.6	61.5	75.3	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2
b	Average Heat Rate (Btu/kWH)	17,434	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	Cost of Fuel ($/MBTU)	1.05	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREEN RIVER 3

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	58.2	62.7	45.3	45.6	41.4	46.6	46.5	46.9	47.7	48.2	44.4	49.6	50.4	50.6	52.3	52.7
	Availability Factor (%)	94.9	84.2	87.4	88.2	80.0	90.0	90.0	90.0	90.0	90.0	80.8	90.0	90.0	90.0	90.0	90.0
b	**Average Heat Rate (Btu/kWH)**	12,258	12,005	12,582	12,590	12,589	12,586	12,589	12,572	12,540	12,522	12,476	12,469	12,442	12,434	12,379	12,364
c	**Cost of Fuel ($/MBTU)**	1.05	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREEN RIVER 4

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	65.1	41.4	43.5	45.0	47.1	43.2	48.1	48.9	49.7	50.4	51.8	46.7	52.9	53.2	54.9	55.4
	Availability Factor (%)	92.9	77.9	81.0	84.0	87.0	80.8	90.0	90.0	90.0	90.0	90.0	80.8	90.0	90.0	90.0	90.0
b	Average Heat Rate (Btu/kWH)	11,265	11,298	11,278	11,282	11,265	11,282	11,283	11,258	11,234	11,216	11,176	11,170	11,146	11,138	11,097	11,086
c	Cost of Fuel ($/MBTU)	1.05	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

HAEFLING 1,2,3

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	1.7	0.6	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	93.3	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9
b	**Average Heat Rate (Btu/kWH)**	18,110	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	**Cost of Fuel ($/MBTU)**	3.65	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

MILL CREEK 1

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	58.6	49.9	60.0	54.3	66.7	56.7	58.0	61.1	61.4	66.8	61.1	66.5	71.8	69.0	71.6	75.4
	Availability Factor (%)	74.8	76.7	85.6	76.7	88.9	86.9	88.7	88.2	86.9	90.5	79.6	86.9	90.5	86.9	86.9	90.5
b	Average Heat Rate (Btu/kWH)	10,351	10,707	10,653	10,647	10,606	10,703	10,705	10,661	10,646	10,616	10,592	10,593	10,571	10,571	10,549	10,541
c	Cost of Fuel ($/MBTU)	1.07	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

MILL CREEK 2

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	55.5	61.8	56.3	62.2	62.7	67.4	62.4	67.1	71.2	68.9	64.0	74.7	73.5	74.0	79.3	76.6
	Availability Factor (%)	70.6	87.0	74.8	83.4	78.0	90.5	86.9	86.3	94.7	86.9	79.6	90.5	86.9	86.9	90.5	86.9
b	Average Heat Rate (Btu/kWH)	10,655	10,874	10,821	10,828	10,762	10,829	10,863	10,817	10,799	10,773	10,761	10,740	10,720	10,715	10,693	10,688
c	Cost of Fuel ($/MBTU)	1.07	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

MILL CREEK 3

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	71.7	61.2	75.0	79.9	72.7	82.1	84.6	83.0	85.3	86.0	85.0	88.3	78.2	85.4	86.1	90.0
	Availability Factor (%)	81.4	73.3	81.7	86.9	78.0	86.9	90.5	86.9	86.3	90.5	86.9	90.5	79.6	86.9	86.9	90.5
b	Average Heat Rate (Btu/kWH)	10,270	10,499	10,388	10,384	10,368	10,365	10,352	10,340	10,334	10,324	10,315	10,317	10,311	10,309	10,300	10,297
c	Cost of Fuel ($/MBTU)	1.07	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

MILL CREEK 4

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	64.0	66.3	74.2	83.3	82.4	83.5	87.8	77.4	84.9	84.8	86.7	85.5	85.8	89.4	78.9	86.1
	Availability Factor (%)	76.1	76.2	79.3	87.7	85.7	87.1	90.8	79.8	87.1	86.6	88.4	87.1	87.1	90.8	79.8	87.1
b	**Average Heat Rate (Btu/kWH)**	10,433	10,295	10,217	10,203	10,188	10,192	10,184	10,181	10,176	10,171	10,168	10,170	10,166	10,166	10,163	10,162
c	**Cost of Fuel ($/MBTU)**	1.06	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

PADDYS RUN 11

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	2.3	0.7	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	75.5	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
b	Average Heat Rate (Btu/kWH)	14,886	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	Cost of Fuel ($/MBTU)	2.94	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

PADDYS RUN 12

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	2.4	0.7	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	68.6	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
b	Average Heat Rate (Btu/kWH)	14,886	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	Cost of Fuel ($/MBTU)	2.94	[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

PINEVILLE 3

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	32.9	9.2	12.2	10.8	15.2	18.0	11.9	16.6	18.5	22.2	29.0	29.8	32.9	33.3	30.5	37.9
	Availability Factor (%)	96.8	89.2	92.2	91.1	89.9	76.5	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7	76.5	88.7
b	Average Heat Rate (Btu/kWH)	14,308	13,952	13,978	13,981	14,020	14,037	13,998	14,014	14,001	14,009	14,006	14,005	13,998	13,997	13,977	14,005
c	Cost of Fuel ($/MBTU)	1.03	[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

TRIMBLE COUNTY

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	77.8	91.1	74.4	75.8	78.7	66.8	72.6	83.3	80.1	81.5	86.1	82.7	86.0	81.8	85.2	84.6
	Availability Factor (%)	84.7	93.8	86.3	88.4	88.7	79.8	87.2	90.8	87.2	87.2	90.8	87.2	89.0	85.3	87.2	84.8
b	Average Heat Rate (Btu/kWH)	9,868	10,050	10,074	10,075	10,068	10,081	10,081	10,061	10,061	10,057	10,055	10,055	10,052	10,053	10,049	10,048
c	Cost of Fuel ($/MBTU)	0.93	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

TYRONE 1

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	0.4	0.6	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	99.8	93.0	91.9	93.0	90.9	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7
b	Average Heat Rate (Btu/kWH)	37,725	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	Cost of Fuel ($/MBTU)	3.22	[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

TYRONE 2

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	0.3	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	99.8	39.8	52.0	64.2	76.5	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7
b	Average Heat Rate (Btu/kWH)	39,393	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	Cost of Fuel ($/MBTU)	3.22	[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

TYRONE 3

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	33.5	8.2	11.0	10.0	13.7	15.9	11.2	15.6	17.8	22.3	28.7	29.5	32.6	32.7	36.5	37.5
	Availability Factor (%)	96.1	89.4	91.8	92.4	93.1	93.7	93.7	93.7	93.7	93.7	93.7	93.7	93.7	93.7	93.7	93.7
b	**Average Heat Rate (Btu/kWH)**	12,323	13,177	13,194	13,197	13,231	13,245	13,212	13,227	13,216	13,225	13,221	13,219	13,212	13,209	13,191	13,219
c	**Cost of Fuel ($/MBTU)**	1.18	[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

WATERSIDE 7

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	2.0	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	96.8	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
b	Average Heat Rate (Btu/kWH)	11,959	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000
c	Cost of Fuel ($/MBTU)	2.97	[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

WATERSIDE 8

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)	0.1	0.5	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	30.6	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
b	Average Heat Rate (Btu/kWH)	11,959	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000
c	Cost of Fuel ($/MBTU)	2.97	[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

ZORN 1

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	1.5	0.6	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	84.5	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
b	**Average Heat Rate (Btu/kWH)**	20,944	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	**Cost of Fuel ($/MBTU)**	2.66	[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. BROWN 5

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**				3.8	0.6	2.0	2.0	2.0	2.0	2.0	0.4	0.4	1.9	1.9	1.9	0.4
	Availability Factor (%)				86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2
b	**Average Heat Rate (Btu/kWH)**				12,268	10,929	12,257	12,242	12,268	12,292	12,304	10,947	10,936	12,323	12,337	12,313	10,919
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 1998 numbers are actuals.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 1

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)				4.0	2.4	2.3	2.3	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
	Availability Factor (%)				86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2
b	Average Heat Rate (Btu/kWH)				12,159	11,997	12,078	12,081	12,110	12,140	12,155	12,136	12,175	12,180	12,198	12,178	12,194
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 2

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**				4.3	2.9	2.7	5.5	4.0	3.9	3.9	2.4	2.3	2.3	2.3	3.8	2.2
	Availability Factor (%)				86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2
b	**Average Heat Rate (Btu/kWH)**				12,039	11,785	11,877	12,335	12,221	12,260	12,271	11,968	12,025	12,027	12,049	12,291	12,055
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 3

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)					5.7	6.8	7.2	5.7	5.7	5.6	5.7	4.0	4.1	5.5	4.0	4.0
	Availability Factor (%)					86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2
b	Average Heat Rate (Btu/kWH)					12,253	12,216	12,329	12,237	12,281	12,299	12,266	12,171	12,170	12,328	12,182	12,207
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 4

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)							7.2	7.5	7.4	7.3	7.4	7.2	7.3	7.2	5.8	7.1
	Availability Factor (%)							86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2
b	Average Heat Rate (Btu/kWH)							12,285	12,229	12,271	12,294	12,258	12,315	12,303	12,336	12,224	12,347
c	Cost of Fuel ($/MBTU)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 5

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**								7.5	7.8	7.6	7.8	7.5	7.5	7.4	7.4	7.3
	Availability Factor (%)								86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2
b	**Average Heat Rate (Btu/kWH)**								12,189	12,166	12,198	12,153	12,230	12,221	12,263	12,229	12,276
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 6

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)									7.7	8.1	11.1	7.9	7.8	7.6	7.8	7.6
	Availability Factor (%)									86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2
b	Average Heat Rate (Btu/kWH)									12,137	12,080	12,197	12,124	12,123	12,177	12,134	12,193
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 7

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**										7.9	12.4	9.7	9.9	9.6	8.2	8.0
	Availability Factor (%)										86.2	86.2	86.2	86.2	86.2	86.2	86.2
b	**Average Heat Rate (Btu/kWH)**										12,062	12,112	12,083	12,119	12,179	12,026	12,095
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 8

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)											8.4	12.0	11.8	10.1	11.8	8.5
	Availability Factor (%)											86.2	86.2	86.2	86.2	86.2	86.2
b	Average Heat Rate (Btu/kWH)											11,942	12,048	12,067	12,076	12,104	11,982
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 9

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**												10.2	13.3	11.9	14.0	11.0
	Availability Factor (%)												86.2	86.2	86.2	86.2	86.2
b	**Average Heat Rate (Btu/kWH)**												11,980	11,972	12,027	12,075	11,992
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

GREENFIELD CT 10

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)													10.5	15.3	16.5	15.1
	Availability Factor (%)													86.2	86.2	86.2	86.2
b	Average Heat Rate (Btu/kWH)													11,858	12,026	12,037	12,050
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

COMBINE CYCLE 1 (PHASE 1)

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)														11.2	18.8	8.7
	Availability Factor (%)														91.7	91.7	91.7
b	Average Heat Rate (Btu/kWH)														11,845	11,904	12,165
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

COMBINE CYCLE 1 (PHASE 2)

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)															14.1	10.9
	Availability Factor (%)															91.7	91.7
b	Average Heat Rate (Btu/kWH)															11,881	12,124
c	Cost of Fuel ($/MBTU)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

COMBINE CYCLE 1 (PHASE 3)

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	Capacity Factor (%)																19.2
	Availability Factor (%)																89.9
b	Average Heat Rate (Btu/kWH)																7,735
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Dix Dam 1,2,3

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	32.7	28.0	27.9	28.0	28.0	28.0	27.9	28.0	28.0	28.0	27.9	28.0	28.0	28.0	27.9	28.0
b	**Average Heat Rate (Btu/kWH)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none
c	**Cost of Fuel ($/MBTU)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Lock 7

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	---	37.6	37.5	37.6	37.6	37.6	37.5	37.6	37.6	37.6	37.5	37.6	37.6	37.6	37.5	37.6
b	**Average Heat Rate (Btu/kWH)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none
c	**Cost of Fuel ($/MBTU)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none

Notes: 1998 numbers are actuals.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ohio Falls 1-8

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
a	**Capacity Factor (%)**	58.4	79.1	78.9	79.1	79.1	79.1	78.7	79.1	79.1	79.1	78.9	79.1	79.1	79.1	78.9	79.1
b	**Average Heat Rate (Btu/kWH)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none
c	**Cost of Fuel ($/MBTU)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none

Notes: 1998 numbers are actuals.

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Table 8.(3)(b)12(d),(f)

Kentucky Utilities Company / Louisville Gas & Electric Company

Capital Costs and Escalation Factors
(In 1999 Dollars)

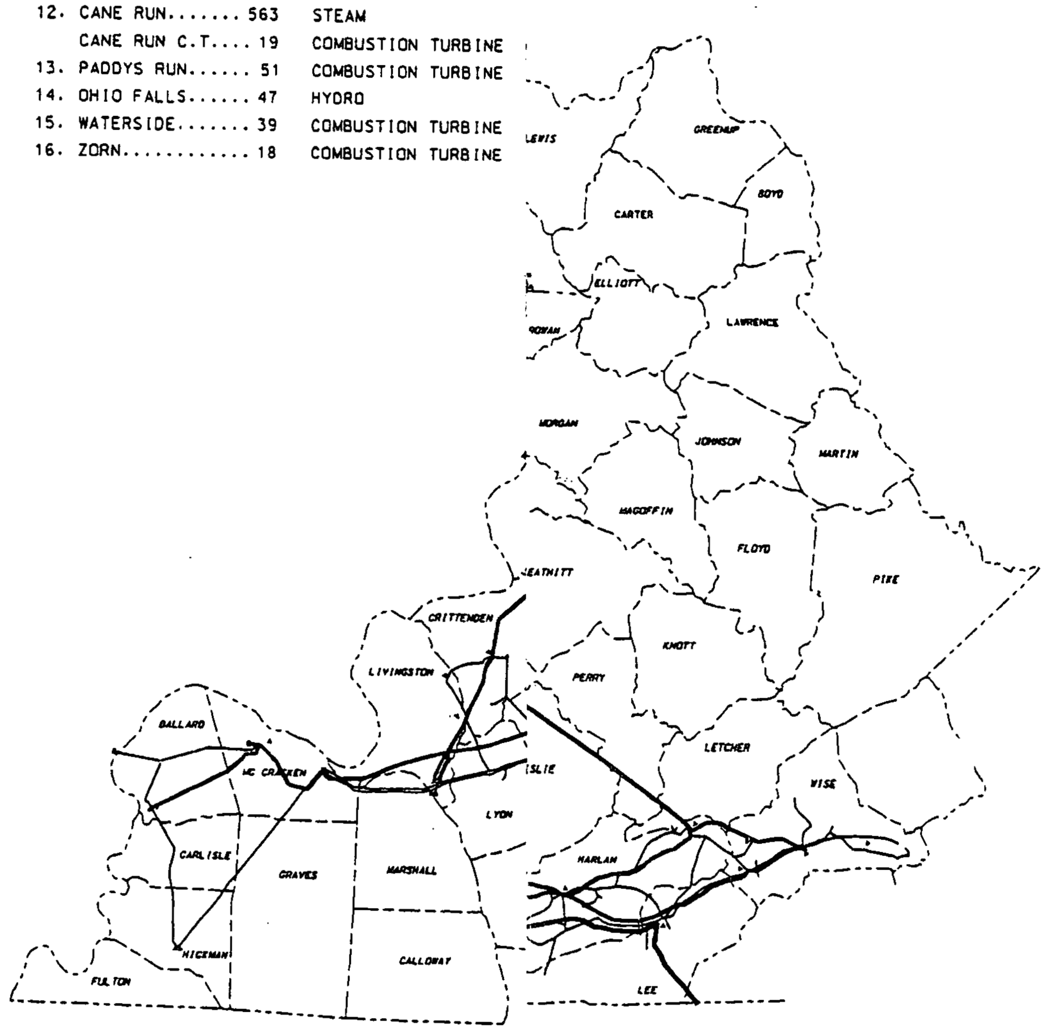
	E. W. Brown 5	Greenfield CT	CC 1 Phase 1	CC 1 Phase 2	CC 1 Phase 3
Capital Costs ($/kW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs($x1000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Escalation Factor (%)	2.0	2.0	2.0	2.0	2.0
Variable O&M Escalation Factor (%)	4.5	4.5	4.5	4.5	4.5
Fixed O&M Escalation Factor (%)	4.5	4.5	4.5	4.5	4.5

Fixed and Variable Escalation Factors also apply to existing units.
Capital Cost includes associated transmission substations.
$/kW based on summer rating.

GENERATION STATIONS

1.	E.W. BROWN..... 719	STEAM
2.	BROWN C.T...... 902	COMBUSTION TURBINE
3.	DIX DAM......... 24	HYDRO
4.	GHENT......... 1999	STEAM
5.	GREEN RIVER.... 238	STEAM
6.	HAEFLING........ 54	COMBUSTION TURBINE
7.	KU PARK......... 35	STEAM
8.	LOCK SEVEN....... 0	RUN OF RIVER
9.	TYRONE......... 135	STEAM
10.	TRIMBLE CO..... 371	STEAM
11.	MILL CREEK.... 1480	STEAM
12.	CANE RUN....... 563	STEAM
	CANE RUN C.T.... 19	COMBUSTION TURBINE
13.	PADDYS RUN...... 51	COMBUSTION TURBINE
14.	OHIO FALLS...... 47	HYDRO
15.	WATERSIDE....... 39	COMBUSTION TURBINE
16.	ZORN............ 18	COMBUSTION TURBINE

N



SCALE

10 0 10 20 30 40 MILES

10 0 10 20 30 40 50 KILOMETERS

10-11-99

Table 8.(3)(b)12(e)

Kentucky Utilities Company / Louisville Gas & Electric Company

Variable and Fixed Operating and Maintenance Costs ($000)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Existing units*	162,388	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
E.W. BROWN 5		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 2		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 3		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 4		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 5		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 6		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 7		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 8		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 9		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENFIELD CT 10		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
COMBINE CYCLE 1 (PHASE 1)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
COMBINE CYCLE 1 (PHASE 2)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
COMBINE CYCLE 1 (PHASE 3)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Data not available by individual units

Note 1: 1998 numbers are actuals.

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Table 8.3(b)12(g)

Kentucky Utilities Company / Louisville Gas & Electric Company

Total Electricity Production Costs (cents/kWh)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Existing units*	1.65	[redacted]														
E.W. BROWN 5		[redacted]														
GREENFIELD CT 1		[redacted]														
GREENFIELD CT 2		[redacted]														
GREENFIELD CT 3		[redacted]														
GREENFIELD CT 4		[redacted]														
GREENFIELD CT 5		[redacted]														
GREENFIELD CT 6		[redacted]														
GREENFIELD CT 7		[redacted]														
GREENFIELD CT 8		[redacted]														
GREENFIELD CT 9		[redacted]														
GREENFIELD CT 10		[redacted]														
COMBINE CYCLE 1 (PHASE 1)		[redacted]														
COMBINE CYCLE 1 (PHASE 2)		[redacted]														
COMBINE CYCLE 1 (PHASE 3)		[redacted]														

* Data not available by individual units

Note 1: 1998 numbers are actuals.

8.(3)(c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.

The requested information can be found in the Table 8.(3)(c) on the following page.

Table 8.(3)(c)

Kentucky Utilities Company / Louisville Gas & Electric Company

Description of Transactions for Purchases, Sales or Exchanges of Electricity

Purchases (GWH)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
OMU	1,796	1,574	1,784	1,794	1,564	1,828	1,816	1,827	1,825	1,828	1,658	1,820	1,722	1,812	1,811	1,811
EEI	1,605	1,485	1,508	1,504	1,504	1,504	1,509	1,502	1,503	1,504	1,509	1,503	1,504	1,504	1,449	1,398
OVEC	690	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219
Other	2,444	12	6	1	0	0	0	0	0	0	0	0	0	0	0	0

Sales (GWH)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
OMU	25	5	5	4	8	2	2	2	2	3	6	3	5	3	3	3
OTHER	8,167	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Note: 1998 numbers are actuals

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8.(3)(d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.

The requested information can be found in Table 8.(3)(d) on the following page.

Table 8.(3)(d)

Kentucky Utilities Company / Louisville Gas & Electric Company

Non-Utility Sources of Generation

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Generating Capacity	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Energy	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

8.(3)(e) For each existing and new conservation and load management or other demand-side programs included in the plan:

8.(3)(e)(1) Targeted classes and end-uses;

Existing Programs

KU Rate Schedule CWH (Combination Off-Peak Water Heating) – This program uses rate incentives to encourage customers in the residential and commercial sectors to shift water heating energy use from peak periods to off-peak periods. A special combination meter and time switch control the bottom water heater element.

KU Rate Schedule CSR (Curtailable Service Rider) – This program is aimed at decreasing demand in the industrial sector during system peak periods. In return for a rate incentive, participating customers agree to reduce demand to a predetermined level upon the Companies' request.

KU Rate Schedules LCI-TOD & LMP-TOD (Time-Of-Day Rates) – This program is targeted at the commercial and industrial sectors. A differential in on- and off-peak demand charge is used to encourage large customers to shift part of their demand from system peak periods to off-peak periods.

LG&E Rider for Interruptible Service – This program is targeted at the large commercial and industrial customers with a minimum of 1000 kilowatts of interruptible demand. Customers on this rider are given a demand credit in return for allowing the Companies to interrupt service during peak periods.

LG&E Rate Schedule LC-TOD and LP-TOD – This program is available to all large commercial and industrial customers in the LG&E service territory. Time-of-day rates are designed to more closely match the time-differentiated cost of providing service. This encourages the customers to control their energy cost during the peak demand periods.

Residential Energy Audits – This program targets customers within the LG&E service territory who own or occupy single-family homes, apartments or condominiums. It is designed to provide customers with an on-site home energy audit that will provide opportunities for improved energy efficiency.

Commercial Energy Audits - This program is offered to all commercial class customers in the LG&E service area, identified as all General Service (GS), Large Commercial (LC), and Large Commercial Time-of-Day (LC T-O-D) rate customers. The objective of this program is to identify energy efficiency opportunities for LG&E's commercial class customers and assist them in the implementation of these identified energy efficiency opportunities.

Future Programs

DLC Program – This is an aggregated program that targets the DLC of residential and commercial central air conditioning units and residential pool pumps of both KU and LG&E customers. It is designed to provide customers with an incentive to allow the Companies to interrupt service to their central air conditioners and/or pool pumps at those peak demand periods when the Companies need additional resources to meet customer demand.

Standby Generation – This is an aggregated program that targets commercial and industrial customers of both KU and LG&E who own backup generator units on their facilities. The industrial and commercial customers would receive a bill credit in return for allowing the

Companies to request the utilization of these backup generators during peak periods when the Companies need additional resources to meet customer demand.

Efficient Lighting – This is an aggregated program that targets residential customers with outdoor lighting, commercial and industrial lighting customers, and customers willing to install water heater blankets. Customers would be encouraged to install of higher efficient lighting equipment and to install water heater blankets.

8.(3)(e)(2) Expected duration of the program;

All existing rate programs are expected to continue into the future. The existing residential and commercial energy audit programs are continuously reviewed with the intention of constant improvement. Future DSM programs may be conducted as pilot programs until such time that they prove to be acceptable by the customers and provide the peak reduction benefits to the Companies.

8.(3)(e)(3) Projected energy changes by season, and summer and winter peak demand changes;

Load changes for the existing rate programs, excluding the LG&E Rider for Interruptible Service, have not been estimated, as they are currently captured in the Load Forecast. Table 8.(3)(e)(3) below summaries the annual energy impact and the summer and winter peak demand of the LG&E interruptible rate and the future programs.

8.(3)(e)(4) Projected cost, including any incentive payments and program administrative costs; and

The projected cost for the existing rate programs are not quantified. The Residential and Commercial Energy Audit programs will be re-evaluated and submitted as a part of the DSM filing mentioned in Section 5.(5) in Volume I.

The cost of the direct load control program that would control residential and commercial air conditioning units and residential pool pumps is approximately $1.5 million in NPV capital costs and $21.5 million in NPV expenses.

The cost of the customer-owned standby generation program that includes commercial and industrial customers is approximately $220 thousand in NPV capital costs and $700 thousand in NPV expenses. Also, incentives will be paid to the participants of this program in the form of demand and energy credits. The demand credit was assumed to be LG&E's existing demand credit for interruptible customers and the energy credit was assumed to be the avoided energy cost filed with the Commission.

The cost of the efficient lighting program is almost $4 million in NPV expenses. The efficient lighting program would include programs marketed to residential, commercial and industrial customers and their lighting needs along with a residential program promoting water heater wraps.

8.(3)(e)(5) Projected cost savings, including savings in utility's generation, transmission and distribution costs.

Projected cost savings for the existing rate programs are not quantified. The Residential and Commercial Energy Audit programs will be re-evaluated and submitted as a part of the DSM filing mentioned in Section 5.(5).

The difference between the PVRR with and without the direct load control program is $32.1 million. The difference between the PVRR with and without the standby generation program is $24.7 million. The difference between the PVRR with and without the high efficiency lighting program is $82.2 million. The high efficiency lighting program does not include any lost revenue recovery as a result of the conservation program. The PVRR figures listed above are in 1999 dollars.

Table 8.(3)(e)(3)

Kentucky Utilities Company / Louisville Gas & Electric Company

Conservation/DSM Energy and Demand Impacts

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Energy Reduction (GWH)																
Interruptible Rate	N/A	30	20	20	20	20	20	20	20	20	20	20	20	20	20	20
DLC Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Efficient Lighting	-	-	-	-	150	299	300	299	299	299	300	299	299	299	300	299
Standby Generation	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2
Summer Peak Demand Reduction (MW)																
Interruptible Rate	N/A	121	80	80	80	80	80	80	80	80	80	80	80	80	80	80
DLC Program	-	-	-	22	44	66	89	111	111	111	111	111	111	111	111	111
Efficient Lighting	-	-	-	-	23	46	46	46	46	46	46	46	46	46	46	46
Standby Generation	-	-	-	-	21	41	62	62	62	62	62	62	62	62	62	62
Winter Peak Demand Reduction (MW)																
Interruptible Rate	N/A	121	80	80	80	80	80	80	80	80	80	80	80	80	80	80
DLC Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Efficient Lighting	-	-	-	-	16	33	33	33	33	33	33	33	33	33	33	33
Standby Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

8.(4) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast:

The Companies' resource planning process considers the economics and practicality of available options to meet customer needs at the lowest practical cost. A study was completed to determine an optimal target reserve margin criterion to be used by the Companies. The results of this study suggested an optimal reserve margin in the range of 11% to 14%. In the development of the optimal integrated resource plan, the Companies used a reserve margin target of 12% to represent a base case scenario from this study. Details of this study entitled *Analysis of Reserve Margin Planning Criteria* (October 1999) can be found in Volume III, Technical Appendix. This section provides information associated with the recommended integrated resource plan resulting from the Companies' resource planning process outlined in Section 8.(5). The plan resulting from the Companies' optimal integrated resource plan analysis is shown below in Table 8.(4) and is detailed in a report titled, *Optimal Integrated Resource Plan Analysis* (October 1999) in Volume III, Technical Appendix. The in-service years for the units shown assume the Companies' Base Load Forecast.

The Companies continually pursue measures to maintain a reliable source of power. For 1999 summer contracts were in place to purchase 474 megawatts of peaking power in July and 200 MW in August, in addition to the early August 1999 commissioning of the E. W. Brown Units 6 and 7. Additional capacity to reliably meet customer demands for the summer of 2000 will be required. While the Companies are pursuing additional capacity for the summer of 2000, including thermal energy storage at the E. W. Brown Units 8-11 it is likely an additional 300 MW will need to be purchased.

Table 8.(4)
Recommended Plan

Year	Resource
1999	
2000	300 MW of Purchase Power
2001	160 MW Brown CT Unit 5 160 MW Greenfield CT Unit 1 160 MW Greenfield CT Unit 2 22.1 MW DLC program
2002	160 MW Greenfield CT Unit 3 22.1 MW DLC program 20.6 MW Standby Generation program 23.2 MW Efficient Lighting program
2003	22.1 MW DLC program 20.6 MW Standby Generation program 23.2 MW Efficient Lighting program
2004	160 MW Greenfield CT Unit 4 22.1 MW DLC program 20.6 MW Standby Generation program
2005	160 MW Greenfield CT Unit 5 22.1 MW DLC program
2006	160 MW Greenfield CT Unit 6
2007	160 MW Greenfield CT Unit 7
2008	160 MW Greenfield CT Unit 8
2009	160 MW Greenfield CT Unit 9
2010	160 MW Greenfield CT Unit 10
2011	160 MW Combined Cycle CT Phase 1
2012	160 MW Combined Cycle CT Phase 2
2013	150 MW Combined Cycle CT Phase 3

8.(4)(a) On total resource capacity available at the winter and summer peak:

1. **Forecast peak load;**
2. **Capacity from existing resources before consideration of retirements;**
3. **Capacity from planned utility-owned generating plant capacity additions;**
4. **Capacity available from firm purchases from other utilities;**
5. **Capacity available from firm purchases from nonutility sources of generation;**
6. **Reductions or increases in peak demand from new conservation and load management or other demand-side programs;**
7. **Committed capacity sales to wholesale customers coincident with peak;**
8. **Planned retirements;**
9. **Reserve requirements;**
10. **Capacity excess or deficit;**
11. **Capacity or reserve margin.**

The requested information can be found in Table 8.(4)(a)-1 and Table 8.(4)(a)-2 on the following pages.

Table 8.(4)(a)-1

Kentucky Utilities Company / Louisville Gas & Electric Company

Resource Assesment and Acquisition Plan

Resource Capacity Available (MW)

At Summer Peak

#		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1	**Forecasted Peak Load**	5986	6350	6531	6665	6805	6952	7127	7270	7416	7547	7672	7819	7986	8138	8275	8397
6	**Existing Peak Reductions**	123	121	80	80	80	80	80	80	80	80	80	80	80	80	80	80
	Planned Peak Reduction	0	0	0	22	88	154	197	219	219	219	219	219	219	219	219	219
	Total Demand	5863	6229	6451	6563	6637	6718	6850	6971	7117	7248	7373	7520	7687	7839	7976	8098
	Capacity From:																
2	**Existing Resources**	6132	6132	6539	6539	7018	7165	7165	7324	7484	7643	7803	7962	8097	8257	8416	8576
3	**Planned Resources**	0	0	0	480	160	0	160	160	160	160	160	160	160	160	160	150
4	**Firm Purchases:**																
	EEI (MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	OMU (MW)	207	199	192	186	185	183	182	180	178	177	175	171	168	164	160	156
	Short Term (MW)	270	474	300													
5	**Firm Purchases Non-Utility**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	**Committed Capacity Sales**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	**Planned Retirements**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Supply	6809	7005	7231	7405	7563	7548	7707	7864	8022	8180	8338	8493	8625	8781	8936	9082
9	**Reserve Requirements**	704	747	774	788	796	806	822	837	854	870	885	902	922	941	957	972
10	**Excess (Deficit)**	242	28	6	54	130	24	34	57	50	62	80	70	16	1	3	12
11	**Reserve Margin (%)**	16.1%	12.5%	12.1%	12.8%	14.0%	12.4%	12.5%	12.8%	12.7%	12.9%	13.1%	12.9%	12.2%	12.0%	12.0%	12.1%

Note: 1998 forecasted peak is actual, Capacity and peak reduction are planned values.
Note: 1999 Capacity Resources were actual arrangements based upon previous peak forecast

Table 8.(4)(a)-2

Kentucky Utilities Company / Louisville Gas & Electric Company

Resource Assesment and Acquisition Plan

Resource Capacity Available (MW)

At Winter Peak

		98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
1	**Forecasted Peak Load**	5282	5415	5527	5654	5783	5935	6033	6158	6260	6382	6514	6650	6744	6871	6966	7081
6	**Existing Peak Reductions**	123	121	80	80	80	80	80	80	80	80	80	80	80	80	80	80
	Planned Peak Reduction	0	0	0	16	33	33	33	33	33	33	33	33	33	33	33	33
	Total Demand	5159	5294	5447	5558	5670	5823	5920	6046	6147	6269	6402	6538	6632	6758	6853	6968
	Capacity From:																
2	**Existing Resources**	6319	6681	6680	6680	7235	7407	7407	7591	7776	7960	8145	8330	8514	8337	8521	8706
3	**Planned Resources**	0	0	0	555	185	0	185	185	185	185	185	185	185	185	185	150
4	**Firm Purchases:**																
	EEI (MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	OMU (MW)	207	199	192	186	185	183	182	180	178	177	175	171	168	164	160	156
5	**Firm Purchases Non-Utility**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	**Committed Capacity Sales**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	**Planned Retirements**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Supply	6726	7080	7072	7621	7805	7790	7974	8156	8339	8522	8705	8886	9067	8886	9066	9212
9	**Reserve Requirements**	619	635	654	667	680	699	710	725	738	752	768	785	796	811	822	836
10	**Excess (Deficit)**	948	1151	972	1396	1454	1269	1343	1385	1454	1501	1535	1563	1640	1317	1391	1408
11	**Reserve Margin (%)**	30.4%	33.7%	29.8%	37.1%	37.6%	33.8%	34.7%	34.9%	35.7%	36.0%	36.0%	35.9%	36.7%	31.5%	32.3%	32.2%

Note: 1998/1999 forecasted peak is actual January 1999
Capacity and peak reduction are planned values

8.(4)(b) On planned annual generation:

1. **Total forecast firm energy requirements;**
2. **Energy from existing and planned utility generating resources disaggregated by primary fuel type;**
3. **Energy from firm purchases from other utilities;**
4. **Energy from firm purchases from nonutility sources of generation; and**
5. **Reductions or increases in energy from new conservation and load management or other demand-side programs;**

The requested information can be found in Table 8.(4)(b) on the following page.

Table 8.(4)(b)

Kentucky Utilities Company / Louisville Gas & Electric Company

Forecast Annual Energy (GWH)

1	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Energy Requirements	30,278	31,053	31,975	32,810	33,574	34,255	35,060	35,620	36,279	36,971	37,732	38,372	39,096	39,771	40,533	41,162

2 Energy by Fuel Type	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Coal	31,361	27,176	27,768	28,469	29,273	29,477	30,223	30,655	31,189	31,650	32,248	32,600	33,116	33,519	33,816	34,234
Gas	255	167	284	419	466	529	600	729	858	1,089	1,423	1,558	1,867	2,053	2,577	2,844
Oil	7	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	311	394	390	386	382	378	373	370	366	362	358	354	350	346	341	337

3 Firm Purchases From Other Utilities	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
OMU	1,796	1,574	1,784	1,794	1,564	1,828	1,816	1,827	1,825	1,828	1,658	1,820	1,722	1,812	1,811	1,811
EEI	1,605	1,485	1,508	1,504	1,504	1,504	1,509	1,502	1,503	1,504	1,509	1,503	1,504	1,504	1,449	1,398
OVEC	690	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219
Other	2,444	12	6	1	0	0	0	0	0	0	0	0	0	0	0	0

4	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Purchases From Non-Utility	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

5	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Reductions / Increases in Energy	0	(30)	(20)	(20)	(172)	(322)	(322)	(322)	(322)	(322)	(322)	(322)	(322)	(322)	(322)	(322)

Note: 1998 numbers are actuals

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8.(4)(c) For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.

The requested information can be found in Table 8.(4)(c) on the following page.

Table 8.(4)(c)

Kentucky Utilities Company / Louisville Gas & Electric Company

Total Energy Input and Total Generation by Primary Fuel Type

Coal	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Energy (GWH)	31,361	27,176	27,768	28,469	29,273	29,477	30,223	30,655	31,189	31,650	32,248	32,600	33,116	33,519	33,816	34,234
Total (000 Tons)	13,736	11,778	12,014	12,319	12,639	12,834	13,156	13,325	13,544	13,724	13,959	14,118	14,326	14,493	14,615	14,774
(000 MBTUs) Consumed	324,177	283,967	289,821	296,967	304,717	308,254	315,812	319,934	325,157	329,651	335,242	339,195	344,285	348,322	351,157	355,188

Gas	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Energy (GWH)	255	167	284	419	466	529	600	729	858	1,089	1,423	1,558	1,867	2,053	2,577	2,844
Total (000 MCF)	3,318	2,148	3,510	5,126	5,709	6,514	7,376	8,922	10,479	13,317	17,338	18,971	22,689	24,939	31,174	31,038
(000 MBTUs) Consumed	3,324	2,149	3,510	5,126	5,709	6,514	7,376	8,922	10,479	13,317	17,338	18,971	22,689	24,939	31,174	31,038

Oil	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Energy (GWH)	7	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Total (000 Gallons)	980	272	178	45	12	11	15	13	12	13	12	12	13	14	14	13
(000 MBTUs) Consumed	137	38	25	6	2	2	2	2	2	2	2	2	2	2	2	2

Hydro	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Energy (GWH)	311	394	390	386	382	378	373	370	366	362	358	354	350	346	341	337

Note: 1998 numbers are actuals

8.(5) The resource assessment and acquisition plan shall include a description and discussion of:

8.(5)(a) General methodological approach, models, data sets, and information used by the company;

The Companies resource planning process involves; 1) establishment of a target reserve margin criterion, 2) assessment of adequacy of existing generating units and purchase power agreements, 3) assessment of potential purchase power suppliers, 4) assessment of demand-side options, 5) assessment of supply-side options and 6) evaluation of the lowest cost plan that can be developed for the available options.

To aid in the integrated resource planning process, the Companies use a state-of-the-art software package, PROSCREEN II, to evaluate resource options. PROSCREEN II contains several modules, which can be executed in various ways to evaluate resource options. The Load Forecast and Adjustment (LFA), Generation and Fuel (GAF), Proview (PRV), and Capital Expenditures and Recovery (CER) modules of PROSCREEN II are used to evaluate resource options. PRV uses the LFA and GAF modules in a production analysis along with construction expenditure information from the CER to suggest an optimal and several suboptimal plans based on the minimum PVRR criterion. Proview is used in various sensitivity scenarios to determine optimal resource plans. A more detailed description of how PROSCREEN II is used and its input data is contained in a report titled *Optimal Integrated Resource Plan Analysis* (October 1999) in Volume III, Technical Appendix.

Demand Side Management Resource Screening and Assessment

The Companies formed an inter-departmental team to select the DSM options to be included in this study. The DSM team identified a broad range of DSM alternatives and developed a long list of alternatives. Each alternative on this long list was investigated and evaluated using a two-step screening process. The first phase was qualitative in nature, and each alternative was evaluated based on four criteria (see Table 8.(5)(c)-1 for a listing of the criteria). The second phase of screening was quantitative in nature and was performed using EPRI's DSManager software. DSManager is a PC-based software package developed by EPS Solutions under contract with EPRI. It is a screening tool that determines the cost effectiveness of DSM programs by modeling their costs and benefits over a period of time. The program simplifies the "real world" by using 48 typical days to represent a year. There are four daily load shapes per month, each representing a specific type of day. The day types are high, medium, and low weekday, and weekend. Additional detail on this process is contained in the report titled *Screening of Demand-Side Management (DSM) Options* (September 1999) contained in Volume III, Technical Appendix.

Supply Side Resource Screening Assessment

Various supply-side options, including both mature and emerging technologies, were evaluated as part of the integrated resource planning process. The Electric Power Research Institute (EPRI) software package, TAG Supply for Windows Version 3.08, was utilized to perform the detailed screening analysis. TAG provides data on numerous mature and emerging technologies. Additional detail on this process is contained in the report titled *Analysis of Supply-Side Technology Alternatives* (August 1999) contained in Volume III, Technical Appendix.

8.(5)(b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;

The process of determining an optimal integrated resource plan involves the modeling of the Companies' existing generation system and various possible options, either demand-side or supply-side, as resources to meet growing customer needs. Key assumptions and uncertainties are: 1) forecasted fuel prices, 2) forecasted customer load requirements, 3) capital and operating costs related to new generation construction, 4) Clean Air Act Compliance, 5) availability of existing and new generating units and purchases, 6) weather uncertainties and 7) potential CO_2 regulation. A discussion of each key issues follows.

Fuel Forecast

The Companies' fuel forecasts are updated annually as part of the Companies' planning cycle. WEFA Inc. (WEFA) provides the Companies with price forecasts for fuel oil, natural gas and various coal qualities to be used at the Companies' generating plants. Included with these forecasts are macro-economic energy analyses. These WEFA forecasts are used to price fuel purchases for each year to satisfy estimated fuel usage requirements that are not already under existing long-term or spot commitments. Long-term contract prices are escalated to the end of their contract terms (for both fuel and transportation) as specified in the terms and conditions of the contract or by the appropriate escalators provided by WEFA or both.

WEFA data is modified as appropriately to reflect recent information (solicitations, consummated purchases, etc.). Forecasted fuel prices and transportation charges are combined and the resulting delivered price to the various generating plants is appended to either existing commitments or forecasted fuel purchases. All purchases are weight-averages by expected volume and computes average annual estimated delivered fuel prices by type of fuel.

Currently, three types of fuel are simulated in the integrated resource plan analysis: coal, oil and natural gas. A major change in future oil, gas or coal prices can have a significant impact on the selection of new units and the operation of existing units. Therefore, a fuel sensitivity analysis utilizing three fuel forecasts (Base, High, Low) and associated probabilities of occurrence (70% Base, 15% High and Low) is incorporated into the process of determining an optimal integrated resource plan. Fuel sensitivities were also factored into the screening of supply-side technologies as discussed in the report titled *Analysis of Supply-Side Technology Alternatives* (August 1999) contained in Volume III, Technical Appendix.

Forecasted Customer Load Requirements

The load forecast (demand and energy forecast) is another significant factor influencing the Companies' optimal resource plan analysis. Each resource option is designed or selected for optimal performance at specific levels of utilization. For instance, CTs are relatively inexpensive to construct (compared to coal-fired units), but are more costly to operate and maintain. Conversely, coal-fired units are expensive to construct but are relatively inexpensive to operate and maintain. The economics of adding an option to any generation system is based on the expected costs of operating and maintaining the unit over the full range of loads it is expected to serve. Significant economic penalties (costs higher than expected) may be incurred if the unit is operated above or below the level it was planned to serve. For example, if a CT was added to a system in which load was greater than forecasted, the utilization of the CT may exceed the economical range for which it was planned. In other words, it may have been more economical to install intermediate load serving capacity such as a combustion turbine combined cycle (CT-CC) unit. Thus, load growth scenarios that are different from that which is expected may have a significant impact on the selection of an optimal technology, type and size. Therefore, in order to evaluate the effect of various load forecasts, a load sensitivity analysis has been incorporated in the Companies' process of determining an optimal integrated resource plan.

In summary, three load forecasts and their associated probabilities of occurrence were developed. The three forecasts depict an expected system load growth case, a case where system load growth exceeds expected growth and a case in which system load growth is less than expected. The resulting forecasts are referred to respectively as the *base, high,* and *low.* The details of and the basis for the various load forecasts are described in Volume II, Technical Appendix.

New Unit Estimated Costs

A significant change in the capital cost of a new unit or its operating expenses can result in a different selection of units in the optimal integrated resource plan strategy. EPRI provides utilities sound data through the TAG Supply computer software package, which includes an on-line documentation of the Technical Assessment Guide previously published for EPRI members. TAG Supply is a PC software package developed to help tailor TAG data to utility specific values. The TAG document contains various supply-side technology types, descriptions and technical explanations, capital costs and capital cost ranges, facility MW sizes, fuels and other technology-specific parametric data from engineering cost studies by EPRI, researchers and manufacturers. As discussed in the report titled *Analysis of Supply-Side Technology Alternatives* (August 1999) contained in Volume III, Technical Appendix, a base, low and high capital cost sensitivity was incorporated into the screening analysis.

Market forces can and do have a major impact on the pricing and availability of new units. The wholesale power prices from the recent summers, 1998 and 1999, have impacted the demand for combustion turbine units by all entities involved in delivering power. The pricing and availability of combustion turbines, or any other resources that are highly desirable by entities involved in delivering power, may be drastically different than those prices utilized in the supply-side screening analysis and in the integrated analysis when it comes time to actually purchase and install the units. The Companies will continue to closely monitor activity in the market through its RFP process and industry contacts so that the least-costly resource will be utilized to reliably meet customer demand.

Clean Air Act Compliance Plan

Compliance with Phase I of the Clean Air Act Amendment of 1990 resulted in the installation of a flue gas desulfurization (FGD) system (scrubber) at KU's Ghent Unit 1 in 1995. The LG&E units were fully scrubbed and therefore were not Phase I affected units. The Companies' current Clean Air Act Compliance Plan consists of overscrubbing all existing scrubbed units beginning in 2000 and retrofitting a scrubber (FGD) on Ghent Unit 2 and fuel switching to high sulfur coal in 2003. Throughout 2000 the Companies will continue to evaluate the optimal scrubbing level of the existing scrubbed units in order to maximize the benefits to the ratepayers and shareholders. Additional detail on the Companies' compliance plan is included in a report titled *Clean Air Act Amendments of 1990 Compliance Plan, 1999 Environmental Compliance Analysis* (October 1999) Volume III, Technical Appendix.

Existing and New Unit/Purchase Availability

The Companies' existing capacity resources are comprised of both owned generating units and purchase power agreements. A significant amount of historical data exists on these units and was used to model the future availability of the units. The availability of new generating units and purchases was determined based on the Companies' experience and projected availability from EPRI's TAG Supply.

The Companies are two of fifteen sponsoring companies of the Ohio Valley Electric Corporation (OVEC) and presently own 9.5% of the equity in the generating capacity. OVEC is under contract to supply energy to the Department of Energy's (DOE) gaseous diffusion plant near Piketon, Ohio. DOE currently requires the full output of the OVEC generating facilities, after making allowances for reserve requirements and transmission losses. With the DOE paying the full demand charges, the sponsors can claim no capacity from the generating facilities, however the Companies and other sponsors can claim surplus energy as available.

The availability and prices of purchase power from the wholesale market as a future resource can be drastically affected by market forces. Recent price spikes in the summers of 1998 and 1999 have caused a fundamental change in the pricing and availability of power to reliably meet peak demands of the Companies' customers. The Companies accounted for this uncertainty in the optimization studies by excluding peaking type power purchases from the integrated resource plan analysis. Peaking type purchase power opportunities in optimization studies would serve only to evaluate the delay of CT construction for short periods of time, which is already being considered in greater detail by the Companies' RFP process.

Uncertainty in the Planning Process Caused by Weather

Recent summer experiences indicate that during peak load periods, the Companies' reserves are reaching maximum utilization. The Companies' expected reserve margin for the 1999 summer season was estimated prior to the summer to be 14%. Yet on the peak days after contingencies, the reserve margin was 5.1% in 1999. The differences between the expected reserve margin and the actual observed reserved margin were due to the variances in load, available generation, reduced capacity due to equipment problems, and available purchases.

During the hour ending 2:00 p.m. eastern standard time on July 30, 1999 the Companies' all-time peak load (including buy-thru customers' load) was established at 6357 megawatts. The Companies' July 1999 capacity rating was 6131 megawatts, 179 megawatts less than the winter capacity rating. In general, the Companies have less installed capacity available in the summer season than in the winter season due to the effect of the summer weather conditions on the operating characteristics of each unit. At the time of the 1999 peak, the Companies' resources were composed of KU/LGE-owned units and 691 megawatts of native-load purchases. On the 1999 summer peak day, capacity available for native load from company owned units was 416 megawatts less than the summer rating due to unit derates and the maintaining of spinning reserve. Scheduled purchases from EEInc and OMU were in the aggregate 63 megawatts less than expected. LGE actual interruptible was 75 megawatts less than anticipated. These factors coupled with a higher than planned peak load (+106 megawatts) resulted in a reserve margin of 5.1%. The 5.1% actual capacity reserve experienced on the summer peak day 1999 exceeds the East Central Reliability Area Coordination Agreement (ECAR) recommended minimum daily operating reserve requirement of approximately 4%. As a member of ECAR, the Companies strive to maintain a level of daily operating reserve of approximately 4% of projected daily peak load to ensure a high degree of service continuity for its system and ECAR. Thus, during the all-time peak load period of 1999, the Companies met customer native load demand while maintaining the recommended daily ECAR reserves requirement.

Table 8.(5)(b) shows pertinent system data for the 1999 summer peak day. Figure 8.(5)(b) complements Table 8.(5)(b) and illustrates the frequency and magnitudes of the Companies' daily summer peak loads during July and August of 1999. As shown in Table 8.5(b), the Companies' actual reserve margin can be less than expected. Actual reserve margin levels varies as a result of abnormal weather, unit equipment problems, and the unavailability of contract purchases.

Even though the Companies' actual reserve margin dropped significantly below expected levels due to extreme weather and equipment conditions, there was no customer loss of service due to inadequate capacity resources.

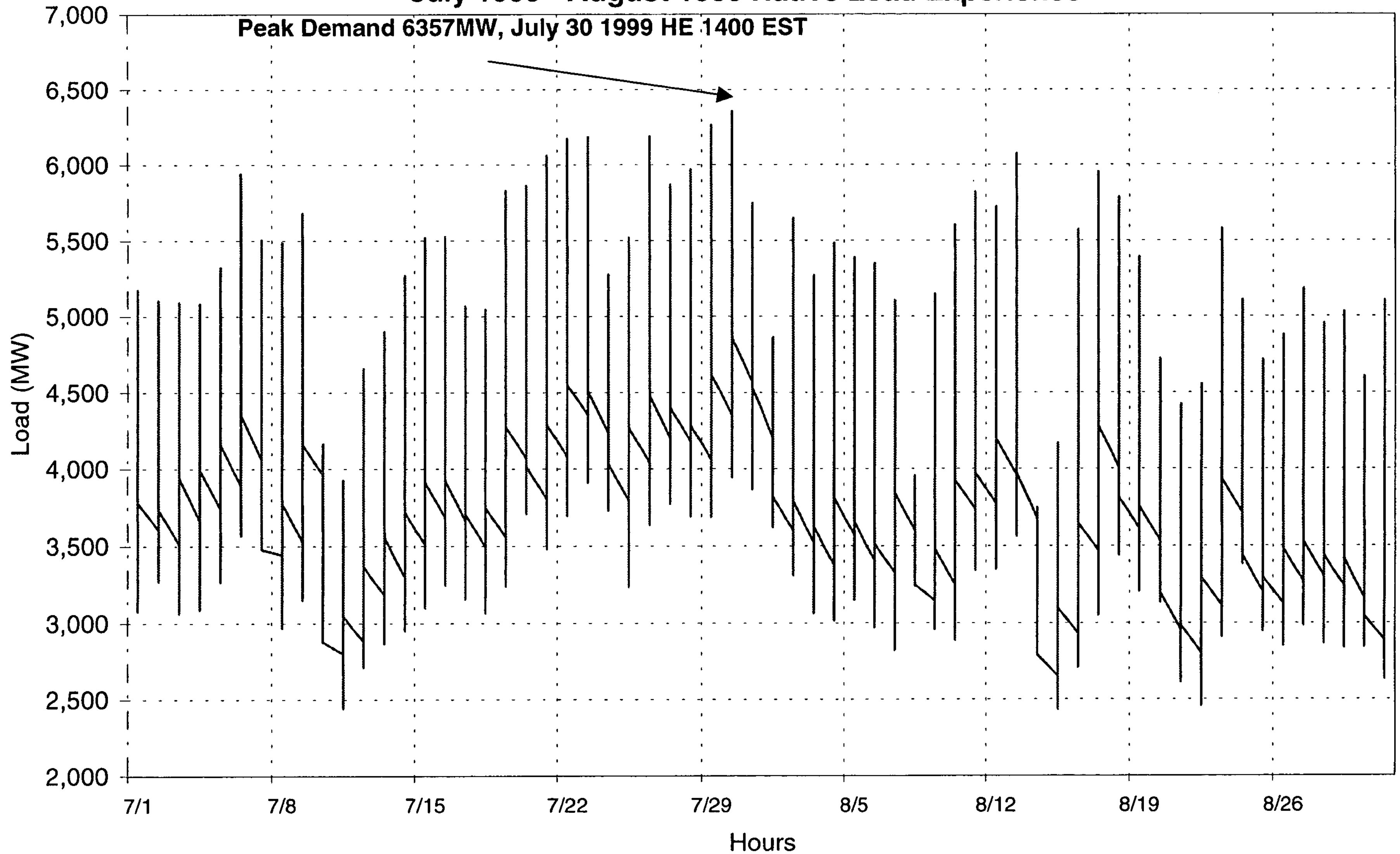
Table 8.(5)(b)
Recent Summer Load Experience

Data (MW)	July 30, 1999
Expected Peak Load less KU CSR	6251
Expected Interruptible Impact	123
Expected Native Peak Load	6128
Expected Resources	
KU/LGE Units	6131
+Contract Purchase	873
Total	7004
Expected Reserve Margin	14.3%
Actual Peak Load less KU CSR	6357
Actual LGE Interruptible Impact	48
Actual Native Peak Load	**6,309**
Actual Resources	
KU/LGE Unit	5666
+ Spinning	275
+Contract Purchases	336
+Off-Sys Purchase	355
-OMU Contract Sales	0
Sub Total	**6632**
Actual Reserve Margin	5.1%
ECAR Required Reserves	254
Total Actual Resources less	
ECAR Reserves	6378
Reserve Margin w/o	
ECAR Reserves	1.1%

Note:
Contract and Off System Purchases are for native load.

Figure 8.(5)(b)

Kentucky Utilities Company / Louisville Gas & Electric Company
July 1999 - August 1999 Native Load Experience



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Potential CO_2 Regulation

There exists the possibility that reductions in carbon dioxide emissions will be required, although no requirements are in place at this time. Such reductions could be required as part of an effort to reduce emissions of greenhouse gases (GHG) and potential global climate change. Some of the proposed measures include:

Clean Energy Act of 1999 - On July 14th, Sen. Jeffords (R-Vt.) introduced legislation to set national emissions caps (effective in 2005) on power plant emissions of CO_2 (1.9 B tons), NO_x (1.7 M tons), mercury (5.0 tons), and SO_2 (3.6 M tons). Each fossil fuel utility plant would be required to meet an individual cap based on its electrical generation. This discourages the use of coal as a fuel because facilities that don't burn coal can produce a unit of energy with less "pollution." In addition, the legislation would establish an "energy portfolio standard" requiring companies to use a minimum percentage of renewable energy sources (from 2.5% in 2000 to 20% in 2020).

Credit for Voluntary Reductions Act – Legislation was reintroduced this Congress by a bipartisan group of eleven Senators which would:

1) give credit to companies that voluntarily reduce their greenhouse gas emissions from 1999 through 2008 (these credits could then be used to offset any obligation for GHG reductions that might stem from future domestic control requirements) and

2) authorize the President to enter into emission-reduction agreements with U.S. businesses. A similar bill was introduced in the House on July 14th.

Report to Congress on CO_2 Emissions - As part of the Administration's proposal to promote retail competition, President Clinton has directed EPA and DOE to prepare a joint annual report of emissions from electricity generators. The annual report will detail CO_2 emissions from all electric generators providing power to the grid. The intent is to allow consumers to incorporate this information in choosing a retail supplier. The first Report to Congress on CO_2 emissions is due October 1999 for 1998 data.

Kyoto Protocol – The 1997 Kyoto Protocol on climate change, if ratified by the Senate, could require the U.S. to reduce emissions of six greenhouse gases by 7% below 1990 levels in the 2008-2012 time period. Last Congress, several committees held hearings on the Kyoto Protocol and its implications. A number of bills, resolutions and provisions in appropriations bills were introduced or considered, mostly to limit activities of the U.S. government that are or could be seen as related to carrying out the goals of the Kyoto Protocol. The Administration has indicated that until developing countries also make commitments to participate in greenhouse gas limitations, it will not submit the protocol to the Senate for advice and consent, thereby delaying indefinitely any possibility of ratification.

Currently there are no regulations that would restrict the emission of CO_2, however, there are multiple proposals that might be in place in the future. To capture this possibility in the Companies' IRP process, an environmental cost adder for the cost of CO_2 emissions was included in the supply-side screening analysis. Details of this process can be found in the report titled *Analysis of Supply-Side Technology Alternatives* (August 1999) contained in Volume III, Technical Appendix.

8.(5)(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan;

Demand-side Management Screening

Prior to the optimization process, a screening analysis of Demand-Side Management (DSM) options was conducted. The purpose of the screening analysis was to evaluate cost effective DSM options to use in PROSCREEN II optimizations. The following is a summary of the DSM screening methodology and subsequent findings. A detailed report of the screening analysis titled *Screening of Demand-Side Management (DSM) Options* (September 1999) can be found in Volume III, Technical Appendix.

The Companies formed an inter-departmental team to select the DSM options. This DSM team brainstormed to identify a broad range of DSM alternatives and developed a long list of DSM alternatives. Each alternative on this long list was investigated and evaluated using a two step screening process. The first step was qualitative in nature, where each alternative was evaluated based on four criteria. The alternatives that passed the first step underwent a second step of screening that was quantitative in nature. The quantitative screening process was broken down into two separate phases, which are discussed below. The DSM programs that passed the quantitative screening process were then aggregated into three DSM programs to compete with supply-side alternatives in the integrated analysis.

The qualitative analysis began with the selection of the criteria on which to base the comparison of DSM options. Based upon the Companies' objectives to provide low cost, reliable energy to our customers and the comments from the PSC Staff Report on each of the Companies' most recently filed IRP, four criteria were selected. The next task was to assign weights or values to each of the criteria. The highest weights were assigned to the criteria judged to be the most important to develop a successful DSM program. The two most important criteria were customer acceptance and the effectiveness of each DSM alternative in meeting load shape objectives. Each potential DSM option was evaluated, based on a scale of 0 to 4, using the four criteria. The four criteria, their weights, and an explanation of each are shown in Table 8.(5)(c)-1.

Table 8.(5)(c)-1
Qualitative Screening Criteria

Criteria	Description	Weighting
Customer Cost	Will a participant's benefits exceed their costs by utilizing this measure?	20%
Customer Acceptance	Are there an acceptable number of customers willing to participate to create a successful program?	30%
Maturity of Technology/ Data Confidence	Is the technology commercially available? Is the necessary data available to evaluate this measure?	20%
Meets Load Shape Objectives	Does the measure have the ability to reduce the seasonal coincident peak demand or increase the annual system load factor?	30%

The programs that passed the qualitative screening process were modeled in more detail using EPRI's DSManager software as part of the quantitative screening process. DSManager calculates the net present value of the quantifiable costs and benefits assignable to both the Companies and the customers participating in a DSM program. For each DSM initiative, DSManager requires the administrative costs, participant's costs, life span of the technology, expected level of participation, expected level of free riders, and rate schedules. DSManager calculates changes to the participant's bill, changes in the Companies' revenue, changes in production costs, and changes in the peak demand. The present value for each DSM alternative is calculated, by DSManager, and reported as the costs and benefits using the five "California Tests." These five tests include the participant, utility cost, ratepayer impact measure (RIM), total resource cost (TRC), and societal cost tests. The Companies used only the participant and TRC tests to screen DSM options. The participant test includes changes in all costs and benefits to the customer installing the DSM option. The TRC test combines the RIM and participant tests and indicates overall benefits of the DSM option to the average customer, whereas the RIM test considers all impacts to the non-participants.

The quantitative screening was set up in two phases. In Phase I, the cost to administer the program was not considered and it was assumed that the program had only one participant per company. This phase was created to remove non-cost effective programs. If the benefits of a program do not exceed the cost of the program without the administration cost, then it will not pass with a higher penetration of customers and the added burden of the administrative costs. The only cost included in this phase was the incremental cost of the DSM alternative. Each program that passed Phase I of the quantitative screening process was put through a program design phase (Phase II). The costs to administer the programs and the expected levels of penetration were added to the programs that passed Phase I. Each program has to pass the Participants Test and the TRC to be evaluated further.

There were nine programs that passed the quantitative screening process. These nine programs were aggregated into three DSM programs before competing with the supply-side alternatives in the integrated analysis. Table 8.(5)(c)-2 contains a listing of the three DSM programs suggested for detailed analysis within PROSCREEN II. The direct load control (DLC) of residential air conditioning, the DLC of swimming pools, and the DLC of commercial air conditioning programs were aggregated into one DLC program. The two standby generation programs (commercial and industrial) were aggregated into another DSM program. The three lighting programs (residential, commercial and industrial) and the water heater wrap program were aggregated into the third DSM program. Aggregating the programs has two benefits in the integrated analysis: (1) it reduces computer simulation time because of fewer alternatives, and (2) it makes the DSM programs larger (in peak MW reduction).

Table 8.(5)(c)-2
DSM Programs Suggested for Analysis
Within PROSCREEN II

Aggregate Program	Individual Program
Direct Load Control (5 phases of 22 MW each)	Residential DLC of Central A/C Residential DLC of Pool Pumps Commercial DLC of Central A/C
Standby Generation (2 phases of 23 MW each)	Commercial Standby Generation Industrial Standby Generation
Efficient Lighting (4 phases of 20 MW each)	Residential Outdoor lighting Commercial Lighting Industrial Lighting Water Heater Wrap Up

Supply-side Screening

As a precursor to the optimization process, a technology screening analysis was conducted. The purpose of the screening analysis was to evaluate, compare and suggest the least-cost supply-side options to use in PROSCREEN II optimizations. The following is a summary of the technology screening methodology and subsequent findings. A detailed report of the screening analysis titled *Analysis of Supply-Side Technology Alternatives* (August 1999) can be found in Volume III, Technical Appendix.

The Electric Power Research Institute (EPRI) published their Technical Assessment Guide (TAG) in 1993. Since then, EPRI has developed a computer software package, TAG Supply, that contains the documentation and data in a computer based environment. The latest version of TAG Supply, TAG Supply for Windows Version 3.08, was utilized as the main source of data. EPRI's April 1999 database release was incorporated into the software package and utilized in the screening analysis. TAG provides data and methods for determining the relative cost and performance of current/advanced electric generation and storage technologies.

Adjustments were made to each technology within TAG Supply to insure the most accurate cost and performance estimates for each technology. The following data adjustments were made during the course of this analysis:

(1) regionalized each technology to the East Central region, which includes the Commonwealth of Kentucky.

(2) assigned the Companies' specific economic data (cost of capital, inflation rate, income tax rate and property tax rates), labor rates, and limestone cost representative of the Companies' cost to each technology.

(3) revised combustion turbine (CT) cost for TAG Supply technologies 15.1, 15.2, and 15.3 to reflect current bid prices for these types and sizes of CTs.

(4) adjusted TAG Supply technologies 16.1 and 16.2 to reflect a two (CT) on one (Heat Recovery Steam Generator) design for a combustion turbine combined-cycle (CT-CC) instead of the single shaft CT-CC setup utilized in TAG Supply.

No technology was excluded from the screening analysis based solely on its technical maturity, practicality, or feasibility. For example, even though climatical information for Kentucky suggests wind turbine technology would not be a practical supply-side option in Kentucky, wind turbine technology was not excluded from the analysis.

In order to pass a comprehensive list of supply side options to PROSCREEN II for evaluation, two cases along with three sensitivities were incorporated into the screening analysis. The first case, referred to as the base analysis, includes the impact that the emission of SO_2 can have on the selection of technologies. The second case, which also includes the cost of SO_2 emissions, evaluates the potential additional cost of carbon dioxide emissions. Each of these cases included the cost of mitigating NO_x emissions through technology included in the capital cost of the alternative evaluated in TAG Supply. The three sensitivity variables were capital cost, heat rate, and fuel cost. For each of the three sensitivity variables, high and low values were determined, in addition to the base values supplied by TAG Supply. The percent adjustment made to capital costs originate from EPRI and is based on the technology's development rating and design and cost estimate rating. The capital cost adjustment is applied to the process capital, general facilities and engineering fee components of the total plant cost. The adjustment to the heat rate is a 5% decrease and increase from the base heat rate to adequately represent improved or decreased operating performance of the technology over the designed heat rate. The fuel cost sensitivity was based on the Companies' August, 1999 Base, Low and High Fuel Cost Forecasts. As a result of the three possible values for each of the three sensitivity variables, 27 total possible scenarios exist for evaluation for each of the two cases.

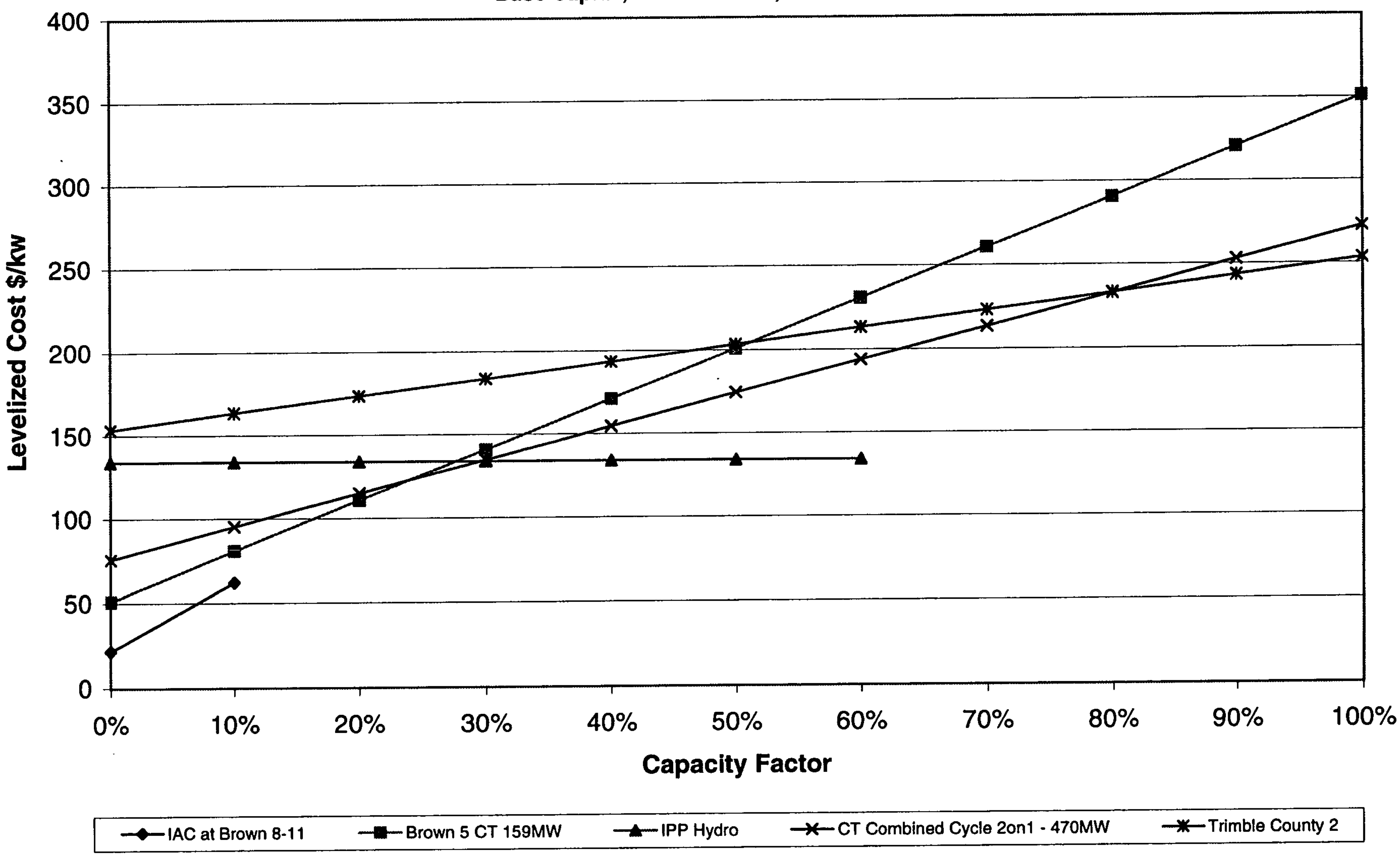
The 30-year levelized screening analysis determined the total annual cost of owning and operating each technology under each of the 27 scenarios and over a range of capacity factors from 0 to 100% in 10% increments. The 30-year levelized cost of each unit option over various capacity factor ranges is displayed in Table 8.(5)(c)-3 for the Base case combination of sensitivity variables. The shaded areas represent the least cost \$/kW-yr for each capacity factor level shown. Figure 8.(5)(c)-1 is a graphical representation of the Base case least-cost technologies identified in Table 8.(5)(c)-3. Annual capital cost of each unit is calculated using a fixed charge rate. Fixed and variable operation and maintenance costs are included and fuel cost is assumed to be a linear function of capacity factor.

Table 8.(5)(c)-3
Levelized Dollars at Various Capacity Factors

Capital Cost- Base *1999 Dollars ($/kW yr)*
Heat Rate- Base
Fuel Forecast- Base

	Capacity Factors										
Technology	***0***	***10%***	***20%***	***30%***	***40%***	***50%***	***60%***	***70%***	***80%***	***90%***	***100%***
Lead Acid Battery Storage(1 hr)-20MW	104	141	----	----	----	----	----	----	----	----	----
Advanced Battery (3 hr)-20MW	75	107	----	----	----	----	----	----	----	----	----
Advanced Battery (5 hr)-20MW	104	133	----	----	----	----	----	----	----	----	----
Pumped Hydro Energy Storage-350MW X 3	134	167	200	233	----	----	----	----	----	----	----
Compressed Air Energy (Salt Cavern) -350MW	70	98	125	153	----	----	----	----	----	----	----
Compressed Air Energy w/ Humid Air Turbine-350MW	60	87	114	140	----	----	----	----	----	----	----
Super Conducting Magnetic Energy Storage (2 hr)-500MW	101	128	----	----	----	----	----	----	----	----	----
Pulverized Coal (LSFO)-500MW	176	186	197	208	219	230	240	251	262	273	283
Pulverized Coal (LSFO)-400MW	196	207	217	228	238	249	260	270	281	291	302
Pulverized Coal (LSFO)-300MW	201	215	228	241	255	268	281	295	308	322	335
Pulverized Coal (LSFO)-200MW	245	256	267	278	289	300	311	322	333	344	356
Pulverized Coal (LSFO)-300MW X 2	180	191	201	212	222	233	244	254	265	275	286
Pulverized Coal Compliance (LSD)- 300MW	190	204	217	231	244	258	271	285	298	312	325
Pulverized Coal Supercritical (LSD)- 300MW	228	242	256	271	285	299	313	327	341	356	370
Pulverized Coal (Advanced LSFO)- 400MW	203	213	224	234	244	254	264	274	285	295	305
Atmosph Fluidized Bed (Circulating)-200MW	251	267	282	298	314	330	345	361	377	392	408
Press Fluidized Bed (Bubbling, Non-Reheat)-80MW X 2	276	288	300	312	324	337	349	361	373	385	397
Press Fluidized Bed (Bubbling)-350MW	192	203	214	225	237	248	259	270	281	292	303
Press Fluidized Bed (Bubbling, Supercritic)-340MW	190	201	212	223	233	244	255	266	277	288	299
Press Fluidized Bed (Circulating, with Reheat)-160MW	235	246	257	269	280	292	303	314	326	337	349
Press Fluidized Bed (Circulating, with Reheat)-360MW	177	188	200	211	222	234	245	257	268	279	291
Press Fluidized Bed (Circulating, Supercritical)-360MW	175	186	197	208	219	230	241	252	263	274	285
Foster Wheeler Advanced PFB (Circulating)-688MW	163	176	189	203	216	229	243	256	270	283	296
Highly Integrated Coal Gas/Comb Cyc (Entrained)-601MW	245	255	264	274	283	293	303	312	322	331	341
Int Coal Gas w/ Humid Air Turbine (Entrained Flow)-600MW	225	235	245	255	266	276	286	296	306	316	327
Int Coal Gas / CAES with Humid Air Turbine-410MW	251	262	273	284	295	306	317	328	339	350	361
Int Coal Gas/ Molten Carbonate Fuel Cell 400MW	338	351	364	377	391	404	417	430	444	457	470
Advanced Int. Coal Gas-460MW	177	189	201	212	224	236	248	259	271	283	295
Combustion Turbine Heavy Duty-80MW	70	105	140	175	210	245	280	315	350	385	420
Combustion Turbine Heavy Duty-110MW	61	98	135	172	209	246	283	320	357	394	431
Combustion Turbine Heavy Duty-160MW	56	87	118	149	180	211	242	273	304	335	366
Combustion Turbine Aero- 45MW	114	143	172	201	230	259	288	317	346	375	404
CT Combined Cycle 2on1 - 330MW	87	108	129	150	172	193	214	235	257	278	299
CT Combined Cycle 2on1 - 470MW	76	95	115	135	154	174	194	213	233	253	273
CT Combined Cycle - 345MW	79	99	118	138	157	176	196	215	234	254	273
CT with Cascaded Humidified Advanced Turbine-300MW	72	94	116	138	159	181	203	225	247	269	291
Phosphoric Acid Fuel Cell-2.5MW	1203	1231	1260	1288	1316	1345	1373	1401	1430	1458	1486
Molten Carbonate Fuel Cell-100MW	373	391	408	426	444	461	479	497	514	532	550
Solid Oxide Fuel Cell-100MW	187	204	220	236	253	269	285	302	318	334	351
Geothermal: Dual Flash Brine, Air Cooled-24MW	220	297	374	451	528	606	683	760	837	914	991
Solar Photovoltaic:Flat Plate-10x5MW	563	563	563	----	----	----	----	----	----	----	----
Solar Photovoltaic:One Axis Tracking Flat Plate-10x5MW	623	623	623	----	----	----	----	----	----	----	----
Solar Photovoltaic:Fresnel Lens High Concen.-10x5MW	578	578	578	----	----	----	----	----	----	----	----
Solar Thermal Trough/Gas Hybrid-200MW	390	394	398	----	----	----	----	----	----	----	----
Wind Turbines-Variable Speed-50x750kw	171	171	171	171	----	----	----	----	----	----	----
Wind Turbines-High Prod Volume-143x350kw	186	186	186	186	----	----	----	----	----	----	----
Wind Turbines-Class 4 Speed-50x750kw	145	145	145	145	----	----	----	----	----	----	----
Municipal Solid Waste: Mass Burn-40MW	945	980	1015	1049	1084	1119	1153	1188	1222	1257	1292
Municipal Solid Waste: Refuse Der.-40MW	1040	1075	1109	1144	1178	1213	1247	1282	1316	1351	1385
Municipal Solid Waste: Tire-30MW	595	600	605	610	614	619	624	629	633	638	643
Bio Mass: Wood-Fired Stoker Boiler-50MW	359	403	447	491	535	579	623	666	710	754	798
Bio Mass: Whole Tree-100MW	276	301	326	351	376	401	426	450	475	500	525
Cane Run 3 Rehab w/ AFBC	170	181	192	204	215	227	238	249	261	272	284
Cane Run 3 Rehab w/ Natural Gas	127	156	186	215	245	274	304	333	363	393	422
Brown 5 CT 110MW	54	88	122	156	190	224	258	292	326	360	394
Brown 5 CT 164MW	55	84	113	142	171	200	229	258	287	316	345
Brown 5 CT 102MW	57	91	125	159	193	227	261	295	329	363	397
Brown 5 CT 159MW	51	81	111	141	171	201	231	261	291	321	351
Brown 5 CT 149MW	52	82	112	142	172	202	232	262	292	322	352
IPP Hydro	134	134	134	134	134	134	134	----	----	----	----
Aeroderivative CT	52	85	118	151	184	217	250	283	316	349	382
Ohio Falls 9&10	149	149	149	149	----	----	----	----	----	----	----
Trimble County 2	153	163	173	183	193	203	213	223	233	243	253
IAC at Brown 8-11	21	62	----	----	----	----	----	----	----	----	----
Minimum Levelized $/kW	21	62	111	134	134	134	134	213	233	243	253

Figure 8.(5)(c)-1
Least Costly Technologies
Base Capital, Base Heatrate, Base Fuel



The first, second and third least cost alternatives over each capacity factor range were identified in all 27 scenarios. A total of 15 different technologies and technology types were initially identified as first, second or third least cost alternatives in the base case. After review, however, it was determined that several of these should be removed from the initial list.

The remaining technologies comprise the final list of technologies suggested for detailed analysis within PROSCREEN II. Table 8.(5)(c)-4 lists those technologies.

Table 8.(5)(c)-4
Technologies Suggested for Analysis
Within PROSCREEN II

Combined Cycle Combustion Turbine Phased – 470 MW
Combined Cycle Combustion Turbine Un-Phased – 330 MW
Combustion Turbine at Brown – 160 MW
Greenfield Site Combustion Turbine – 160 MW
Inlet Air Cooling at existing Brown CT's
IPP Hydro purchase
Pulverized Coal unit at Trimble County – 495 MW

Resource Optimization

In February 1999, the Companies issued a Request for Proposal (RFP) for the purpose of procuring peak capacity, in order to mitigate the capacity needs for the summer of 1999 and over the next few years. The RFP was sent to 107 potential suppliers including IOUs, electric cooperatives, large municipal organizations, and marketing entities. The RFP responses provided significant market data for summer 1999, and provided sufficient data for future summer periods to warrant further investigation of other resource options. Based upon the responses to the RFP and the fact that a resource need exists for the year 2000, the Companies began pursuing discussions with CT vendors and other companies on available options to meet the peaking requirements beginning in the summer of 2000 and beyond. As a result it appears unlikely that new CT capacity can be purchased and installed before the summer 2000. However, the Companies did begin negotiations with a local vendor for the installation of Inlet Air Cooling (IAC) for use with the existing E. W. Brown Units 8-11 CTs. The TES utilized ice storage to cool the inlet air of the combustion turbines. This capacity addition (approximately 80 MW) was built into the base data as an existing resource enhancement for inclusion in the integrated resource planning analysis.

The Companies continually analyze purchase power opportunities through the *Request for Proposal* (RFP) process and through participating in the wholesale marketplace on a real time basis. Currently peaking type purchase opportunities are compared to CT construction alternatives to arrive at an optimal strategy. Peaking type purchased power opportunities in optimizations would serve only to evaluate the delay of CT construction for short periods of time, which is already being considered in greater detail by the Companies' RFP process. Thus, peaking type purchased power was not considered in the integrated analysis. Likewise, because of computer run-time and storage limitations, certain logical restraints were implemented in PROSCREEN II. For example, each technology was reviewed and its earliest possible in-service date was established. With this and other logical constraints in place, a base case appropriate for optimization runs was ready.

In order to consider uncertainty in the process, a sensitivity analysis was implemented within optimization study simulations. The fuel forecast is one of the significant factors influencing the Companies' optimal integrated resource plan. Three fuel price sensitivities have been developed and were used in optimizations. It should be noted that no fuel sensitivities were considered for the hydro purchase option because it was considered representative of a firm offer. The load forecast is another significant factor influencing the Companies' integrated resource plan. In summary, the load sensitivity analysis consists of evaluating the effect of three load forecasts on the selection of resource alternatives. The three forecasts depict an expected system load growth case, a case where system load growth exceeds expected growth and a case in which system load growth is less than expected. For reference, the resulting forecasts are termed the base, high and low. The details of and the basis for the various load forecasts are described in Volume II, Technical Appendix.

The load forecasts together with the fuel forecasts result in the nine sensitivity scenarios used in the determination of the Companies' optimal integrated resource plan. "Scenario" will be used to describe a particular load forecast/fuel forecast combination. There are nine possible combinations of load/fuel scenarios, each of which were used in optimizations.

Computer run-time and storage limitations make it impractical to include the units which passed the supply-side screening analysis and those that passed the demand-side screening in a single unrestricted computer optimization run. Therefore, to facilitate the analysis and ensure that accurate results were obtained, additional steps were taken before optimizations were performed.

The first step was to separate the supply-side optimizations from the demand-side optimization runs. DSM projects tend to be small in nature and would only serve to delay the supply-side expansion strategy and not to change it. Therefore, supply-side optimizations were run and then another set of optimizations were performed in which DSM projects were allowed to compete against the supply-side options that were selected during the supply-side optimizations. This step greatly reduces computer run time without adversely affecting the integrity of the optimization process.

Another step taken was to constrain the evaluation of unreasonable combinations of units in PRV optimizations. One user-specified constraint in relation to new generating unit options is the earliest possible in-service date for each unit considered. The first year a technology was allowed to be considered as an alternative by PRV does not unjustly restrict the technologies but simply excludes years in which installation would not be feasible. For example, a coal-fired unit could not be permitted, constructed and operational within 5 years.

Additional steps are as follows:

- Only one CT was made available for installation at the E. W. Brown site. Other CTs must be constructed at a Greenfield site.
- Construction of a phased Greenfield combined cycle unit was limited so that the individual units were installed in the correct order (Phase 1 (CT), Phase 2 (CT), and then Phase 3 (HSRG)).
- The first combined cycle must be completed before a second one is started.
- The IPP Hydro based purchase option was modeled available for in-service between 2001 and 2003, and limited to one installation

Once the supply-side optimizations were complete, the next step was to evaluate the DSM programs against the selected supply-side options. This was accomplished by fixing the ordering of the supply-side alternatives in each plan and letting PROSCREEN II determine if it is economical to use any of the DSM options to delay the supply-side expansion plan. The DSM programs were broken down into phases to represent an expected penetration for the programs. The DLC program was set up as five phases with an approximately 22.1 MW peak reduction impact for each phase. The standby generation program was set up as four phases with a 20.6 MW impact each. The third program evaluated, the efficient lighting program, was set up in two phases of approximately 23.6 MW each.

The plans developed utilizing PROSCREEN II, both in the supply-side optimization and the optimizations with DSM included, are rank-ordered based upon the plans Present Value of Revenue Requirements (PVRR). The plan with the lowest PVRR is considered the optimal integrated resource plan.

A more detailed description of the process can be found in the report titled *Optimal Integrated Resource Plan Analysis* (October 1999) Volume III, Technical Appendix. The resulting plan is recommended for use as the Companies' 30-year integrated resource plan. It is further recommended that purchased power continue to be reviewed through the RFP process as an option to delay generation construction. The optimal plan through 2013 is shown below in Table 8.(5)(c)-5.

Table 8.(5)(c)-5
Recommended Plan

Year	Resource
1999	
2000	300 MW of Purchase Power
2001	160 MW Brown CT Unit 5 160 MW Greenfield CT Unit 1 160 MW Greenfield CT Unit 2 22.1 MW DLC program
2002	160 MW Greenfield CT Unit 3 22.1 MW DLC program 20.6 MW Standby Generation program 23.2 MW Efficient Lighting program
2003	22.1 MW DLC program 20.6 MW Standby Generation program 23.2 MW Efficient Lighting program
2004	160 MW Greenfield CT Unit 4 22.1 MW DLC program 20.6 MW Standby Generation program
2005	160 MW Greenfield CT Unit 5 22.1 MW DLC program
2006	160 MW Greenfield CT Unit 6
2007	160 MW Greenfield CT Unit 7
2008	160 MW Greenfield CT Unit 8
2009	160 MW Greenfield CT Unit 9
2010	160 MW Greenfield CT Unit 10
2011	160 MW Combined Cycle CT Phase 1
2012	160 MW Combined Cycle CT Phase 2
2013	150 MW Combined Cycle CT Phase 3

8.(5)(d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;

In August 1999 a study was completed which analyzed the Companies appropriate margin level. The base case series (base assumptions) from this study indicates that a 12% target reserve margin represents the greatest system reliability under the given set of assumptions. This study further indicated an 11%-14% range of reserve margin would provide a reliable system to meet customers' demand. Details of this study titled *Analysis of Reserve Margin Planning*

Criteria (October 1999) can be found in Volume III, Technical Appendix. The August 1999 study is summarized below and is a continuation of efforts to determine the reserve margin level that best balances reliability and cost.

The key variables for studies of this type are the number and length of planned generating unit outages and maintenance outages, generating unit forced/equivalent forced outage rates, the availability of purchase power capacity for import and the customers perceived cost of unserved/emergency energy. The availability of the Companies existing units is based on historical data. The availability of proposed generating units is such that it falls within the accepted availability for units of a given type, size and class. Since there is no industry standard for the cost of unserved energy, an EPRI study, adjusted to reflect recent market volatility was used to determine a base unserved energy cost. Sensitivity values around the base value of unserved energy cost were evaluated, as were market, load and unit availability sensitivities. The PROSCREEN II computer model was used in the evaluation and the minimization of present value of revenue requirements is the primary decision factor.

Optimization study runs were used to create a least costly ordering of supply-side options for various reserve margin levels (from 7% to 14%) given each set of key variables. This methodology was repeated for all possible combinations of the key variables over a range of reserve margins. Study cases run for reserve margins around the reserve margin associated with the minimum PVRR did not show a significant increase in PVRR. Therefore, cases with reserve margins that showed PVRR within a small variance of the minimum PVRR were considered as economically equivalent.

The base case assumptions used in this study, together with the detailed sensitivity analysis performed on the purchase power market and summer peak load, suggest an optimal reserve margin in the range of 11% to 14%.

8.(5)(e) Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;

The Companies will continue to develop ways to incorporate uncertainty into its analysis. Also, research will continue with regard to supply-side technologies, both with build and purchase opportunities. Specifically, the Companies plan to continually evaluate the economics of delaying near-term CT generation construction with economic purchase power opportunities. When possible this analysis will be conducted through the RFP process, which allows for a thorough analysis of current CT generation costs and purchased power costs.

8.(5)(f) Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and

The Acid Deposition Control Program was established under Title IV of the Clean Air Act Amendments of 1990. Acid deposition occurs when sulfur dioxide (SO_2) and nitrogen oxides (NO_x) are transformed into sulfates and nitrates and combined with water in the atmosphere and are then returned to the earth in rain, fog or snow. Title IV's purpose is to reduce the adverse effects of acid deposition through a permanent 10 million ton reduction in SO_2 emissions and a 2 million ton reduction in NO_x from 1980 levels in the 48 contiguous states.

Sulfur Dioxide (SO_2)

In Phase II of the Acid Deposition Control Program, effective January 1, 2000, the emission limits imposed on Phase I affected units (large units of 100MWs or more with high SO_2

emission rates of 2.5 lbs SO_2 /mmBtu or more) are tightened, and emission limits are imposed on smaller, cleaner plants as well. In general, all electric utility plants will have to reduce their SO_2 emissions to a level equivalent to 1.2 lbs SO_2 /mmBtu multiplied by their baseline heat input (average of the unit's 1985 through 1987 fuel use) divided by 2000. Electric utility plants are required to reduce SO_2 emissions to these prescribed levels or to acquire emission allowances from other sources. All of the Companies' generating units greater than 25 MW will become "affected units" on January 1, 2000 under Phase II of EPA's Acid Deposition Control Program.

Compliance with Phase I of the Clean Air Act Amendment of 1990 resulted in the installation of a flue gas desulfurization (FGD) system (scrubber) at KU's Ghent Unit 1 in 1995. The LG&E units were fully scrubbed and therefore were not Phase I affected units. The Companies' current Clean Air Act Compliance Plan consists of overscrubbing all existing scrubbed units beginning in 2000 and retrofitting a scrubber (FGD) on Ghent Unit 2 and fuel switching to high sulfur coal in 2003. Throughout 2000 the Companies will continue to evaluate the optimal scrubbing level of the existing scrubbed units in order to maximize the benefits to the ratepayers and shareholders. Additional detail on the Companies' compliance plan is included in a report titled *Clean Air Act Amendments of 1990 Compliance Plan, 1999 Environmental Compliance Analysis* (October 1999) Volume III, Technical Appendix.

Nitrogen Oxide (NO_x)

The Acid Deposition Control Program establishes annual emission limitations for NO_x based on boiler type to achieve NO_x emission reductions. Thus, the NO_x reduction program is not an allowance-based program. NO_x emission reduction controls must be in place when the affected unit is required to meet the SO_2 standard. The maximum allowable NO_x emission rates for Phase II are 0.40 lb NO_x /mmBtu for tangentially-fired boilers (in contrast to the Phase I limit of 0.45 lb NO_x /mmBtu) and 0.46 lb NO_x /mmBtu for dry bottom, wall-fired boilers (in contrast to the Phase I limit of 0.50 lb NO_x /mmBtu).

All of the KU affected units will comply with the Phase II NO_x reduction requirements through a system-wide NO_x emissions averaging plan (average Btu-weighted annual emission limit); compliance will be achieved through the installation of advanced low NO_x burners on Ghent 2, 3 and 4.

All of the LG&E affected units will comply with the Phase II NO_x reduction requirements on a unit-by-unit NO_x emission limitation basis. All of the LG&E units took advantage of the "early election" compliance option under the NO_x reduction program. EPA allowed these units to opt-in to Phase I for NO_x purposes and comply with Phase I NO_x emission limitations in order to be "grandfathered" from possibly more stringent Phase II NO_x limits. Under this regulatory provision, the LG&E Phase II NO_x affected units are allowed to demonstrate compliance with the higher Phase I limits from 1997 through 2007 and not meet the more stringent Phase II limits until 2008. If LG&E fails to meet this annual NO_x limit for each boiler during any year, the unit is subject to the more stringent Phase II NO_x limit beginning in 2000, or the year following the exceedance, whichever is later. Since all of the LG&E units "early elected" they are prohibited from operating under a NO_x emissions averaging plan and must comply on a stand-alone basis (each unit must meet its individual NO_x emissions limitation on an annual basis).

NO_x SIP Call

The NO_x SIP Call was promulgated under Title I of the Clean Air Act Amendments of 1990. Title I requires all areas of the country to achieve compliance with the National Ambient Air Quality Standards for ozone, or ground-level smog. In September 1998, EPA finalized regulations (the NO_x SIP Call) to address the regional transport of NOx and its contribution to ozone nonattainment in downwind areas. EPA's final SIP call requires 22 Eastern states (including Kentucky) and the District of Columbia to revise their State Implementation Plans (SIPs) to achieve additional NO_x emissions reductions that EPA believes are necessary to mitigate the transport of ozone across the Eastern half of the United States. The final rule is intended to assist downwind states so that they can achieve compliance with the ozone standard. EPA maintains that NO_x emissions from the identified states "contribute significantly" to nonattainment in downwind states, and that the SIPs in these States are therefore inadequate and must be revised by September 30, 1999. The final rule requires electric utilities in the 22- state area to retrofit their generating units with NO_x control devices by May 1, 2003. EPA set a utility NO_x budget in Kentucky of 37,000 tons of NO_x for the ozone season (based on an emission rate of 0.15 lb. NO_x /mmBtu for utility boilers or an 85% reduction from 1990 levels).

Eight states, the UMWA, and various industry groups have appealed EPA's final NO_x SIP Call rule to the U.S. Court of Appeals for the District of Columbia Circuit. The cases have been consolidated (State of Michigan v. EPA, No. 98-147) and the D.C. Circuit Court issued an order in December 1998 granting the parties' motion for expedited briefing to be completed by August 1999. On May 25, 1999, the D.C. Circuit issued an indefinite stay of the September 30, 1999 deadline for SIP submittal. Consequently, Kentucky has suspended their NO_x SIP submittal efforts. The D.C. Circuit has scheduled oral argument on the NO_x SIP Call case for November 9, 1999 with a final ruling expected by January - May 2000.

The Companies' portion of the Kentucky NO_x budget amounts to approximately 13,000 tons. The Companies have retained Sargent & Lundy to complete a system-wide NO_x compliance study. Sargent & Lundy's scope of work includes performing unit-specific feasibility analysis of NO_x reduction alternatives, analysis of the lowest cost compliance strategies, quantification of capital and O&M costs, identification of plant operational impacts, and a recommended implementation schedule. The Companies' goal is to develop a NO_x SIP Call compliance plan which results in compliance with the NO_x reduction requirements at the lowest combined capital and O&M life cycle costs across the Companies' generation fleet. The plan will aim to implement NO_x emission reduction technologies on a lowest "$/ton" of NO_x removed basis, so as to provide flexibility should regulatory or judicial changes affect the level or the timing of the NO_x reduction required. The Companies' NOx SIP plan will be filed in conjunction with a Certificate of Convenience and Necessity (CCN).

8.(5)(g) Consideration given by the utility to market forces and competition in the development of the plan.

In the development of the 1999 IRP, the Companies considered market forces and competition. This consideration is reflected in the appropriate sections of the IRP.

Table 9

Kentucky Utilities Company and Louisville Gas & Electric Company
Resource Assesment and Acquisition Plan
Financial Information

		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1	**Present Value of Revenue Requirements ($ million)**	[redacted]														
2	**Discount Rate**	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%	9.78%
	Inflation Rate	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%
3	**Real Value of Revenue Requirements ($ million)**	[redacted]														
	Nominal Value of Revenue Requirements ($ million)															
4	**Average Rate (Cents/kWh)**															

Note: Present Value and Real Value Revenue Requirements are in 1999$.
Note: Average Rate is Nominal Value of Revenue Requirements divided by total Energy Requirements from Table 8.(4)(b).
Note: Inflation Rate is average WEFA inflation rate based on CPI from 1999 through 2013.

9. FINANCIAL INFORMATION

Table 9 provides the Present (base year) value of revenue requirements stated in dollar terms for the 1999 integrated resource acquisition plan and the Nominal and Real Revenue Requirements (in $millions). The Average Rate for each of the forecast years included in the plan is defined as the Nominal Revenue Requirements divided by the total System Energy Requirements (in ¢/kWh) and is also included in Table 9.

The discount rate used in present value calculations is 9.78%. This value is the combined Company before-tax incremental weighted average cost of capital.

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

RECEIVED
NOV 1 5 1999
PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE JOINT INTEGRATED RESOURCE PLAN)
OF LOUISVILLE GAS AND ELECTRIC COMPANY) Case No. 99-430
AND KENTUCKY UTILITIES COMPANY)

MOTION TO INTERVENE

Comes the Attorney General, A. B. Chandler, III, pursuant to KRS 367.150 (8) which grants him the right and obligation to appear before regulatory bodies of the Commonwealth of Kentucky to represent the consumers' interests, and moves the Public Service Commission to grant him full intervener status in this action pursuant to 807 KAR 5:001(8).

/s/ Blackford

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4814

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that the original and ten copies of the foregoing were filed this the 15th day of November, 1999, with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and certify that on this same date true copies were served on the parties by mailing same, postage prepaid to:

Honorable Douglas Brooks

Senior Counsel Specialist
Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY. 40232 2010

/s/ Blackford

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

NOV 1 6 1999

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN	**)**	
OF LOUISVILLE GAS AND ELECTRIC COMPANY	**)**	**CASE NO. 99-430**
AND KENTUCKY UTILITIES COMPANY	**)**	

MOTION

Comes now the Kentucky Natural Resources and Environmental Protection Cabinet, Department for Natural Resources, through its Division of Energy, (hereinafter "NREPC"), by counsel, and pursuant to 807 KAR 5:001 Section 3(8), moves for leave to intervene in the above-styled case, and that it be granted full intervention status. In support of its motion, NREPC states as follows:

1. KRS 224.10-100(14) authorizes the NREPC to "advise, consult, and cooperate with other agencies of the Commonwealth";

2. KRS 224.10-100(28) authorizes the NREPC to "develop and implement programs for the development, conservation, and utilization of energy in a manner to meet human needs while maintaining Kentucky's economy at the highest feasible level";

3. The Division of Energy serves as the state energy office for Kentucky and administers a variety of programs designed to enhance the efficiency of energy production and use in all sectors of the economy;

4. In response to its legislative mandate, NREPC has worked for many years to maximize system-wide efficiency in the provision and use of electrical services through the mechanisms of integrated resource planning, least-cost planning, and demand-side management (DSM) programs offered through utility companies,

5. It has been the consistent goal of NREPC to minimize the total long-term societal costs of electric services;

6. If granted leave to intervene in this proceeding, NREPC can help ensure that the joint integrated resource plan filed by the Louisville Gas and Electric Company and Kentucky Utilities Company is consistent with the goal of minimizing the total long-term societal costs of electric services in the companies' respective service areas within Kentucky;

7. The NREPC has a special interest in this proceeding, its interest is not otherwise adequately represented, and with full intervention status, the NREPC will present issues and develop facts that will assist the Commission in fully considering this matter;

8. The NREPC being granted full intervention status will not unduly complicate or disrupt these proceedings;

9. The person designated to represent the NREPC in this proceeding is its Director of Energy:

John Stapleton
663 Teton Trail
Frankfort, Kentucky 40601
Telephone: (502) 564-7192

WHEREFORE, the NREPC respectfully prays for an Order granting it full intervention in this matter.

Respectfully submitted,

IRIS SKIDMORE
RONALD P. MILLS
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601
Telephone: (502) 564-6676

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing Motion was mailed, first class, postage prepaid, the 16th day of November, 1999, to the following:

Douglas Brooks, Esq.
Senior Counsel Specialist
Louisville Gas and Electric Company
220 W. Main Street
P.O. Box 32010
Louisville, Kentucky 40232-2010

David F. Boehm, Esq.
Boehm, Kurtz & Lowry
36 East Seventh Street
Cincinnati, Ohio 45202

Office of Attorney General
Division of Rate Intervention
P.O. Box 2000
Frankfort, Kentucky 40602-2000

Iris Skidmore

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

October 22, 1999

Honorable Douglas Brooks
Senior Counsel Specialist
Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY. 40232 2010

RE: Case No. 99-430

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell
Stephanie Bell
Secretary of the Commission

SB/sa
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 99-430

<u>O R D E R</u>

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") request that the Commission grant an extension of time from October 21, 1999 to November 22, 1999 to allow LG&E and KU to file their 1999 joint Integrated Resource Plan ("IRP") with the Commission. The request of LG&E and KU is made pursuant to Commission Regulation 807 KAR 5:058, Section 2(1)(c), which permits the Commission to modify utility IRP filing schedules "for good cause shown."

In support of their request, LG&E and KU state that due to significant participation by the Companies' Generation Planning Department personnel in other cases presently pending before the Commission, the Companies will not be able to file their joint IRP by the scheduled filing date of October 21, 1999. The Companies have contacted the Attorney General's Office of Rate Intervention and counsel for the Kentucky Industrial Utility Customers, the two parties who have participated in reviews of their past IRP filings, regarding this request. Both parties have indicated they have no objection to the request.

Upon consideration of the Companies' request and being otherwise sufficiently advised, the Commission finds there is sufficient justification to grant the request for an extension of time until November 22, 1999 to file their 1999 joint IRP.

IT IS THEREFORE ORDERED that LG&E and KU's joint IRP, previously scheduled for filing by October 21, 1999, shall be filed on or before November 22, 1999.

Done at Frankfort, Kentucky, this 22nd day of October, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

Law Department

Louisville Gas and Electric Company
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232
502-627-3450
502-627-3367 FAX

October 14, 1999

VIA OVERNIGHT DELIVERY

Helen Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602

RECEIVED
OCT 15 1999
PUBLIC SERVICE COMMISSION

CASE 99-430

Re: Louisville Gas and Electric Company and Kentucky Utilities Company Joint Integrated Plan, Case No.

Dear Ms. Helton:

You will find enclosed for filing in the above-referenced case an original and ten (10) copies of a Motion For Extension of Time to File Joint Integrated Resource Plan for Louisville Gas and Electric Company and Kentucky Utilities Company. A copy of this letter and motion have also been mailed to counsel for the Attorney General and to counsel for Kentucky Industrial Utility Customers, as indicated on the Certificate of Service.

Please contact the undersigned if you have any questions. Thank you for your courtesies in this matter.

Sincerely yours,

Douglas M. Brooks
Senior Counsel Specialist, Regulatory
(502) 627-2557

DMB:bjl

Enclosures

RECEIVED
OCT 15 1999
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE JOINT INTEGRATED INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	Case No. 99-430

MOTION FOR EXTENSION OF TIME TO FILE JOINT INTEGRATED RESOURCE PLAN

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") hereby move the Commission for an extension of time to file their joint Integrated Resource Plan ("IRP") by thirty-two (32) days, or from October 21, 1999 to November 22, 1999, and in support thereof states the following.

1. By Order issued October 9, 1998, the Commission required LG&E and KU to file their first joint IRP by October 21, 1999. This IRP will reflect the joint generation planning conducted by the Companies after the merger of their respective holding companies on May 4, 1998.

2. Since the merger, the Companies have diligently performed the work necessary for the preparation of their joint IRP. However, due to the press of other business, in particular the significant participation by the personnel of the combined Generation Planning department in the Companies' pending Performance-Based Ratemaking cases (Case Nos. 98-426 and 98-474) and the Kentucky Industrial Utility Customers' ("KIUC") Complaint cases (Case Nos. 99-082 and 99-083), the Companies will not be able to complete and file their joint IRP by October 21, 1999. An extension of time of approximately thirty (30) days will enable the Companies to

complete their IRP filing. November 22, 1999 is the first working day after thirty (30) days past October 21, 1999.

3. Counsel for the Companies has discussed this request for an extension of the filing deadline with counsel for the Attorney General's Rate Intervention Unit and for KIUC. Both parties have authorized the undersigned to represent to the Commission that they have no objection to this Motion.

4. The extension will enable the Companies to provide the Commission with a full and complete IRP without undue delay or prejudice to any party.

WHEREFORE, LG&E and KU request that the Commission extend the time to file their joint Integrated Resource Plan ("IRP"), by thirty-two (32) days, or from October 21, 1999 to November 22, 1999.

Respectfully submitted,

Douglas M. Brooks
Senior Counsel Specialist, Regulatory
LOUISVILLE GAS AND ELECTRIC COMPANY
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232
(502) 627-2557
Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

CERTIFICATE OF SERVICE

This is to certify that a true copy of the foregoing instrument was mailed, first-class, pre-paid, on October 14, 1999, to:

Michael Kurtz
Boehm, Kurtz and Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, OH 45202

Elizabeth Blackford
Assistant Attorney General
Utility and Rate Intervention Division
P.O. Box 2000
Frankfort, KY 40602-2000

DMBrooks

Douglas M. Brooks

RECEIVED
JUN - 5 2000
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN)
OF LOUISVILLE GAS AND ELECTRIC COMPANY) CASE NO. 99-430
AND KENTUCKY UTILITIES COMPANY)

KENTUCKY DIVISION OF ENERGY'S COMMENTS RELATED TO THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

I. INTRODUCTION

This analysis prepared by the Kentucky Division of Energy (KDOE) has several purposes:

1) to recognize certain ways in which the 1999 joint integrated resource plan (IRP) developed by the Louisville Gas and Electric Company and Kentucky Utilities Company (the Companies) represents a significant advance compared to IRPs submitted by the individual companies in previous years;

2) to raise an issue about the fundamental purpose of integrated resource planning, concerning which we hope the Commission will provide future guidance;

3) to comment on the methods the Companies used to identify and analyze resource options; and

4) to suggest a number of market-oriented strategies that we believe the Companies should consider in addition to those described in the 1999 IRP.

KDOE believes that the strategies, programs, and analytical methods we will suggest are consistent with the rationale underlying integrated resource planning, and that they offer significant profitable long-term opportunities for the Companies and their shareholders as well as tangible economic benefits for their customers.

Most of the comments contained in this analysis relate to demand-side resources, distributed generation, and new approaches to meet customer needs that the Companies may wish to incorporate into their plans. The 1999 IRP is noteworthy in that it includes substantially greater attention to and investments in demand-side resources than any of the IRPs submitted by LG&E or Kentucky Utilities in the past. The demand-side management (DSM) analysis found in Volume III, Section IV represents a significant level of effort by company staff. The major DSM programs proposed – direct load control and the use of standby generation equipment – contribute to an energy marketplace that functions better by aligning the price signals faced by participating customers with those faced by the Companies.

Another development that KDOE views as positive is the establishment in recent years of an energy service company by LG&E, which operates both within the Companies' service territories and beyond. This non-regulated company, called LG&E Enertech, helps customers obtain more net value from the energy they purchase, and helps overcome some of the most important barriers that prevent customers from optimizing the efficiency of their facilities: lack of information, lack of financing, and inaccurate perceptions about the technical risk of energy efficiency retrofits.

Although KDOE will be pointing out certain problems we see in the Companies' screening methodology, it is important to emphasize that the overall trend in regard to the use of demand-side resources, as reflected in the 1999 IRP, is in a positive direction.

II. THE PURPOSE OF INTEGRATED RESOURCE PLANNING

Through requests for information from KDOE and the Companies' responses, it became clear that there is disagreement about whether the purpose of integrated resource planning is to minimize the utility's present value revenue requirements (PVRR) – which is equivalent to using the Utility Cost (UC) test – or to minimize the total resource costs (TRC) of providing energy services.[1] This issue arises during the final step in the IRP process, when supply-side and demand-side options are compared and integrated into a plan for future resource acquisitions. The Companies claim that minimization of the PVRR "is the accepted method to developing optimal integrated resource plans,"[2] while KDOE believes that the TRC test should be the primary criterion.

The first paragraph of 807 KAR 5:058 (Necessity, Function, and Conformity) calls for utility resource plans "to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers within their service areas..."

The reference book, *Demand-Side Management Planning*, by Clark W. Gellings and John H. Chamberlin, describes the TRC test as follows:

> "The Total Resource Cost (TRC) test is a measure of the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers as a whole. Resource costs include changes in supply costs, utility costs, and participant costs. Since the utility and its ratepayers are taken as a whole, changes in the dollar amounts that flow between them (transfer payments) are ignored (e.g., incentives and revenue changes are ignored). **This test is also called the All Ratepayers test.**"[3] [emphasis added]

In contrast, the Utility Cost test leaves the net savings of participants (all of whom are "ratepayers") out of the equation. KDOE believes that the TRC, or All Ratepayers test, more closely conforms to the intent and language of 807 KAR 5:058 than the UC test or PVRR.

The same book discusses the origins of integrated resource planning as follows:

> "A combination of economic and environmental imperatives have created strong regulatory and legislative interest in developing a truly integrated planning process that takes a broad view of the factors involved in serving societal energy needs."

[1] Companies' responses to KDOE Questions #20 and #25, 1st set and Question #4, 2nd set.
[2] Companies' response to KDOE Question #4, 2nd set.
[3] Gellings and Chamberlin, *Demand-Side Management Planning*, 1993, Fairmont Press, p. 260.

The next paragraph defines least-cost planning:[4]

> "Least-Cost Planning (LCP) is the process of selecting the mix of generation options, demand-side management measures, purchases, and sales that enable a utility to meet society's energy needs at the lowest overall cost subject to a variety of constraints, such as minimizing economic and environmental risks. Least-cost planners attempt to evaluate the potential available through efficiency improvements, load management and nonutility energy sources on an equal footing with power plants." (Reference: "Moving Toward Integrated Resource Planning: Understanding the Theory and Practice of Least-Cost Planning and Demand-Side Management," EM-5065, February 1987, EPRI.)

KDOE concludes from this discussion that the purpose of integrated resource planning is the same as least-cost planning: to evaluate supply-side and demand-side resource options on an equal basis, and to arrive at an integrated plan that meets all customers' energy needs at the lowest overall cost. This is not the same as minimizing the PVRR, which focuses exclusively on the utility company's costs and leaves the net savings to participating customers out of the analysis.

It should be noted that this is not the first time this issue has been brought to the Companies' attention. During the summer of 1999, in the context of the performance-based regulation case (Case Numbers 98-426 and 98-474), KDOE engaged in a process of negotiation with the Companies that included the topic of the proper role of integrated resource planning. KDOE and the Companies eventually agreed on certain principles and commitments which were reflected in a "Letter Agreement" dated July 28, 1999. Although the agreement was excluded from the case record by order of the Commission (on the grounds that it was not an agreement by and among *all* of the parties to the case), KDOE believes it to be appropriate to quote the section of the letter that relates to integrated resource planning. The following excerpt reflects concepts that the Companies (called "Applicants" below) were at one time willing to accept, within the context of the other terms and provisions that made up the complete Letter Agreement:

[4] *Ibid.*, p. 11.

"A. *Guiding Principles Endorsed by the Applicants and KDOE*:

"A guiding principle in integrated resource planning is that the least-cost strategy for the electric system as a whole can be best achieved through a combination of cost-effective actions on the demand and supply side.

"In the development of their joint Integrated Resource Plan (the "Joint IRP"), the Applicants should have an equivalent financial incentive to invest in new demand-side and new supply-side resources.

"B. *Demand Side Management Planning and Cost Recovery*

"LG&E and KU shall use their joint Integrated Resource Plan (the "Joint IRP") to be filed with the Kentucky Public Service Commission in the Fall of 1999 to evaluate cost-effective demand and supply options, including, but not limited to energy efficiency and load shifting measures and renewable energy generation. Such supply and demand options will be evaluated on a consistent financial basis in the IRP.

"In preparing the Joint IRP, LG&E and KU shall study the technical potential for cost-effective energy efficiency and load-shifting measures and renewable energy generation by customers in the service territories, the cost of implementing these measures, and the revenue requirements that would be needed to acquire various portions of these potential resources through utility DSM programs. The Total Resource Cost (TRC) test shall be the primary cost effectiveness test used to screen and rank alternative DSM technologies, measures, and programs. The other Standard California Benefit/Cost tests shall be calculated and taken into consideration as well. The Rate Impact Measure (RIM) test shall not be used to screen out DSM technologies, measures, or programs."[5]

We believe that the provisions excerpted above indicate that the Companies at one time were in agreement with KDOE about the general purpose and methodology of integrated resource planning. Although we are aware that subsequent events nullified the enforceability of the Letter Agreement, we see no reason why the Companies' perspective on the purpose of integrated resource planning should have changed between July 1999 and the present date.

The principles endorsed by the parties to the Letter Agreement are consonant with the Public Utility Regulatory Policies Act of 1978 (PURPA), as amended by the Energy Policy Act

[5] Letter Agreement Between the Companies and KDOE, July 28, 1999, pp. 1-2.

of 1992, Section 111. Federal law now requires all electric utilities to employ integrated resource planning. It also states: "The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment."[6] KDOE believes that there is close correspondence between this statutory language and the concepts reflected in the portion of the Letter Agreement quoted above.

If the Companies are correct when they state that minimization of the PVRR is the "accepted method" for developing optimal integrated resource plans, KDOE believes that this method has diverged from the original purpose of least-cost planning and integrated resource planning. We also believe that this method has diverged from the intent of 807 KAR 5:058, which specifically requires planning to meet future demand "at the lowest possible cost for all customers." While the method of minimizing the PVRR (i.e., the utility cost or UC) might be accepted in other jurisdictions outside Kentucky, KDOE believes that the Commission should provide guidance on this issue to help utilities develop their future IRPs in a way that maximizes the planned benefits to all Kentucky ratepayers.

III. KDOE'S VISION OF THE FUTURE: A WELL-FUNCTIONING MARKET FOR ENERGY SERVICES

KDOE supports the increasing role of competitive markets and customer choice in the electric utility industry, because we believe that if the markets in energy services are properly structured, competitive forces will be unleashed that will give rise to truly phenomenal efficiency

[6] 16 USC Sect

gains within the energy sector. The characteristics of a better-functioning market are described below.

Pricing signals would serve as the primary determinant for energy-related decisions. Customers would have, or could obtain, adequate information about the life-cycle costs and benefits of their purchasing and investment decisions. Customers would be less concerned about the price of each kWh of electricity than about the size of their energy bills and the net value that various competing packages of energy services could provide to their businesses or homes. Businesses would apply the same financial criteria (payback periods or return-on-investment "hurdle rates") to cost-reducing investments as they do to investments that promise to increase sales. In transactions involving multiple parties, accurate information about future energy costs would be reflected in negotiated contractual arrangements, so that those parties bearing the costs of energy upgrades would be compensated by those parties enjoying the benefits. Designers who take the extra time necessary to improve the efficiency and performance of their buildings would be compensated for their efforts by their clients. Financing would be available at market rates for cost-effective energy upgrades. A sufficient number of sellers would exist to create a competitive market for energy services. Electricity prices would approach marginal costs, which would change throughout the day and year because of generation, transmission, or distribution system constraints, thus passing price signals on to customers and other market participants. Government policies would monetize external environmental effects at societally efficient rates, or at least there would be a functioning market for "green power." There might be a functioning market in saved energy, or "negawatts,"[7] in Amory Lovins' phrase.

[7] "Saving Gigabucks with Negawatts," Amory B. Lovins, *Public Utilities Fortnightly*, March 21, 1985, pp. 19-26.

While we recognize that the scenario described above can never be realized in its entirety, we believe that public agencies should promote policies that support the functioning of markets under ideal competitive conditions to the extent possible.

IV. THE PRESENT REALITY: PERVASIVE AND CHRONIC MARKET BARRIERS

In stark contrast to the idealized competitive market for energy services described in Section III above, present-day markets are riddled with barriers that prevent customers from obtaining the most economically advantageous energy services available to them. The potential efficiency gains that these market barriers prevent are very large, as illustrated by the following discussion focusing on the commercial building sector.

A 1992 Strategic Issues Paper produced by E Source posits that "Well over half of the energy used to cool and ventilate buildings in countries like the United States can be saved by improvements that typically repay their cost within a few years." Other analyses have found comparable potential savings in lighting, drivepower, office equipment and other end-uses. The report continues, "To a theoretical economist, these are astounding statements: it is inconceivable that in a market economy, such large and profitable savings would remain untapped. But to a practitioner who knows how buildings are created and run, it is not only conceivable but obvious."[8] The rest of the report provides a detailed examination of the process by which buildings are designed, built and operated, and how inefficiencies are introduced at every stage through practices which are typical in the commercial construction market. Most of the barriers result from split incentives, perverse incentives, lack of information, and lack of communication between the numerous parties involved. Although each market participant may be behaving

[8] "Energy-Efficient Buildings: Institutional Barriers and Opportunities," E Source, Inc., 1992, Boulder, Colorado, p.6.

rationally within his or her narrow area of responsibility, the overall result is a system that chronically undervalues energy efficiency. Some causes of the chronic market failure in the field of new commercial construction are listed below:

- Real estate developers and investors, who make early building decisions, discount energy-related issues heavily, focusing on minimizing construction time and cost.
- U.S. rules on taxes and depreciation exacerbate the focus on first cost.
- Developers have very little information about the efficiency gains that are possible.
- Financial institutions may reject innovative designs, fearing delays in approval by code officials.
- Commercial appraisers and securities rating agencies know little about energy and have no way to evaluate designers' projections of energy performance.
- Site planning decisions may be made by professionals with little knowledge of energy before an architect is even hired, despite the fact that "Just proper choice of architectural form, envelope, and orientation can often save upwards of a third of the building's energy at no extra cost – 44% in one recent California design."[9]
- Most architects do not know enough about mechanical systems design and do not work very closely with the HVAC professionals – especially during the earliest phases of design, when decisions have the largest impacts.
- Mechanical designers and equipment vendors have economic incentives to oversize systems.
- Few HVAC designers perform dynamic thermal simulations; many use rules of thumb, and some leave system sizing decisions to the equipment manufacturers.
- The emphasis on "just-in-time" design leaves little time for optimizing whole systems.
- Most often, no single member of the design team has overall responsibility for the entire interactive system. Even if an interdisciplinary team approach is desired, each profession communicates using different terms and has different incentives, making cooperation difficult.
- Design fees are not structured to compensate for the extra time needed to optimize systems; in fact, fee structures reward speed above all.

[9] Ibid., p.11.

- Architects and designers often handle potential liability concerns by oversizing equipment, but the client is left with higher capital and operating costs.

- Construction contractors frequently substitute less efficient equipment for what may have been specified; designers are usually not present to catch discrepancies or errors.

- Commissioning of the building's mechanical systems is rarely performed to make sure they work as specified.

- Thorough documentation on how to run a building optimally is not provided to building operators.

- Although much HVAC equipment fails to meet its specified capacity and efficiency ratings, measurement that could catch such discrepancies is not done.

- Building operators are not trained in or rewarded for energy-efficient operation, and may frequently disable automatic control systems to minimize complaints.

- The actual performance of HVAC systems in the field is often never monitored directly. The lack of actual data makes it difficult to know how best to improve their operation.

- Suppliers of parts and replacement equipment are not rewarded for selling high-efficiency products.

- Commercial leasing brokers are unfamiliar with energy, and tend to use rules of thumb rather than building-specific analyses.

- Commercial leases do not provide both parties an incentive to cooperate to implement energy efficiency upgrades.

- Few commercial tenants know enough about energy efficiency to demand it in the market.

Given this (non-exhaustive) list of barriers in the new commercial construction market, it should not be surprising when analysts reach the conclusion that huge gains in energy efficiency are technically feasible at very reasonable cost. The Environmental Energy Technologies Division of the Lawrence Berkeley National Laboratory estimates that "If only tune-ups and performance monitoring of existing buildings were performed, average energy use could be reduced by about 20%. If proven efficiency measures were applied when a building is retrofitted (usually about every 15 years), about 50% reduction could be attained. The full range of efficiency measures that can be designed and incorporated into new buildings could bring about an energy reduction of as much as 75%."[10] Other estimates (for example, by E Source) are even higher. The fact that a long list of market barriers exists does not mean that they could never be overcome through carefully designed programs and policies.

Savings of a similar magnitude are obtainable in the residential sector as well. The U.S. Department of Energy's *Building America* program is applying whole-building principles to new home construction and reducing energy use by approximately 50%, at little or no additional cost to production builders in a range of climate zones.

The Rocky Mountain Institute describes a case study of what can be done in the residential sector by a utility company that is seriously interested in exploring the potential energy savings resulting from whole-system design. The Pacific Gas and Electric Company, as part of its Advanced Customer Technology Test (ACT^2) program, hired the Davis Energy Group to improve an initial design for a house that already met California's strict Title 24 energy code, which is supposed to include all efficiency measures that are worth buying from a societal perspective. The first step was to eliminate unnecessary corners that had added 23 feet (11%) of length to the outside walls. The designers then put the windows in the right places, used window frames that would transmit less heat, and invented an engineered wall that saved about 74% of the wood, reduced construction costs, and nearly doubled the insulation. A number of small improvements to the building envelope, windows, lights, major appliances, and hot-water system raised the total energy saving to 60% and increased the cost by nearly $1,900. At the same time, however, the thicker insulation and better windows eliminated any need for the $2,050 furnace and its associated ducts and equipment. Instead, on the coldest nights, a small amount of hot

[10] Lawrence Berkeley National Laboratory, "Creating High-Performance Commercial Buildings," *EETD News*, Fall 1999, pp. 1-2.

water from the 94%-efficient gas-fired water heater could be run through a radiant coil cast into the floor-slab. Finally, the designers eliminated the air conditioner by adding several more efficiency measures that had not previously appeared to have been cost-effective based on a conventional (measure-by-measure) analysis. The report concludes as follows:

> "Factoring out small electrical appliances (one-third of initial electricity usage), which offered many savings opportunities but would be brought along by the buyer rather than installed by the builder, the resulting final design would save about 80% of total energy or 79% for electricity alone: 78% for space heating, 79% for water heating, 80% for refrigeration, 66% for lighting, 100% for space cooling, and 92% for space cooling plus ventilation. If such construction techniques became generally practiced – so-called "mature-market cost" – then those savings would make the house, in a mature market, cost about $1,800 less to build and $1,600 less to maintain.
>
> "The measured savings, adjusted for some last-minute design changes requested by the homebuyer, agreed well with these predictions. The house proved very comfortable even in a severe hot spell. Since by law the Title 24 code is supposed to include all cost-effective measures, the Davis house may mean that this influential state standard has to be rewritten from scratch."[11]

If the Companies were interested in applying this approach in Kentucky, it might be possible to develop marketable house designs that replace the central furnace by a water-heater based system – home builder Perry Bigelow has done so in the Chicago area – and downsize or eliminate the conventional air conditioning system.

Similar examples can be cited in the industrial sector. A major use of electricity in industry is to operate pumps for moving liquids around. The carpet company, interface, was planning to build a new factory. One of the factory's processes required 14 pumps. A leading firm specializing in factory design sized the pumps to total 95 horsepower. An Interface engineer, Jan Schilham, however, took a fresh look and was able to come up with a design that was not only more efficient but cost *less* to build. The first change used larger pipes and smaller

[11] Rocky Mountain Institute, "Designing For Zero Cooling Equipment in a Hot Climate," 1999, www.naturalcapitalism.org/sitepages/pid27.asp

pumps, greatly reducing frictional losses. Second, Schilham laid out the pipes first and then the equipment, in the reverse order from standard practice, enabling him to use shorter and straighter pipe runs. The combination of these two approaches allowed for a system with only 7 horsepower of pumping capacity – a 92% decrease. The lower capital cost of the smaller pumps, motors, inverters, and associated electrical system more than compensated for the additional cost of larger diameter pipes. The payback period for the higher-efficiency system was instantaneous and its return on investment was infinite because it was cheaper than the inefficient design. However, "optimization" techniques in use throughout the industrial sector routinely ignore systemic effects such as these, focusing only on single-component or partial-system optimization.[12]

These examples illustrate an important point about whole-system design: It is frequently more cost-effective to save large amounts of energy than small amounts. It can make sense from a whole-system perspective to make certain components *more* efficient than a component-by-component "optimization" approach would suggest. This surprising phenomenon, called "tunneling through the cost barrier," results from capital cost reductions (e.g., smaller or no HVAC systems, smaller pumps) that can be added to the energy savings. "Optimizing components in isolation tends to pessimize the whole system."[13]

In conclusion, the market barriers to efficient design in all sectors of the economy – residential, commercial, and industrial – are large and long-standing. They can, however, be addressed and overcome through well-focused programs that involve a range of participants, including the utility company. We will describe a number of such "market transformation" concepts in Section VI below.

[12] Hawken et al., *Natural Capitalism*, pp. 116-117.
[13] *Ibid.*, p.117.

V. THE COMPANIES' INTEGRATED RESOURCE PLAN

In assessing the Companies' 1999 IRP, KDOE identified certain problems related to the method used to identify and screen demand-side management (DSM) options.

1. Limited Number of DSM Options Considered

While a "Long List" of 82 DSM alternatives may seem to be extensive, some of the items are included multiple times. Seasonal Rate Differential, Demand Subscription, TOD Rates, Thermal Energy Storage, Education and High Efficiency Lighting are listed in all three customer classes, and several alternatives are listed in two classes. A number of "DSM alternatives" – Fuel Cells, Micro Turbines, Reciprocating Engines, Stirling Engines, Photovoltaics, and Windmills – are actually supply options (but might be included in a DSM list under the rubric of "distributed generation"). When redundancy is eliminated, the number of discrete, demand-side alternatives in the "long list" is closer to 50.

The Rocky Mountain Institute has published a technical potential supply curve based on measured installed technical cost and measured performance of approximately 1,000 commercially available demand-side technologies in 1989.[14] E Source, which is a spinoff company from the Rocky Mountain Institute, periodically updates this information and provides it for a fee to organizations that subscribe to its services. Detailed data is available on a large number of demand-side technologies, eliminating the need for the Companies to perform extensive original research. KDOE does not mean to imply that a list of DSM technologies must have 1,000 items for it to be comprehensive, but we are concerned that the Companies may have overlooked a large number of promising technologies in their 1999 IRP.

[14] Lovins, Amory, "Apples, Oranges, and Horned Toads: Is the Joskow & Marron Critique of Electric Efficiency Costs Valid?", *Electricity Journal*, May 1994, p. 36.

2. Category Confusion

Some of the alternatives listed are individual demand-side technologies, e.g., Low-E Windows, Setback Thermostats; some are supply technologies, e.g., Photovoltaics; some are program concepts, e.g., Refrigerator Replacement, Direct Load Control; some are ideas for tariffs, e.g., Time-of-Day Rates; and some are collections of technologies, e.g., Efficient Construction (residential), High Efficiency Cooling, Compressed Air System Upgrade. The Companies lumped all of these disparate types of things together into one list and then tried to apply a single screening method to compare them all. KDOE is concerned that such a methodology may have generated results that are not as meaningful as they could be.

3. Faulty Screening Methodology

The Companies used a two-step screening process to reduce the number of DSM alternatives to a level they felt was manageable. The first step was a qualitative screening method that used four weighted criteria and generated a single numerical score for each alternative.[15] KDOE has identified serious problems with every one of the criteria used.

a. Customer Cost (weight = 20%)

As was established through KDOE's Information Request #1-13 and the response, the cost which a customer must pay to participate in a DSM program is largely a function of the way the program is designed and administered. If the utility pays a higher fraction of the cost of installing a certain technology, the cost to the customer will be correspondingly reduced. Because customer cost is not an inherent property of a technology, the criterion becomes subjective and less than adequate as a way to screen alternatives.

b. Customer Acceptance (weight = 30%)

[15] 1999 IRP, Volume III, Section IV, Exhibit DSM-2 and pp. IV-1 to IV-2.

The same point – that to a large degree the design of a DSM program affects customer acceptance – was made in KDOE's Information Request #1-15 and the response. In addition, in the absence of market research data or customer surveys, the numerical rating of alternatives becomes highly dependent on the subjective feelings of the Companies' analysts about how customers might react.

An example of such subjectivity is the rating of 2 given to Construction Building Standards (commercial). This alternative was defined as follows: "Construction building standards would work to implement new building standards that require energy efficient building practices and measures."[16] New building standards, or energy codes, would apply to all commercial customers as a matter of law. While customers might resent the imposition of more stringent energy codes by the governing building authority, there would be no impact on the number of customers participating, which would be fixed at 100% of all new buildings within the geographical area governed by the code. (Moreover, most customers would probably be unaware of any utility company role in the strengthening of the building code, so any ill will caused by the standards would be directed at the government, not the Companies.) Because participation is fixed at 100%, KDOE sees no reason why the Customer Acceptance rating for Construction Building Standards (commercial) should be anything other than 4.

Another example of apparent subjectivity is the rating of 1 given to Photovoltaics (residential). The issue of cost can be set aside because it is covered by the first criterion. Photovoltaic (PV) modules – installed on a home and interconnected with the electric grid to avoid the need for energy storage in batteries – are extremely reliable, featuring no moving parts and service lifetimes of at least 15 to 20 years; can be installed in a way that maintains safety and has no effect on occupants' comfort or convenience; operate completely without noise; and can be made to look like roofing shingles, which would meet any aesthetic concerns. When utilities such as the Sacramento Municipal Utility District offer PV to residential customers, they are able to charge higher than normal rates because customers want to support "green power" and enhance their status by being among the first to have solar electric panels on their home. KDOE sees no reason why the Customer Acceptance rating for residential PV should be anything other than 4. The rating should arguably be 5, exceeding the allowable range because many customers would prefer the technology to the standard one.

KDOE concludes that "Customer Acceptance" is largely a function of DSM program design and is too subjective to be useful as a screening criterion, if market research data is unavailable.

c. Maturity of Technology/ Data Confidence (weight = 20%)

This criterion is composed of two different concepts that were later combined. According to the Companies, "The higher the rating for the Maturity of Technology/ Data Confidence criterion, the more likely the technology is commercially available and proven, and there is reliable load and market data available."[17] An unfortunate corollary is that the more mature a technology is, the closer it will be to standard practice. This criterion creates a strong bias against newer technologies and design methods that may have greater energy impacts when compared to what is presently being done. KDOE is concerned that the use of this criterion contributes to the selection of mediocre DSM programs instead of the best that could be implemented.

In contrast, a market transformation approach would focus preferentially on relatively new technologies, combinations of technologies, or design methods that work, but which have

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[16] Companies' response to KDOE's Question #1-6(i).
[17] Companies' responses to KDOE's Questions #1-16 and #1-17.

not yet achieved widespread acceptance in the market. This approach will be considered in greater depth in Section VI below.

d. Meets Load Shape Objectives (weight = 30%)

This criterion is defined as follows: "Does the measure have the ability to reduce the seasonal coincident peak demand or increase the annual system load factor?"[18] The objection KDOE has to this criterion is that it serves as a qualitative proxy for the Rate Impact Measure (RIM) test. If all other factors are held equal, a measure that better meets the Companies' load shape objectives will score higher on the RIM test, and conversely. Thirty percent of the weight in the Companies' screening methodology is thus being given to a criterion that closely tracks the RIM test.

KDOE has consistently held that the RIM test should not be used to screen out DSM programs because supply-side options are not screened in the same way. To apply an additional, very stringent requirement to demand-side options biases the IRP process strongly in favor of the supply side, and defeats one of the key purposes of integrated resource planning. In addition, when the RIM test is used to compare DSM programs against each other, it introduces an unacceptable degree of bias in favor of load shifting programs and against programs that save energy. KDOE made these points to the Companies last summer in the context of the PBR case, and the Companies agreed to include a sentence in the Letter Agreement stating, "The Rate Impact Measure (RIM) test shall not be used to screen out DSM technologies, measures, or programs." Because the load shape criterion has the same effect as the use of the RIM test, KDOE considers it inappropriate. (KDOE is not claiming that the Companies intentionally selected this criterion in order to introduce the RIM test covertly, but only that the criterion has the same effect as the RIM test in practice.)

If our contention is correct that every one of the criteria used by the Companies in their qualitative screening process has serious flaws, then there is no reason to think that the DSM programs selected for further consideration are the best alternatives available. While KDOE commends the Companies for expending the considerable effort needed to analyze a range of DSM options and for including significant new DSM programs in their IRP, we have little confidence that the best options were considered or selected.

5. Excessively Stringent DSM Screening Cutoff Point

KDOE shares the concern expressed by the representatives of the Attorney General's Office at the informal conference that too high a proportion of the DSM alternatives was screened out during the first phase. If the qualitative screening methodology is fundamentally flawed, however, this point would become somewhat moot.

6. Supply-Side Screening Problem

KDOE shares the concern expressed by the representatives of the Attorney General's Office at the informal conference that the supply-side screening methodology does not appear to account properly for technologies with zero fuel costs. Additional comments on the issue of the proper valuation of distributed generation technologies are included in Section VI(C) below.

In addition to making critical points about the Companies' DSM screening methodology, KDOE wishes to make constructive suggestions. Rather than starting with an inconsistently defined list of individual demand-side technologies, supply technologies, program concepts, ideas for tariffs, and collections of technologies, the Companies' DSM program team might instead start by examining a number of major energy-using functions such as space cooling, lighting, shaft power, etc. They could use information sources such as E Source to obtain performance data about the most efficient technologies and design methods currently on the

[18] 1999 IRP, Volume III, Section IV, Exhibit DSM-2.

market within each functional area. The team might then outline DSM program ideas and strategies that could address the market barriers in each area that are preventing customers from adopting the most efficient available technologies and methods. If the Companies were to consider and analyze combinations of complementary technologies through a whole-system perspective, such an approach would mirror that taken by E Source in its *Technology Atlas* series and other publications. The primary criteria for narrowing down the options to a manageable number would be (a) the TRC test, (b) the size of the potential impact within the Companies' service area, and (c) the objective of developing a set of DSM "programs which are available, affordable, and useful to all customers" [Reference KRS 278.285 (1)(g)].

If the benefit/cost ratio on the TRC test had been used as the primary criterion for screening DSM alternatives, KDOE believes that the Direct Load Control and Standby Generation measures that were selected in the 1999 IRP would remain high priorities on the list of programs to be implemented. As shown in Exhibit DSM-5, most of these alternatives have a TRC benefit/cost ratio of well over 2. KDOE therefore supports the inclusion of these DSM programs in the Companies' IRP.

The Companies' analysis shows the TRC ratios of most of the High-Efficiency Lighting program elements to be between 1 and 2. This indicates to KDOE that other DSM alternatives may be preferable. Such alternative DSM programs may not have been included in the "long list," or may have been screened out through a flawed screening methodology. We suggest that rather than acting immediately to implement the High-Efficiency Lighting program, the Companies conduct additional investigations into DSM and market transformation program options, some of which will be described in the following section.

VI. MARKET TRANSFORMATION PROGRAM OPTIONS

In this section, we will suggest an alternative approach to meeting customers' needs for energy services that the Companies may wish to consider. KDOE believes that this approach will offer significant profitable long-term opportunities for the Companies and their shareholders as well as tangible economic benefits for their customers.

It has long been a truism that customers do not need or desire energy or electricity per se, but rather the services – warmth, light, hot water, cooling, drive power – that it provides for them. An economically rational customer will seek to maximize the net value of energy services purchased (i.e., the value added by the energy services minus the energy bill). An energy company that helps its customers maximize this value should enjoy a large market demand for its services.

Is it realistic to think that a company that sells a commodity can change its approach to one of helping its customers maximize value, even when it might result in less of the commodity being sold? The book *Natural Capitalism*, by Paul Hawken, Amory Lovins, and Hunter Lovins, describes several companies that are making the transition. Carrier, the world's largest manufacturer of air conditioning equipment, is now offering a "comfort lease" that ensures a certain indoor temperature during hot weather. Carrier can choose from a range of means to deliver the comfort: by doing lighting retrofits, installing high-performance windows, or installing its air conditioning equipment. "The less equipment Carrier has to install to deliver comfort, the more money Carrier makes. If Carrier retrofits a building so it no longer needs a lot, or even any, of its air conditioning capacity, Carrier can remove those modules and reinstall them elsewhere."[19]

[19] Hawken et al., *Natural Capitalism*, Rocky Mountain Institute, Snowmass, Colorado, 1999, p.135.

The same concept is prevalent overseas:

"Ten million buildings in metropolitan France have long been heated by *chauffagistes*; in 1995, 160 firms in this business employed 28,000 professionals. Rather than selling raw energy in the form of oil, gas, or electricity – none of which is what the customer really wants, namely warmth – these firms contract to keep a client's floorspace within a certain temperature range during certain hours at a certain cost. The rate is normally set to be somewhat below that of traditional heating methods like oil furnaces; *how* it's achieved is the contractors' business. They can convert your furnace to gas, make your heating system more efficient, or even insulate your building. They're paid for results – warmth – not for how they do it or how much of what inputs they use to do it. The less energy and materials they use – the more efficient they are – the more money they make. Competition between *chauffagistes* pushes down the market price of that "warmth service." Some major utilities, chiefly in Europe, provide heating on a similar basis, and some, like Sweden's Goteborg Energi, have recently made it the centerpiece of their growth strategy."[20]

Other examples:

- "Some utilities and third parties have been offering "torque services" that turn the shafts of your factory or pumping station for a set fee; the more efficiently they do so, the more they can earn."[21]

- Dow Chemical has started moving toward providing "dissolving services" rather than merely leasing solvents; their German affiliate plans to charge by the square centimeter degreased instead of by the amount of solvent used, thereby providing an incentive for its technicians to use less solvent rather than more. (Even better would be to use environmentally safer or no solvents.)

- Ciba's Pigment Division is moving to provide "color services" rather than merely selling dyes and pigments.

- Cookson in England leases the insulating service of refractory liners for steel furnaces.

- Pitney Bowes handles your firm's mail instead of just leasing postal meters.

- Interface in Atlanta leases floor-covering services rather than selling carpet. Interface is responsible for keeping it clean and fresh, replaces parts of it when indicated by monthly inspections, and reduces overall life-cycle costs. Interface has also developed a new polymeric floor covering material, called Solenium, that combines many of the performance advantages of carpet and hard flooring and can replace carpet altogether.[22]

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[20] *Ibid.*
[21] *Ibid.*, p.136.
[22] *Ibid.*, pp. 137-141.

In each case, the firms providing the service may sell somewhat less of their commodity or product, but are able to meet the customer's actual needs in a more efficient way. They are paid for results – providing value to the customer – rather than for the quantity of inputs. The incentives of the service provider and the customer are no longer at odds; both parties are interested in performing the needed function in the most efficient way possible. This concept may represent a cutting-edge trend in our economy.

If the Companies were to focus their activities more directly on becoming a provider of cost-effective energy services, they would initiate a number of programs and actions aimed at optimizing overall efficiency throughout the energy sector. Some of these initiatives would have immediate profit potential, while others would help transform energy markets so that customers would value more highly, and demand, the kinds of services the Companies could provide. The longer-term initiatives would also help establish the Companies' image in the market as consistently efficiency-oriented and dedicated to providing maximum value to their customers.

In the following section, we suggest a number of initiatives that we believe should be investigated for possible implementation.

A) Initiate a Comprehensive Market Transformation Program in the New Commercial Construction Sector

To overcome the litany of chronic market barriers to energy-efficient new construction outlined in Section IV above, a multi-pronged approach is advisable. The magnitude of the potential savings can be estimated by performing a technical potential study or by comparing the efficiency of typical new buildings being constructed today with state-of-the-art buildings in other jurisdictions. An excellent way to start the analysis of the technical potential would be to study the E Source Technology Atlas Series, which includes the following titles: *Commercial*

Space Cooling and Air Handling; *Lighting*; *Drivepower*; *Space Heating*; and *Residential Appliances*. A key theme found over and over throughout these highly detailed, thoroughly-documented works is that there are major efficiencies to be gained through the whole-system integration of properly-sized technologies. Initial costs can frequently be held constant or even reduced through careful, whole-system design. KDOE's information requests relating to the amount of new construction occurring in the Companies' service area were intended to see if the utility had made any preliminary estimates of the size of the technical potential for efficiency improvements in the buildings sector.[23]

Indirect but very real economic benefits resulting from improved daylighting designs such as increased retail sales[24] or improvement in the performance of students or workers[25,26] can make TRC benefit/cost ratios extremely high. For example, while the energy savings generated by the daylight-oriented whole-building design of Lockheed's 600,000 square foot office building in Sunnyvale, California paid back the initial extra costs in four years, absenteeism among a known population of workers dropped by 15%, which represents annual cost savings equal to the entire incremental cost of the improved design. To this could be added productivity gains estimated at another 15%, bringing the simple payback period down to a matter of weeks.[27]

There are several ways the Companies could enter the market for energy-efficient design services. One way would be to establish a (non-regulated) architectural/design firm, or form a

[23] Companies' responses to KDOE Information Requests #1-4 and #1-5.
[24] Heschong Mahone Group, "Skylighting and Retail Sales," submitted to Pacific Gas and Electric Company on behalf of the California Board for Energy Efficiency Third Party Program, 1999.
[25] Romm, Joseph J. and William D. Browning, "Greening the Building and the Bottom Line: Increasing Productivity Through Energy-Efficient Design," Rocky Mountain Institute, Boulder, Colorado, 1994, p. 11.
[26] Heschong Mahone Group, "Daylighting in Schools: An Investigation into the Relationship Between Daylighting and Human Performance," submitted to Pacific Gas and Electric Company on behalf of the California Board for Energy Efficiency Third Party Program, 1999.
[27] Romm and Browning, op. cit., pp. 8-9.

high-performance end. The company could help promote the use of energy lease agreements to reduce the problem of split incentives between commercial landlords and tenants.[30]

Another way to impact the low-efficiency end of the market would be to invert the hookup fee policy that is now in effect so that energy-efficient new buildings would be charged a low fee, or even would receive a rebate for hooking up to the grid, while energy sieves would be charged a much higher fee to cover some of the additional costs of distributing power to an inefficient building over its lifetime. If the fee differential were set high enough, such a policy would affect a building's initial costs, which would get the immediate attention of a segment of the market that might not otherwise respond to information about energy efficiency.

B) Use Local Integrated Resource Planning (LIRP)

Although several states have restructured their electric industries to encourage retail choice, the distribution system has remained a regulated monopoly. The method of local integrated resource planning, as described in a 1995 strategic issues paper by E Source, is designed to determine if costs could be reduced by deferring transmission and distribution upgrades through the use of geographically-focused demand-side programs.[31]
The E Source paper provides case studies illustrating how a number of utilities have used LIRP to forestall costly T&D upgrades. Targeted projects identified through the use of LIRP demonstrate its value both in rural areas with widely dispersed customers and in congested urban centers.

In 1993, Ontario Hydro planners were facing rapidly-growing demand in the congested Collingwood area and projected a T&D upgrade costing C$83 million. After conducting a LIRP analysis, they developed a strategy that combined load-shifting residential water heaters,

[30] Alliance to Save Energy, "Guidelines for Energy Efficient Commercial Leasing Practices," Washington, DC, 1992.

improving lighting efficiency, scheduling the operation of industrial furnaces, and making much smaller T&D upgrades, for a total cost of C$24.3 million, which included the cost of analyzing and administering the alternative strategy. Similar results were obtained in numerous other locations. Overall, Ontario Hydro credits LIRP with deferring some C$1.7 billion in T&D investments through September, 1995. LIRP has become the standard method of planning customer service and T&D planning. In the words of one distribution planner, "LIRP has become our business."[32]

The New York State Electric and Gas Corporation was able to avoid a $6.5 million T&D upgrade by providing an interruptible service rate to one large user and contracting to dispatch the user's two 300-kW backup generators, all at a hardware cost of $45,000.[33]

The E Source Strategic Issues paper concludes with a summary of advantages utilities can obtain by making use of the LIRP approach. The following benefits, which are reprinted from the report, would apply whether or not the utility industry is ever restructured in Kentucky:

- *"Improves utilization of existing T&D system assets while increasing grid reliability,* leading to lower costs per unit of electricity delivered, and deferred or avoided capital expenditures.

- *"Expands knowledge of the true cost of supplying electricity to a particular area at a specific time.* This information would be vital should a utility wheel power from another supplier to a retail customer. Such information can also be used by internal business units.

- *"Provides risk insurance during power sector restructuring.* With the future structure of the electricity industry uncertain, deferring capital expenditures makes additional economic sense from a risk reduction perspective. No one can predict who will own the grid in the future, or what compensation might be provided should ownership change.

- *"Reduces the need to obtain regulatory and public approval for potentially contentious T&D projects.* By reducing the need for new and upgraded powerlines and other T&D hardware, utilities clearly benefit in the public relations arena.

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[31] E Source, "Local Integrated Resource Planning: A New Tool for a Competitive Era," Boulder, Colorado, 1995.
[32] E Source, 1995, pp. 6-8.
[33] Ibid., p.10.

- *"Avoids long-term commitments to one-time, high-cost, supply-side options by investing in more flexible and modular technologies.* Incrementally adding capacity is likely to ensure that capital investment accurately reflects the needed demand rather than potentially overinvesting in a supply-side option---a particular concern for utilities that are experiencing slow growth in demand or that now service demand that might disappear.

- *"Provides experience with additional modular technologies whose costs are falling as production scales up.* Examples include advanced gas turbines, fuel cells, photovoltaics, chemical-battery storage, and flywheels.

- *"Provides customers with higher-quality service.* This should occur since the LIRP process is driven by the customer's concerns and needs. In fact, the LIRP approach could be used in determining the needs of individual customers, a key marketing foundation that could aid customer retention in the future.

- *"Maintains profitable load.* Once a utility looks closely at customer uses, it may discover a potential loss of load to competing fuels. Upon such a finding, the utility can develop a load retention program, as appropriate. LIRP may also reveal that some loads are not economic to serve and thus are good candidates for fuel switching or other measures.

- *"Assists a utility in getting various department plans in sync with each other.* Once a utility starts using LIRP as the start of its planning process, the utility can produce marketing, customer service, and sales plans that are more consistent with its distribution plans. This also increases the likelihood of producing a coordinated interface and a consistent relationship with customers.

- *"Leads to better utilization of generating assets.* Peak clipping options (storage and generation) would result in higher utilization of baseload generators. Smaller generating units also can lead to smaller reserve capacity requirements, and distributed generation can cut grid losses."[34]

C) Promote Cogeneration and Other Distributed Generation

Presently, the Companies neither actively encourage nor discourage cogeneration.[35] Central power plants are on the order of 33% efficient, with the remaining two-thirds or so of the fuel energy converted to waste heat. As noted by Thomas Casten of Trigen Energy Corporation, however, combined heat and power systems can make beneficial use of approximately 90% of

[34] Ibid., pp. 22-23.
[35] Companies' response to KDOE's information request #2-5.

the energy content of the fuel.[36] A firm seeking to optimize the efficiency of the energy sector as a whole would develop programs to enable customers with sizeable thermal loads to put this vast amount of wasted energy to use, and would develop shared savings arrangements to enable both parties to benefit from the increase in system efficiency.

Some analysts believe that the electric industry of the future will make much greater use of small-scale, distributed generation units, and that such a trend would fit well with the needs of a more competitive industry.[37] Distributed resources "could be applied at or near customer sites to manage multiple energy needs and to meet increasingly rigorous requirements for power quality and reliability. Distributed generators could also be deployed at utility sites – for example, at substations for transmission and distribution grid support. Some experts predict that 20% or more of all

new generating capacity built in the United States over the next 10 to 12 years could be for distributed applications..."[38]

In an effort to promote cost-effective distributed generation and renewable energy technologies, approximately thirty states have instituted "net metering."[39] Net metering laws (enacted by legislatures) or orders (instituted by public utility commissions) require electric utilities to purchase excess power from small-scale, renewable sources at the same retail rate they charge those customers. In effect, the owner of a small photovoltaic system can "run the meter backwards" when the system is producing more power than needed. Net metering policies usually set an upper limit on the size of the systems that are covered, and usually prohibit the

[36] Casten, Thomas R. and Mark C. Hall, "Barriers to Deploying More Efficient Electrical Generation and Combined Heat and Power Plants," Trigen Energy Corp., revised March, 2000, Section 2.2.
[37] Moore, Taylor, "Emerging Markets for Distributed Resources," *EPRI Journal*, March/April, 1998, pp. 8-17.
[38] *Ibid.*, pp. 9-10.
[39] Starrs, Thomas J., "Summary of State Net Metering Programs (Current)," updated September, 1999.

utility from erecting other barriers such as unreasonably burdensome interconnect and safety requirements.

Net metering would make small-scale distributed generation by customers more economically feasible. Because power is generated on-site, distributed generation would reduce transmission and distribution losses and improve the efficiency of the electricity grid. Certain renewable energy technologies such as photovoltaics can reduce costs system-wide by producing at their peak output on hot, sunny, summer days when the system may be facing its peak annual load.

It should be noted that the Companies included a net metering pilot program in their Letter Agreement of 7/28/99, which indicates to KDOE that they have no objection in principle to the concept.

The Rocky Mountain Institute has performed detailed research on the question of the value of distributed generation to utility companies. They conclude that "Properly counting approximately 75 documented and measurable diseconomies of scale, not just the few well-known economies of scale, will typically make decentralized ways to make, store, or save electricity around ten times more valuable than conventionally scale-blind comparisons had long shown."[40] If their analysis is even close to correct, it suggests that the Companies may be able to garner substantial economic benefits from distributed generation technologies that are now being overlooked because of outmoded analytical methods.

D) Support Statewide and Regional Market Transformation Initiatives

[40] Rocky Mountain Institute, "Scale in Power Systems," 1999, www.naturalcapitalism.org/sitepages/pid27.asp

The term "market transformation" refers to a set of planned interventions in the market that lead to longer-lasting impacts than traditional utility-sponsored DSM programs that depend on ongoing rebates for their effectiveness.[41,42]

Although some market transformation initiatives may not offer as much potential for short-term profit as some of the other measures discussed above, the participation of the Companies in market transformation activities could help the company establish their image in the market as experts in energy efficiency, and as being dedicated to maximizing the value that customers receive from the energy they purchase.

Regional market transformation alliances have been established in California, the Northwest, the Northeast, and the Midwest. Efforts typically involve a wide range of participants, and may include utilities, energy users, manufacturers, vendors, engineers, architects, construction firms, developers, building code officials, building owner associations, real estate professionals, lending institutions, federal agencies such as the U.S. Department of Energy and U.S. Environmental Protection Agency, state energy offices, and other parties.[43]

Kentucky companies and other interested organizations would be eligible to join he Midwest Energy Efficiency Alliance (MEEA). The mission of MEEA is "to work as a regional network of organizations to develop, design and implement energy efficiency and renewable energy resources in the rapidly-changing Midwest energy markets. The goals are to increase public value, improve environmental quality, lower energy costs, and promote sustainable economic development."[44]

[41] Meyers, Edward M., Stephen M. Hastie, and Grace M. Hu, "Using Market Transformation to Achieve Energy Efficiency: The Next Steps," *Electricity Journal*, May, 1997, pp. 34-41.
[42] Hall, Nick and John Reed, "Market Transformation: Expectations vs. Reality," *Home Energy*, July/August, 1999, pp. 16-20.
[43] Meyers et al., op. cit., p. 40.
[44] Midwest Energy Efficiency Alliance web page, updated 2/23/00.

. The Northwest Energy Efficiency Alliance, founded in 1997, has already reduced regional demand by 16 MW through market transformation initiatives related to compact fluorescent light bulbs, residential clothes washers, and semiconductor manufacturing process improvements.[45] The California Board for Energy Efficiency administers a variety of market transformation programs, including increasing the use of performance contracting with energy service companies, work with lighting manufacturers and distributors to bring energy-efficient lighting products to the market, home duct system improvements, and design tools for commercial architects and engineers.[46] Northeast Energy Efficiency Partnerships, Inc., has started market transformation programs in diverse areas including residential appliances, energy codes, high-efficiency motors, and commercial lighting design.[47]

E) Launch a Kentucky Design Initiative

The foregoing discussion has emphasized the large potential efficiency gains that can be made through improved design of energy systems. RMI quotes the following example provided by senior mechanical engineer Eng Lock Lee:

> A typical colleague may specify nearly $3 million worth of heating, ventilating, and air-conditioning (HVAC) equipment every year – enough to raise a utility's summer peak load by a megawatt. Producing and delivering that extra megawatt conventionally requires the utility to invest several million dollars in infrastructure. If better engineering education were ultimately responsible for the equipment's being made 20-50 percent more efficient (a reasonably attainable and usually conservative goal), then over a 30-year engineering career, the utility would avoid about $6-15 million in present-valued investments *per brain*, without taking into account any of the savings in operating energy or pollution. This returns at least a hundred to a thousand times the extra cost of that better education. The savings would cost even less if good practitioners disseminated their improved practices through professional discourse, mentoring, or competition, so that educating just one engineer could influence many more."[48]

[45] Northwest Energy Efficiency Alliance, "Northwest Utilities to Invest $100 Million in Energy Efficiency through a Regional Alliance," press release, March 17, 2000.
[46] California Board for Energy Efficiency, "About the CBEE," web page updated 9/15/99.
[47] Northeast Energy Efficiency Partnerships Initiatives web page.
[48] Hawken et al., *Natural Capitalism.*, pp. 111-112.

A company dedicated to providing optimum value to the purchasers of its energy services should be keenly interested in improving the quality of energy system design and engineering. The design of better industrial processes is particularly important. A comprehensive market transformation strategy cannot afford to overlook this high-leverage activity, and could use strategies such as awards, seminars, scholarships, and on-the-job training to encourage better whole-system design.

VII. CONCLUSION

Sections III, IV and VI above were intended to illustrate some of the ways that KDOE believes energy efficiency can be enhanced significantly in every sector of the economy in the long term. Achieving these potential efficiency gains will involve numerous parties in addition to the utility company, and it will require the development of imaginative, market-oriented strategies over a sustained period of time. While the task is not wholly the responsibility of the utility, we believe it still has an important role to play. The benefits to customers, the Companies, and society as a whole will make intensified efforts in this area more than worthwhile.

The market transformation approach can be used regardless of which regulatory framework is in place in Kentucky. KDOE hopes that the Companies will seriously consider market-transforming initiatives such as those outlined above, and will work toward the development of a variety of ways to improve end-use efficiency within Kentucky's energy sector while at the same time expanding their opportunities to earn financial returns for their shareholders.

VERIFICATION

I, Geoffrey M. Young, state that I have written the above document and that to the best of my knowledge and belief all statements and allegations contained therein are true and correct.

Geoffrey M. Young

Geoffrey M. Young, Assistant Director
Division of Energy
Department for Natural Resources

Subscribed and sworn to before me by Geoffrey M. Young, this the 5th day of June, 2000.

Jennie Lee Rutledge

NOTARY PUBLIC

My Commission Expires: Dec. 2, 01.

Respectfully submitted,

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COUNSEL FOR NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that on the 5th day of June, 2000 a true and accurate copy of the foregoing KENTUCKY DIVISION OF ENERGY'S COMMENTS RELATED TO THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY was mailed, postage pre-paid, to the following:

Hon. Douglas Brooks
Senior Counsel Specialist
Louisville Gas and Electric Company
220 W. Main Street
P.O. Box 32010
Louisville, Kentucky 40232-2010

Hon. Elizabeth E. Blackford
Office of Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601

Hon. David F. Boehm
Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

Mr. Walter F. Bell
Executive Director
Louisville Resource Conservation Council
P.O. Box 4174
Louisville, Kentucky 40204-0174

Iris Skidmore

RECEIVED
JUN - 5 2000
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	Case No. 99-430

ATTACHMENTS TO THE
COMMENTS OF THE ATTORNEY GENERAL

The attachments referenced in the Comments of the Attorney General filed earlier today were inadvertently omitted, and are submitted herewith.

Respectfully Submitted
/s/ Blackford
Elizabeth E. Blackford
Assistant Attorney General

NOTICE OF FILING AND CERTIFICATE OF SERVICE

Notice is hereby given that this the 5th day of June, 2000, the original and ten copies of the Attachments to the Comments of the Attorney General have been filed with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky and certification is made that this same day the parties were served by mailing copies to the following:

HONORABLE DOUGLAS BROOKS
SENIOR COUNSEL SPECIALIST
LOUSIVILLE GAS & ELECTRIC COMPANY
P O BOX 32010
LOUISVILLE KY 40232-2010

JOHN STAPLETON
DIRECTOR OF ENERGY
NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION
663 TETON TRAIL
FRANKFORT B KY 40601

HONORABLE DAVID F BOEHM
HONORABLE MICHAEL L KURTZ
BOEHM KURTZ & LOWRY
2110 CBLD CENTER
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CINCINNATI OH 45202

MR WALTER F BELL
EXECUTIVE DIRECTOR CONSERVATION COUNCIL
P O BOX 4174
LOUISVILLE KY 40204 0174
LOUISVILLE RESOURCE

HONORABLE IRIS SKIDMORE
HONORABLE RONALD P MILLS
OFFICE OF LEGAL SERVICES
FIFTH FLOOR CAPITAL PLAZA TOWER
FRANKFORT KY 40601

/s/ Blackford

IPP Hydro - True Cost of Capacity

0% Capacity Factor - 60% Excess capacity at no cost
Value of excess power
60% x 8760 hours = 5256 hours x $0.0165 /kwh = $86.72 /kw-yr

True cost at 0% Capacity Factor = $134 /kw-yr - $86.72 /kw-yr = $ 47.28 /kw-yr

10% Capacity Factor - 50% Excess capacity at no cost
Value of excess power
50% x 8760 hours = 4380 hours x $0.0165 /kwh = $72.27 /kw-yr

True cost at 10% Capacity Factor = $134 /kw-yr - $72.27 /kw-yr = $ 61.73 /kw-yr

20% Capacity Factor - 40% Excess capacity at no cost
Value of excess power
40% x 8760 hours = 3504 hours x $0.0165 /kwh = $57.82 /kw-yr

True cost at 20% Capacity Factor = $134 /kw-yr - $57.82 /kw-yr = $ 76.18 /kw-yr

30% Capacity Factor - 30% Excess capacity at no cost
Value of excess power
30% x 8760 hours = 2628 hours x $0.0165 /kwh = $43.36 /kw-yr

True cost at 30% Capacity Factor = $134 /kw-yr - $43.36 /kw-yr = $ 90.64 /kw-yr

40% Capacity Factor - 20% Excess capacity at no cost
Value of excess power
20% x 8760 hours = 1752 hours x $0.0165 /kwh = $28.91 /kw-yr

True cost at 40% Capacity Factor = $134 /kw-yr - $28.91 /kw-yr = $ 105.09 /kw-yr

50% Capacity Factor - 10% Excess capacity at no cost
Value of excess power
10% x 8760 hours = 876 hours x $0.0165 /kwh = $14.45 /kw-yr

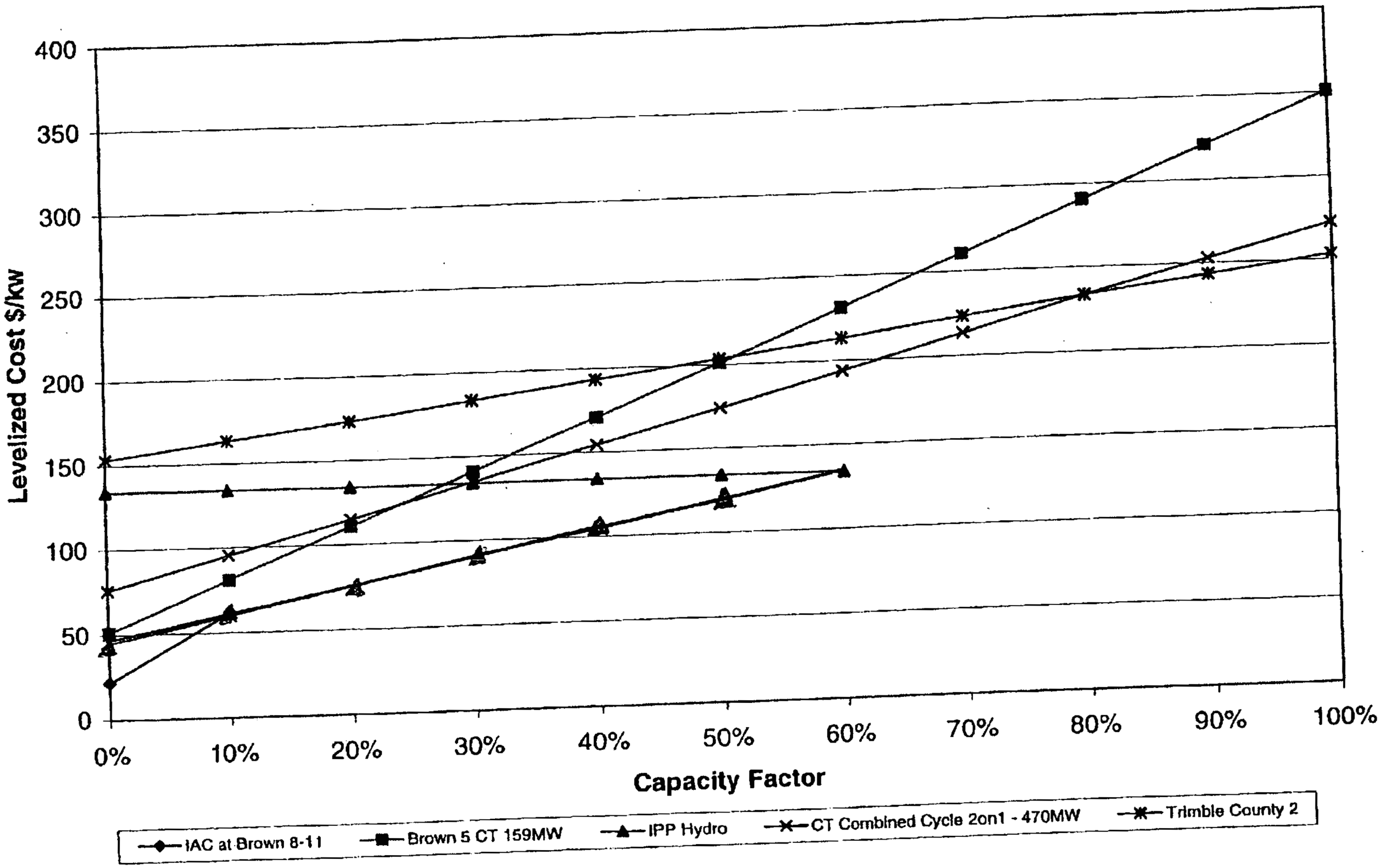
True cost at 50% Capacity Factor = $134 /kw-yr - $14.45 /kw-yr = $ 119.55 /kw-yr

60% Capacity Factor - 0% Excess capacity at no cost
Value of excess power
0% x 8760 hours = 0 hours x $0.0165 /kwh = $0.00 /kw-yr

True cost at 60% Capacity Factor = $134 /kw-yr - $0.00 /kw-yr = $ 134.00 /kw-yr

Least Costly Technologies

Base Capital, Base Heatrate, Base Fuel



Generation Systems Planning

1999 Screening.xls

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
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B. J. Helton
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

May 24, 2000

Mr. Douglas M. Brooks
Senior Counsel Specialist
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Assistant Attorney General
Division of Rate Intervention
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Frankfort, Kentucky 40602-2000

Ms. Iris P. Skidmore
Counsel for Natural Resources
And Environmental Protection
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Frankfort, Kentucky 40601

Mr. John Stapleton
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Mr. Michael L. Kurtz
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2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

Mr. Walter F. Bell
Executive Director
Louisville Resource Conservation
Council
P. O. Box 4174
Louisville, Kentucky 40204-0174

RE: Case No. 99-430, Louisville Gas and Electric Company and Kentucky Utilities Company

Dear Madams and Sirs:

Enclosed please find a memorandum that has been filed in the record of the above referenced case. Any comments regarding the contents of the memorandum should be submitted to the Commission within five days of receipt of this letter.

Sincerely,

Martin J. Huelsmann
Executive Director

Enclosure

EDUCATION PAYS

FILED

MAY 24 2000

PUBLIC SERVICE COMMISSION

INTRA-AGENCY MEMORANDUM

KENTUCKY PUBLIC SERVICE COMMISSION

TO: Case File No. 99-430

FROM: Jack Kaninberg JK

DATE: May 24, 2000

RE: Informal Conference of May 12, 2000
Regarding the LG&E and KU 1999
Integrated Resource Plan Filing

On May 12, 2000, an informal conference was held at the Commission's offices in Frankfort, Kentucky for the purpose of discussing issues related to the Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") 1999 Integrated Resource Plan ("IRP"). The parties represented at the conference were LG&E/KU, the Office of the Attorney General ("AG"), the Natural Resources and Environmental Protection Cabinet's Division of Energy ("NREPC") and the Commission Staff. A list of the attendees is attached to this memorandum.

NREPC began its remarks by noting its recent intervention in IRP cases within the past year. It suggested that LG&E/KU should consider using the Total Resource Cost ("TRC") test in all stages of the IRP process – including the final stage of integration – to minimize societal resource costs. When LG&E/LU responded that its use of the Present Value of Revenue Requirements ("PVRR") method is consistent with the PSC's certificate-of-need process, NREPC reiterated its position and suggested that perhaps the PSC should provide some guidance on that issue. Next, NREPC presented its perspective on DSM in the changing energy industry. NREPC wishes to promote flexible, market-oriented strategies that result in a functioning, competitive market for energy services, and it envisions a regulatory framework that facilitates market transactions. But the current reality from NREPC's perspective is far from this due to several factors, including a lack of information, split incentives, a lack of financing, perverse incentives, bureaucratic barriers, and environmental externalities. NREPC stated that studies show significant energy-savings potential in all customer classes, ranging from 30-70%. It expressed positive and negative opinions relative to the Companies' IRP. Among the latter were concerns about load shaping rather than promotion of energy savings throughout the year; concerns that the screening processes were biased against newer, more advantageous technologies; and concerns that packages of technologies should be considered as opposed to individual options. NREPC concluded its remarks by suggesting additional DSM programs that it believed to be profitable or worthwhile for the Companies in terms of image-building. Among these suggestions were new programs oriented toward new commercial construction, some of which could reduce peaks while not affecting off-peak periods; a study of the technical potential for energy efficiency in the Companies'service areas for comparisons to actual results and to guide program design; active promotion of cogeneration by the Companies; greater availability of financing; Local Integrated Resource Planning to minimize the cost of distribution services; reexamination of policies relative to hookup fees to encourage efficient construction; promotion of distributed generation, perhaps through net metering; promotion of expanded levels of energy-efficient manufactured housing; and support for stronger energy codes.

The AG addressed six areas of the Companies' IRP. The first was the status of three combustion turbines which have been planned for 2001, and LG&E/KU updated the current plans to purchase and install those units in a CT market characterized by scarce supply. The second area was the renovation plan for the Ohio Falls plant, and LG&E/KU indicated that preliminary engineering studies were done and relicensing efforts are progressing. The AG's third area of interest was the OVEC situation; that is, 250 MW of OVEC power may become available if a U.S. Enrichment Corporation facility is closed at Portsmouth, Ohio, and that capacity could postpone the need for new CTs. The fourth area was to recommend that the Companies consider for IRP purposes the cost implications and probability of greenhouse gas emissions reductions associated with the Kyoto protocol. The fifth area was to question whether the supply-side screening models used by the Companies are biased against renewable resources that have no variable fuel costs. The AG's final area of concern was to suggest that the Companies'preliminary screening of DSM options appears to cut off a significant set of options that fall slightly below a threshold numeric value of three. In response to that observation, LG&E/KU noted that its next DSM filing will be more far-reaching.

Commission Staff asked for additional information regarding two of the planned CTs. In response, LG&E/KU stated that the vendor for a planned CT at the Brown site would be ABB, while the vendor at the Paddy's Run site would be Siemens. The targeted in-service date for these units is June of 2001, and the Companies intend to soon file a certificate case. The Companies also indicated that LG&E's Trimble County site is being considered as a potential site for the installation of future CTs. Staff also requested clarification with regards to the narrowing of differences between KU's summer and winter peaks, and also with regards to KU's modeling for two wholesale customers.

In response to a request for a cost breakdown, the Companies indicated that this information could be filed within one week. The Informal Conference concluded with a brief discussion of the Companies' views with regards to the future markets for CTs and for new generation in the Midwest.

CASE NO. 99-430
LG&E – KU – INTEGRATED RESOURCE PLAN
INFORMAL CONFERENCE – MAY 12, 2000

NAME	WITH
1) JACK KANINBERG	PSC
2) RON WILLHITE	LG&E/KU
3) Ron Mills	NREPC, Legal Services
4) Geoffrey Young	Ky. Div. of Energy
5) Lonnie Bellar	LG&E/KU
6) Betty Blackford	OAG
7) David Brown Kinloch	OAG
8) Jeff Shaw	PSC - FIN. ANALYSIS
9) Scott Cooke	LGE/KU
10) CARYL M. PFEIFFER	KU/LG&E
11) Robert M. Conroy	KU/LG&E
12) John M. Stapleton	Ky. DIV. OF ENERGY
13) Bruce Sauer	KU/LG&E
14) Douglas Brooks	KU/LGE
15) Douglas Leichty	KU/LGE

LG&E ENERGY

LG&E Energy Corp.
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232

RECEIVED
MAY 22 2000
PSC
FINANCIAL ANALYSIS

May 19, 2000

Mr. Jeff Shaw
Division of Financial Analysis
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40602

RE: CASE NO. 99-430
The Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company

Dear Mr. Shaw:

Enclosed is the detailed cost breakdown of the 1.65 cents/kWh pursuant to your request at the May 12, 2000 Informal Conference.

Sincerely,

Ronald L. Willhite

Ronald L. Willhite
Director
Regulatory Affairs

Enclosure

cc: Jack Kaninburg, Public Service Commission of Kentucky
Elizabeth E. Blackford, Assistant Attorney General
Michael L. Kurtz, Boehm, Kurtz, and Lowery
Iris Skidmore, Counsel for Natural Resources and Environmental Protection Cabinet
Walter F. Bell, Louisville Resource Conservation Council

LG&E / KU Joint IRP, Case No. 99-430

Volume I, Table 8.3(b)12(g), Page 8-75
1998 Total Electricity Production Costs
Detailed Cost Breakdown

	Expense	MWH	$/MWH	Cents/kWh
Fuel	365,337,017		11.44	1.14
Total Labor	80,507,061		2.52	0.25
Variable Expenses	16,982,090		0.53	0.05
Other NonLabor	64,898,656		2.03	0.20
	527,724,823	31,934,212	16.53	$\boxed{1.65}$

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

JUN - 5 2000

PUBLIC SERVICE
COMMISSION

IN RE THE MATTER OF:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	)	Case No. 99-430

COMMENTS OF THE ATTORNEY GENERAL

In November 1999, the Louisville Gas & Electric Co. and Kentucky Utilities Co. (LG&E/KU) filed a joint 1999 Integrated Resource Plan (IRP), which covered its future plans for providing electric service to customers in Kentucky. The integrated plan included a load forecast and the company's plans for both supply and demand side resources to meet projected future needs. The plan also looked at other issues including environmental compliance. The Office of Attorney General of the Commonwealth of Kentucky has reviewed these plans and offers the following comments.

In general, the IRP provides a reasonably comprehensive roadmap of how the future needs of customers will be met. However, certain areas require the special attention of both LG&E/KU and the Commission to ensure that future customer needs are satisfied at the lowest possible cost to customers in Kentucky.

The LG&E/KU system has grown to the point that additional generating capacity will need to be secured in the near future if load growth continues as it has on these two systems in the last few years. The IRP calls for the addition of eleven 160 MW simple cycle combustion turbines (1760 MW) over the next ten years, and three Demand Side Management programs which combine for almost 219 MW. The plan also calls for a 480 MW combined cycle plant after 2010. All supply side additions rely primarily on natural gas. All proposed capacity additions through 2010 are primarily to meet peak loads.

While the LG&E/KU capacity expansion plan will meet customers' future demand, there may be lower cost ways of meeting these needs that LG&E/KU has failed to consider or has rejected due to problems with the models used. In addition, the IRP fails to include the very real possibility of future environmental regulation, especially with respect to global climate change.

One of the best and lowest cost options that may become available to LG&E/KU is its 9.5% ownership of Ohio Valley Electric Corporation (OVEC) capacity. OVEC owns 2300 MW of low cost generating capacity that supplies electricity to the U.S. Enrichment Corporation's Portsmouth Gaseous Diffusion Plant. Because of financial problems associated with enriching uranium at the two remaining plants in the United States, it is possible that one of the U.S. enrichment plants may be closed. Under agreement, neither plant can be closed until 2005 unless the Enrichment Corporation's financial condition significantly deteriorates. That significant financial deterioration has taken place in recent months. Whether a closure takes place in 2005 or before is unclear, but it seems likely that one the remaining plants will be closed, barring a bailout from Congress.

If the plant closed is the Portsmouth facility, the OVEC capacity could become available to the participating utilities. LG&E/KU companies own 9.5% of OVEC or 218 MW. Should this capacity become available, LG&E/KU could use this capacity to replace one of the proposed combustion turbines and part of a second unit. LG&E/KU did not include this possibility in the IRP as a way to meet future capacity needs. LG&E/KU should begin now to explore how existing contracts can be used or modified to assure that this low cost OVEC capacity it is entitled to will be used by LG&E/KU customers, if the Portsmouth plant is closed.

The IRP did an inadequate job of including the impact of pending environmental regulations, including Global Climate Change. LG&E/KU did some screening of supply side options with a CO2 tax addition, but no environmental costs beyond current regulations were included in the final IRP planning. Unless these environmental issues are included in planning, future capacity additions might exacerbate environmental problems rather than correcting them, causing unnecessarily higher rates for customers for many years into the future. A prime example is global climate change.

The Clinton Administration has signed the Kyoto Protocol, which calls for a 7% reduction in Carbon Dioxide (CO2) below 1990 levels by 2010. The IRP shows that LG&E/KU will substantially miss meeting this reduction. LG&E/KU's CO2 emissions were 25 million tons in 1990. The IRP projects coal and natural gas use to increase over the next 10 years and carbon emissions to grow to over 36 million tons, a 45% increase over 1990 emissions. If limits on carbon emissions are required in the United States, as have been done in some European countries, LG&E/KU will have a very difficult time reducing CO2 emissions to or below1990 emissions levels.

The economic consequences of failing to include the risk of future CO2 mandatory reductions is significant. Using a $50 per ton tax figure (which LG&E used in screening tests), LG&E/KU would have to pay over a half a BILLION dollar annual penalty for just the emissions over 1990 levels. If such a Carbon tax was imposed on all carbon emissions, LG&E/KU would have to pay $1.8 BILLION a year. Even if LG&E/KU considers the risk of such a tax to be low, the potential liability is so high that it should not be ignored in the IRP. At a minimum, LG&E/KU should run an additional optimal scenario with a carbon tax and weigh this scenario with the regular scenario, to determine the additional cost, if any, of pursuing capacity additions with low or no carbon emissions.

The two primary capacity options that have no associated carbon emissions are Demand Side Management (DSM) and renewable resources. The IRP includes 219 MW of DSM in the next five years, but only 46 MW of this DSM capacity actually reduces load and thus carbon emissions. While LG&E/KU is to be commended for pursuing this cost effective DSM, there is potential additional cost effective DSM which was screened out of consideration by the extremely subjective screening process used. The screening process assigned 82 DSM technologies ratings in four areas. Only those receiving a total score of 3 or better to received a complete evaluation.

Only 16 DSM technologies cleared this arbitrary threshold and received a full evaluation. There were 29 technologies that just barely missed the arbitrary cut-off, with ratings between 2.7 and 2.9. For each of these rejected technologies, a change in one of the four subjective ratings or a slight change in the threshold, would have allowed them to qualify for a full evaluation.

Considering the large amount of DSM that was selected for immediate implementation by the optimization plan as cost effective, many more DSM technologies should receive a complete analysis to determine if they would be cost effective. LG&E/KU should specifically attempt to provide a full evaluation of DSM options that will reduce carbon dioxide emissions.

LG&E/KU can also reduce CO2 emissions by adding supply side options that use renewable fuel sources (except combustion of biomass). Unfortunately, the IRP's optimal plan includes no renewable resources. It is possible this situation results from biases built into the planning models used by LG&E/KU.

The IRP first screens its potential capacity options to eliminate the more expensive ones. This screening process charts cost versus capacity factors. For options which burn fuel, the cost increases as the capacity factor increases, as more fuel is burned. For renewable resources (except wood), there is no fuel cost, and thus the graph of these resources is flat, containing just the capital cost and fixed O&M cost which are the same at all capacity factors. But this is an inaccurate representation of these renewable resources, such as solar, hydro and wind.

Renewable resources which have no fuel costs are not operated on the same priority as facilities which have variable fuel costs. Instead, for renewable resources with no fuel costs, once the resources are up and running they can be run full out continuously, regardless of the capacity needs of the utility. Because it costs nothing to run the facilities full out, any excess power generated can be sold on the wholesale market, and the funds generated by those sales can be attributed to the reduction of the initial capital costs of the renewable resource unit.

different capacity factors. These figures are then graphed on a copy of Figure 8.(5)(c)-1, from page 8-116 of Volume I of the IRP, which as also attached to these comments. This graph has both the LG&E/KU costs of the IPP hydro, and the corrected costs, charted to demonstrate the problem with the LG&E/KU model. The same correction demonstrated in this example should be applied to all renewable resources (except the combustion of biomass) screened by LG&E/KU.

The revised IPP Hydro calculations may also demonstrate a problem with LG&E/KU's model to select the optimum plan. Once the correction is made to account for surplus energy at lower capacity factors, the IPP Hydro is LG&E/KU's lowest cost option at all capacity factors between 10% and 60%. At a 0% capacity factor, only the Inlet Air Cooling of the Brown 8-11 Combustion Turbines has a lower cost. Since this option is already under construction, it is really not an option that can be selected to meet future needs and is thus eliminated from LG&E/KU's choices. Without this option, the IPP Hydro is LG&E/KU's lowest cost option at all capacity factors between 0% and 60% (the top end for this option).

In LG&E/KU's IRP optimization model all resources selected in the final plan were either peaking or intermediate capacity options having a capacity factor below 60%. Yet the lowest cost option at all capacity factors between 0% and 60%, IPP Hydro, was not selected and included in the optimum plan. Clearly there must be an error in the optimization model, such as the one in the screening model, that has excluded LG&E/KU's lowest cost option from the final plan. When LG&E/KU files a case for a Certificate of Convenience and Necessity to add more combustion turbines, as it has stated it will do in the near future, the Commission needs to conduct a thorough examination as to why a lower cost option, IPP Hydro, is not being pursued instead. This is even more important considering that a renewable resource with no carbon dioxide, sulfur dioxide, or nitric oxides emissions, which could reduce LG&E/KU's future environmental liability, has been overlooked.

LG&E/KU has also overlooked another low cost renewable resource option. The Falls of the Ohio hydro plant was built in 1928 and has not undergone any major upgrades in the last 70 years. Since that time, output from this low cost clean plant has fallen. LG&E's 1993 IRP called for this plant to be rehabilitated (in fact the cover of the IRP contains photos of the Falls of the Ohio plant). The rehabilitation would have resulted in another 16 MW of clean energy. That work was never done. The combined companies continue to evaluate rehabilitation and possible expansion of the capacity at this plant. As a result, additional capacity from this plant, whether from rehabilitation or expansion, was not even considered or included as part of the IRP. This low cost option needs to be included in the IRP. As long as LG&E/KU drags its feet on this option, ratepayers will fail to receive the financial and environmental benefits of rehabilitation and expansion.

Hydropower is the most abundant and lowest cost renewable resource in the region, but it was not even screened in the IRP, except for the one IPP Hydro option. LG&E/KU has experience with hydro with its Falls of the Ohio, Dix Dam and Lock 7 plants, and should be aware of the benefits of this low cost clean resource. While most of the dams on the Ohio River are available for hydro development, and new technologies have dramatically reduced the cost of developing dams like those on the Ohio River, LG&E/KU failed to even screen this low cost renewable resource. Future IRP's should do a more comprehensive job of correctly modeling and including renewable resources.

Respectfully Submitted

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601
(502) 696-5458

NOTICE OF FILING AND CERTIFICATE OF SERVICE

Notice is hereby given that this the 5th day of June, 2000, the original and ten copies of the Comments of the Attorney General have been filed with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky and certification is made that this same day the parties were served by mailing copies to the following:

HONORABLE DOUGLAS BROOKS
SENIOR COUNSEL SPECIALIST
LOUSIVILLE GAS & ELECTRIC COMPANY
P O BOX 32010
LOUISVILLE KY 40232-2010

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DIRECTOR OF ENERGY
NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION
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HONORABLE DAVID F BOEHM
HONORABLE MICHAEL L KURTZ
BOEHM KURTZ & LOWRY
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MR WALTER F BELL
EXECUTIVE DIRECTOR CONSERVATION COUNCIL
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LOUISVILLE KY 40204 0174
LOUISVILLE RESOURCE

HONORABLE IRIS SKIDMORE
HONORABLE RONALD P MILLS
OFFICE OF LEGAL SERVICES
FIFTH FLOOR CAPITAL PLAZA TOWER
FRANKFORT KY 40601

LG&E ENERGY

LG&E Energy Corp.
220 West Main Street
P.O. Box 32030
Louisville, Kentucky 40232
502-627-3450
502-627-3367 FAX

April 17, 2000

RECEIVED

APR 17 2000

PUBLIC SERVICE
COMMISSION

Martin Huelsmann
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40602

Re: Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company; Case No. 99-430

Dear Mr. Huelsmann:

You will find enclosed for filing on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company, in the above-referenced case, an original and six (6) copies of the following:

1. Responses to the Supplementary Requests of the Commission dated March 22, 2000;
2. Responses to the Supplementary Requests of the Attorney General dated March 21, 2000; and,
3. Responses to Kentucky Division of Energy (DOE) Second Request for Information dated March 21, 2000.

A copy of this letter and the enclosed filing have been mailed to counsel of record.

Please contact the undersigned if you have any questions. Thank you for your courtesies in this matter.

Sincerely yours,

Douglas M. Brooks
Senior Counsel Specialist, Regulatory
(502) 627-2557

Enclosures

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

APR 17 2000

PUBLIC SERVICE
COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN	)	
OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 99-430
AND KENTUCKY UTILITIES COMPANY	)	

RESPONSE TO
COMMISSION'S
SUPPLEMENTAL REQUEST FOR INFORMATION
DATED MARCH 21, 2000

FILED: April 17, 2000

PSC#2-1

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Commission's
Supplemental Request for Information
Dated March 21, 2000

Question No. 1

Responding Witness: Lonnie E. Bellar

Q-1. Refer to the response to Item 2 of the Staff's initial information request. Identify the size of the units referred to in the response and the approximate date that the Companies expect to make their filing for a Certificate of Convenience and Necessity.

A-1. The summer capacity rating of the units will be 133 MW and 151 MW. The Companies expect to file a Certificate of Public Convenience and Necessity in the 2nd quarter 2000.

PSC#2-2

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Commission's
Supplemental Request for Information
Dated March 21, 2000

Question No. 2

Responding Witness: H. Bruce Sauer

Q-2. Refer to the response to Item 9 of the Staff's initial information request. Provide a more detailed description of the relationship between annual HDD, HDH at time of winter peak, and winter peak demand. Provide a similar description of the relationship between CDD, THI for the 24 hours preceding summer peak, and summer peak demand.

A-2. No relationship is expected between annual CDD and summer peak demand, because annual CDD is the total number of cooling degree days <u>accumulated for the whole year</u> while summer peak demand is the maximum <u>hourly</u> demand for summer of the year. By the same token, there is no relationship between annual HDD and winter peak demand. The mathematical description of the relationship between the THI variable and summer peak demand is presented in page 27 of Section E, Technical Appendix 1, Volume II. The same page also contains the equation for the relationship between the HDH variable and winter peak demand. Coefficients of the weather variables in the double-logarithmic equations imply that 1% change in the THI variable would increase summer peak demand by about 1.5% and 1% change in the HDH variable would result in approximately a 0.3% increase in winter peak demand.

PSC#2-3

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Commission's
Supplemental Request for Information
Dated March 21, 2000

Question No. 3

Responding Witness: H. Bruce Sauer

Q-3. Refer to the response to Item 14 of the Staff's initial information request. Identify industrial uses on either of the Companies' systems that are weather-sensitive and explain why a 70-degree base tests "more significant than a 65-degree base."

A-3. Industrial customers can have space cooling and heating and water heating usage just like any other customer. Typically, less industrial space is conditioned than in commercial or residential premises, and the total load devoted to these uses is significantly less. There also tends to be more heat gain in industrial facilities than in commercial or residential premises. Therefore the most important weather sensitive usage of industrial customers would be in space cooling or ventilation. Since overall cooling and ventilation load constitutes a smaller percentage of total load, weather conditions need to be more extreme in order to make a significant impact on load.

PSC#2-4

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Commission's
Supplemental Request for Information
Dated March 21, 2000

Question No. 4

Responding Witness: Lonnie E. Bellar

Q-4. Refer to the response to Item 18 of the Staff's initial information request. Identify the contingency conditions that might result in increased loading of the Companies' distribution systems and describe the specific benefits that can be derived from such practices.

A-4. Loading above 100% on power transformers should only occur during loss of capacity during high load periods. The most likely cause would be loss of a substation transformer. The benefits from this practice are the delay of capital expenditures that would be required in a redundant system. Allowing power transformers to load above nameplate in emergency situations allows us to provide reliable service to our customers for much less cost.

PSC#2-5

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Commission's
Supplemental Request for Information
Dated March 21, 2000

Question No. 5

Responding Witness: Lonnie E. Bellar

Q-5. Refer to the response to Item 24 of the Staff's initial information request, specifically, the reference to customers leaving the interruptible rate schedules. Given the increases and volatility in summer peak prices over the past two years, identify any modifications that have been considered to make these tariffs more attractive to large commercial and industrial customers.

A5. No specific modification to the existing tariffs have been developed. Additional programs that would both be beneficial to the customer as well as the Companies in reducing the summer peak demand, such as the standby generation program identified in the IRP, are being developed.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

APR 17 2000

PUBLIC SERVICE
COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN	)	
OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 99-430
AND KENTUCKY UTILITIES COMPANY	)	

RESPONSE TO
KENTUCKY DIVISION OF ENERGY'S
SECOND REQUEST FOR INFORMATION
DATED MARCH 21, 2000

FILED: April 17, 2000

DOE#2-1

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Kentucky Division of Energy's
Second Request for Information
Dated March 21, 2000

Question No. 1

Responding Witness: Gregory B. Fergason

Q-1. Please refer to the response to KDOE's question #7, 1st set. The first sentence reads, "Commercial Construction Building Standard (#61) was a consideration of commercial 'Efficient Construction'." What does that mean?

A-1. The Commercial Construction Building Standards (#61) is a program that promotes "Efficient Construction" for commercial customers.

DOE#2-2

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Kentucky Division of Energy's
Second Request for Information
Dated March 21, 2000

Question No. 2

Responding Witness: Gregory B. Fergason

Q-2. Please refer to KDOE's question #10, 1st set, which relates to the proportion of DSM items screened out.

a. How does screening out options help the Companies "learn more about the DSM technologies available"?

b. How did the Companies determine the number of alternatives that would be "manageable"?

c. In order to prioritize the DSM options, why didn't the Companies simply use a single criterion, namely, the estimated benefit/cost ratio using the TRC test?

A-2. a. Within the screening process, the Companies learn through the process of gathering information to make an informed decision on rating a technology for each criterion.

b. No specific number of alternatives was set as "manageable".

c. The qualitative screening process allows the Companies to screen out cost ineffective programs and devote more time to designing cost effective programs. In the final integrated analysis the Companies did use one criterion, lowest revenue requirement.

DOE#2-3

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Kentucky Division of Energy's
Second Request for Information
Dated March 21, 2000

Question No. 3

Responding Witness: Gregory B. Fergason

Q-3. The response to KDOE's question #11, 1st set, restates information that was included in the IRP, but does not, in our view, answer the question. Did the Companies consider the possibility that some of the items in the long list might not be ranked high when considered individually, but might be worthy of further consideration if included in a package along with other complementary items? Please explain the response.

A-3. No. Each technology was considered on its own merits in the screening process. If the Company looked at each possible combination of just 2 of the 82 technologies that would add 3,403 new combinations of technologies to evaluate which would defeat the purpose of screening the technologies. We did not attempt to group less cost effective programs with more cost effective programs, which would result in a higher overall revenue requirement.

DOE#2-4

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Kentucky Division of Energy's
Second Request for Information
Dated March 21, 2000

Question No. 4

Responding Witness: Gregory B. Fergason

Q-4. The first sentence of the response to KDOE's question #20, 1st set, states, "This exercise is not relevant to the development of the IRP, which is fundamentally designed to determine which options result in the lowest present value revenue requirements."

a. KDOE has been working under the assumption that in a regulated utility industry, the IRP should be fundamentally designed to determine which options result in the lowest present value of total resource costs (TRC). Isn't it true that the use of the present value revenue requirement (PVRR) as the final decision criterion substitutes the Utility Cost test for the TRC test?

b. It is intuitively obvious that DOE#1-20 is not relevant to the development of the IRP, since the IRP was developed before the question was asked. We believe that DOE#1-20 is relevant, however, to the question of whether the screening methodology used by the Companies is appropriate or not. One staff person at America Electric Power, spending a couple of hours, was able to run their proprietary computer program and provide a quantitative response to the same data request. Please reconsider your decision not to answer DOE#1-20.

A-4. a. The KDOE assumption is incorrect. Pursuant to 807 KAR 5:058, the Companies are required to provide a plan that meets the forecasted electricity requirements at the lowest cost while providing adequate and reliable supply of electricity. The Companies are required to provide the present value of revenue requirements which is the accepted method to developing optimal integrated resource plans. The Utility Cost test is an estimate of the revenue requirements of a utility, however, it is not a substitute for the TRC test.

b. We continue to see no relevance to the exercise for the same reasons.

DOE#2-5

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Kentucky Division of Energy's
Second Request for Information
Dated March 21, 2000

Question No. 5

Responding Witness: Lonnie E. Bellar

Q-5. Please refer to KDOE's question #29, 1st set. Does the response mean that the Companies neither actively encourage nor discourage cogeneration?

A-5. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

APR 17 2000

PUBLIC SERVICE
COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN	)	
OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 99-430
AND KENTUCKY UTILITIES COMPANY	)	

**RESPONSE TO
ATTORNEY GENERAL'S
SUPPLEMENTAL REQUEST FOR INFORMATION
DATED MARCH 21, 2000**

FILED: April 17, 2000

AG#2-1

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

RECEIVED

APR 17 2000

PUBLIC SERVICE
COMMISSION

CASE NO. 99-430

Response to
Attorney General's
Supplemental Request for Information
Dated March 21, 2000

Question No. 1

Responding Witness: Lonnie E. Bellar

Q-1. Follow-up to Item 15. Has any analysis been done to determine the reliability of older generating units, and whether these units will be able to meet future environmental regulations? If so, please provide the results of this analysis.

A-1. No specific analysis has been done on the reliability of older generating units. All generating units are included when determining environmental compliance strategies.

AG#2-2

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Attorney General's
Supplemental Request for Information
Dated March 21, 2000

Question No. 2

Responding Witness: Gregory B. Fergason

Q-2 Follow-up to Item 17. This response refers to analyzing DSM programs based on the real current cost of energy. Shouldn't the cost of DSM instead be compared to the projected future avoided costs of adding new generating capacity?

A-2. The original statement was from the customers' perspective. The lower the real cost of energy, the less beneficial DSM programs are to the customer. Each DSM program has to satisfy a customer or it will not be successful and therefore will not change the customers' demand for electricity.

AG#2-3

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Attorney General's
Supplemental Request for Information
Dated March 21, 2000

Question No. 3

Responding Witness: Lonnie E. Bellar

Q-3. Follow-up to Item 18. For each of the last 11 years, 1989-1999, please supply the following:

a. Total Kilowatt-hours generated to supply LG&E and KU's internal energy demand, including municipals.
b. Total Kilowatt-hours generated for sale of power off-system.
c. Total Kilowatt-hours generated by LG&E/KU generators (thus including off-system sales but excluding energy purchased to supply internal energy demand).

A-3.

a. Energy generated is measured at the output of the generating unit and is not differentiated between the type of the ultimate consumer. Only total energy produced are available from the generating units; therefore, historical kilowatt-hours include those associated with meeting internal demand and off-system sales.
b. See response to 3 a.
c. Total kilowatt-hours generated by LG&E/KU generators (including only LG&E's portion of Trimble County)

1989	22,725,224,000
1990	24,122,456,000
1991	26,024,291,000
1992	25,868,120,000
1993	27,475,032,000
1994	27,727,222,000
1995	27,677,814,000
1996	30,420,512,000
1997	29,884,726,000
1998	31,934,493,000
1999	32,659,537,000

AG#2-4

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Attorney General's
Supplemental Request for Information
Dated March 21, 2000

Question No. 4

Responding Witness: Lonnie E. Bellar

Q-4. Follow-up to PSC Item 19. With respect to the 1998 "Total Electricity Production Costs" of 1.65 cents per kilowatt-hour, does this represent the total average variable cost of producing electricity? If not, please explain in detail exactly what costs are included in this figure, and what costs are not included.

A-4. No, it includes all fixed and variable operating and maintenance costs.

AG#2-5

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Attorney General's
Supplemental Request for Information
Dated March 21, 2000

Question No. 5

Responding Witness: Caryl M. Pfeiffer

Q-5. Follow-up to PSC Item 25. For each of the last 11 years, 1989-1999, please supply the total SO2 (sulfur-dioxide) emissions from LG&E/KU generators (thus including off-system sales but excluding emissions associated with energy purchased to supply internal energy demand).

A-5. Historical SO2 emissions in tons (includes only LG&E's portion of Trimble County):

1989	228,060
1990	231,908
1991	214,690
1992	223,623
1993	232,786
1994	222,693
1995	155,747
1996	177,521
1997	188,969
1998	204,906
1999	205,348

AG#2-6

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Attorney General's
Supplemental Request for Information
Dated March 21, 2000

Question No. 6

Responding Witness: Lonnie E. Bellar

Q-6. Follow-up to PSC Item 25. For each of the years in the IRP planning period, through 2013, and based on the base plan in the IRP, please supply the total SO2 (sulfur-dioxide) emissions associated with supplying LG&E and KU's internal energy demand, including municipals.

A-6. Projected SO2 emissions in tons (includes only LG&E's portion of Trimble County):

2000	144,951
2001	145,402
2002	149,531
2003	140,924
2004	140,215
2005	144,217
2006	145,956
2007	150,425
2008	151,330
2009	154,574
2010	125,482
2011	128,555
2012	131,506
2013	131,909

AG#2-7

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 99-430

Response to
Attorney General's
Supplemental Request for Information
Dated March 21, 2000

Question No. 7

Responding Witness: Lonnie E. Bellar

Q-7. Follow-up to PSC-25. Please supply the following information with respect to SO2 allowances:

a. The current market value of SO2 allowances.

b. The projected future price of SO2 allowances, on a year by year basis for each year of the planning period, used in the Clean Air Act compliance analysis contained in the IRP.

A-7. a. The March 2000 SO_2 allowance price was $135/ton according to Cantor-Fitzgerald.

b. The base allowance price used in the Clean Air Act compliance analysis was $200/ton through 2003. After 2003 the price is escalated at 2% per year.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAR 21 2000

PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN)
OF LOUISVILLE GAS AND ELECTRIC COMPANY)
AND KENTUCKY UTILITIES COMPANY)

CASE NO. 99-430

KENTUCKY DIVISION OF ENERGY'S SECOND REQUEST FOR INFORMATION TO THE LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Comes the Natural Resources and Environmental Protection Cabinet, Division of Energy, Intervenor, herein, and makes the following request for information for the purpose of evaluating the effectiveness of the proposed joint integrated resource plan (IRP):

1. Please refer to the response to KDOE's question #7, 1st set. The first sentence reads, "Commercial Construction Building Standards (#61) was a consideration of commercial 'Efficient Construction'." What does that mean?

2. Please refer to KDOE's question #10, 1st set, which relates to the proportion of DSM items screened out.

   a. How does screening out options help the Companies "learn more about the DSM technologies available"?

   b. How did the Companies determine the number of alternatives that would be "manageable"?

c. In order to prioritize the DSM options, why didn't the Companies simply use a single criterion, namely, the estimated benefit/cost ratio using the TRC test?

3. The response to KDOE's question #11, 1st set, restates information that was included in the IRP, but does not, in our view, answer the question. Did the Companies consider the possibility that some of the items in the long list might not be ranked high when considered individually, but might be worthy of further consideration if included in a package along with other complementary items? Please explain the response.

4. The first sentence of the response to KDOE's question #20, 1st set, states, "This exercise is not relevant to the development of the IRP, which is fundamentally designed to determine which options result in the lowest present value revenue requirements."

a. KDOE has been working under the assumption that in a regulated utility industry, the IRP should be fundamentally designed to determine which options result in the lowest present value of total resource costs (TRC). Isn't it true that the use of the present value revenue requirement (PVRR) as the final decision criterion substitutes the Utility Cost test for the TRC test?

b. It is intuitively obvious that DOE#1-20 is not relevant to the development of the IRP, since the IRP was developed before the question was asked. We believe that DOE#1-20 is relevant, however, to the question of whether the screening methodology used by the Companies is appropriate or not. One staff person at America Electric Power, spending a couple of hours, was able to run their proprietary computer program and provide a quantitative response to the same data request. Please reconsider your decision not to answer DOE#1-20.

5. Please refer to KDOE's question #29, 1st set. Does the response mean that the Companies neither actively encourage nor discourage cogeneration?

Respectfully submitted,

IRIS SKIDMORE
RONALD P. MILLS
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601
Telephone: (502) 564-6676

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that on the 21 day of March, 2000 a true and accurate copy of the foregoing Kentucky Division Of Energy's Second Request For Information To The Louisville Gas And Electric Company And Kentucky Utilities Company was mailed, postage pre-paid, to the following:

Hon. Douglas Brooks
Senior Counsel Specialist
Louisville Gas and Electric Company
220 W. Main Street
P.O. Box 32010
Louisville, Kentucky 40232-2010

Hon. Elizabeth E. Blackford
Office of Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601

Hon. David F. Boehm
Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

Mr. Walter F. Bell
Executive Director
Louisville Resource Conservation Council
P. O. Box 4174
Louisville, Kentucky 40204-0174

Iris Skidmore

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAR 2 2 2000

PUBLIC SERVICE
COMMISSION

IN RE THE MATTER OF:

THE JOINT INTEGRATED RESOURCE	)	
PLAN OF LOUISVILLE GAS AND	)	Case No.
ELECTRIC COMPANY AND KENTUCKY	)	99-430
UTILITIES COMPANY	)	

THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUESTS FOR INFORMATION

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office for Rate Intervention, and submits these Requests for Information to Louisville Gas and Electric Company and Kentucky Utilities Company, Inc., to be answered in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the company witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please

identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Respectfully Submitted,

E. Blackford

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4815

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that the original and twelve copies of the foregoing were filed this the 21st day of Msrch, 2000, with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601, and certify that on this same date true copies were served on the parties by mailing same, postage prepaid to:

HONORABLE DOUGLAS BROOKS
SENIOR COUNSEL SPECIALIST
LOUSIVILLE GAS & ELECTRIC COMPANY
P O BOX 32010
LOUISVILLE KY 40232-2010

JOHN STAPLETON
DIRECTOR OF ENERGY
NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION
663 TETON TRAIL
FRANKFORT B KY 40601

HONORABLE DAVID F BOEHM
HONORABLE MICHAEL L KURTZ
BOEHM KURTZ & LOWRY
2110 CBLD CENTER
36 EAST SEVENTH STREET
CINCINNATI OH 45202

MR WALTER F BELL
EXECUTIVE DIRECTOR
LOUISVILLE RESOURCE CONSERVATION COUNCIL
P O BOX 4174
LOUISVILLE KY 40204 0174

HONORABLE IRIS SKIDMORE
HONORABLE RONALD P MILLS
OFFICE OF LEGAL SERVICES
FIFTH FLOOR CAPITAL PLAZA TOWER
FRANKFORT KY 40601

/s/ Blackford

THE ATTORNEY GENERAL'S REQUESTS FOR INFORMATION

1. Follow-up to Item 15. Has any analysis been done to determine the reliability of older generating units, and whether these units will be able to meet future environmental regulations? If so, please provide the results of this analysis.

2. Follow-up to Item 17. This response refers to analyzing DSM programs based on the real current cost of energy. Shouldn't the cost of DSM instead be compared to the projected future avoided costs of adding new generating capacity?

3. Follow-up to Item 18. For each of the last 11 years, 1989-1999, please supply the following:

a) Total Kilowatt-hours generated to supply LG&E and KU's internal energy demand, including municipals.

b) Total Kilowatt-hours generated for sale of power off-system.

c) Total Kilowatt-hours generated by LG&E/KU generators (thus including off-system sales but excluding energy purchased to supply internal energy demand).

4. Follow-up to PSC Item 19. With respect to the 1998 "Total Electricity Production Costs" of 1.65 cents per kilowatt-hour, does this

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
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FRANKFORT, KENTUCKY 40602-0615
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(502) 564-3940
Fax (502) 564-3460

B. J. Helton
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

CERTIFICATE OF SERVICE

RE: Case No. 99-430
Louisville Gas and Electric Company and Kentucky Utilities Company

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed copy of the Commission Staff's data request in the above case was served upon the following by U.S. Mail on March 22, 2000.

Parties:

Mr. Douglas M. Brooks
Counsel for LG&E Energy Corp.
Senior Counsel Specialist
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232

Ms. Elizabeth Blackford
Assistant Attorney General
Division of Rate Intervention
P.O Box 2000
Frankfort, Kentucky 40402-2000

Ms. Iris Skidmore
Counsel for Natural Resources
And Environmental Protection
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601

Mr. Michael Kurtz
Boehm, Kutrz and Lowry
2210 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

Mr. Walter Bell
Executive Director
Louisville Resource Conservation Council
P.O. Box 4174
Louisville, Kentucky 40204-0174

Mr. John Stapleton
Division of Energy
663 Teton Trail
Frankfort, Kentucky 40601

Stephanie J. Bell
Secretary of the Commission

Enclosure

EDUCATION PAYS

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW PURSUANT TO 807 KAR 5:058 OF THE JOINT 1999 INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY KENTUCKY UTILITIES COMPANY	))))	CASE NO. 99-430

COMMISSION STAFF'S SUPPLEMENTAL REQUEST FOR INFORMATION TO LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

The Commission Staff requests that Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies") file an original and 6 copies of the following information, with a copy to all parties of record, by no later than the due date set out in the procedural schedule previously established for this case. Each copy of the data requested should be placed in abound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 2(b), Sheet 1 of 3. Include with each response the name of the person responsible for responding to questions relating to the information provided. All responses filed with the Commission Staff should be delivered to the office of the Commission's Executive Director.

1. Refer to the response to Item 2 of the Staff's initial information request. Identify the size of the units referred to in the response and the approximate date that the Companies expect to make their filing for a Certificate of Convenience and Necessity.

2. Refer to the response to Item 9 of the Staff's initial information request. Provide a more detailed description of the relationship between annual HDD, HDH at time of winter peak, and winter peak demand. Provide a similar description of the relationship between CDD, THI for the 24 hours preceding summer peak, and summer peak demand.

3. Refer to the response to Item 14 of the Staff' initial information request. Identify industrial uses on either of the Companies' systems that are weather-sensitive and explain why a 70-degree base tests "more significant than a 65-degree base."

4. Refer to the response to Item 18 of the Staff's initial information request. Identify the contingency conditions that might result in increased loading of the Companies' distribution systems and describe the specific benefits that can be derived from such practices.

5. Refer to the response to Item 24 of the Staff's initial information request, specifically, the reference to customers leaving the interruptible rate schedules. Given the increases and volatility in summer peak prices over the past two years, identify any modifications that have been considered to make these tariffs more attractive to large commercial and industrial customers.

Respectfully submitted

Richard G. Raff

Richard G. Raff
Staff Attorney

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

COMMONWEALTH OF KENTUCKY
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B. J. Helton
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

March 6, 2000

Douglas M. Brooks, Esq.
Senior Counsel Specialist, Regulatory
Louisville Gas and Electric Company
220 West Main Street
P.O. Box 32010
Louisville, Kentucky, 40232

RE: Petition for Confidential Protection
99-430

Dear Mr. Brooks:

The Commission has received your petition filed February 23, 2000, to protect as confidential certain information in the companies' responses to the Commission's data requests in its January 25, 2000 order. A review of the information has determined that it is entitled to the protection requested on the grounds relied upon in the petition, and it will be withheld from public inspection.

If the information becomes publicly available or no longer warrants confidential treatment, you are required by 807 KAR 5:001, Section 7(9)(a) to inform the Commission so that the information may be placed in the public record.

Sincerely,

Martin J. Huelsmann
Executive Director

LG&E ENERGY

LG&E Energy Corp.
220 West Main Street
P.O. Box 32030
Louisville, Kentucky 40232
502-627-3450
502-627-3367 FAX

February 23, 2000

RECEIVED

FEB 23 2000

PUBLIC SERVICE COMMISSION

Martin Huelsmann
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40602

Re: Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company; Case No. 99-430

Dear Mr. Huelsmann:

You will find enclosed for filing on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company in the above-referenced case an original and six (6) copies of the following:

1. Responses to the First Request of the Commission dated January 25, 2000;
2. Responses to the First Request of the Attorney General dated January 25, 2000;
3. Responses to Kentucky Division of Energy (DOE) First Set of Interrogatories Dated January 18, 2000;
4. Petition for Confidential Protection.

A copy of this letter and the enclosed filing have been mailed to counsel of record.

Please contact the undersigned if you have any questions. Thank you for your courtesies in this matter.

Sincerely yours,

Douglas M. Brooks

Douglas M. Brooks
Senior Counsel Specialist, Regulatory
(502) 627-2557

DMB:bjl

Enclosures

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

FEB 23 2000

PUBLIC SERVICE
COMMISSION

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	**CASE NO. 99-430**

PETITION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR CONFIDENTIAL PROTECTION

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") petition the Public Service Commission ("Commission") pursuant to 807 KAR 5:001 Section 7 to grant confidential protection to certain information contained in the Companies' responses to the data requests of the Commission propounded in its Order dated January 25, 2000. In support of this Petition, LG&E and KU state as follows:

1. The Companies are filing contemporaneously with this Petition their responses to the data requests of the Commission propounded in its Order of January 25, 2000. The information for which confidential protection is requested relates to projected real prices of electricity by class for LG&E (Question 1a.), the average percentage increase in the nominal retail price of electricity for KU (Question 1b. and 5a.), the five and fifteen year average gas price growth rates (Question 1c.), and responses from CT manufacturers to an RFP issued by the Companies (Question 7b.). This information is all confidential and proprietary, the disclosure of which would (1) provide unfair commercial advantages to the Companies' competitors in the wholesale market for bulk and off-system power sales and (2) damage the Companies' abilities to obtain new CTs at the lowest

possible price. These harms would result in either less revenues or higher costs for the Companies to the detriment of their customers.

2. The Commission reviewed KU's last Integrated Resource Plan in Case No. 96-173, In the Matter of a Review Pursuant to 807 KAR 5:058 of the 1996 Integrated Resource Plan of Kentucky Utilities Company, and reviewed LG&E's last Integrated Resource Plan in Case No. 93-425, In the Matter of a Review Pursuant to 807 KAR 5:058 of the 1993 Integrated Resource Plan of Louisville Gas and Electric Company. Since then, the electric utility industry has undergone profound changes. The passage of the Energy Policy Act of 1992 has brought extensive competition to the electric wholesale market and introduced numerous new marketers, brokers, and clearinghouses, and many new sources of non-utility generation of power. The change in federal law has resulted in electric utilities filing nondiscriminatory open-access transmission tariffs and applications for approval of market-based wholesale power rates with the Federal Energy Regulatory Commission. The FERC has authorized utilities, including the Companies, to charge market-based prices for wholesale power transactions and approved open-access transmission services tariffs. See, e.g., Kentucky Utilities Company, 71 FERC Par. 61,250 (May 31, 1995). All of these regulatory developments and changes in the law have created a robust and competitive wholesale market for bulk and off-system power sales.

3. Under KRS 61.878(1)(c), commercial information, generally recognized as confidential, is protected if disclosure would cause competitive injury. The Companies' projections of average retail prices for 1999 through 2013, the gas price growth rate projections, and detailed discussion of forecast trends, constitute information that is generally recognized as confidential. This information must remain confidential if the Companies are to continue to be able to vigorously compete for wholesale sales and purchase wholesale sales at competitive prices. Disclosure would

permit competitors in the wholesale market to make reasonable estimates of the Companies' costs. This in turn would result in purchases of bulk and off-system sales at higher prices and the loss of, or reduced margins on, wholesale sales, and thus injury to both the Companies and their customers, and would give commercial advantages to the Companies' competitors. The responses to questions 1a., 1b., 1c. and 5a. contain the Companies' projected retail price of electricity and gas price growth rates for the period 1999 through 2013 and were developed internally by the Companies personnel. This information is not on file with the FERC, SEC or other public agency, is not available from any commercial or other source outside the Companies, and is limited in distribution within the Companies to those employees who have a business reason to have access to such information. Disclosure of this information would provide the Companies' competitors in the wholesale market with a significant amount of information regarding the Companies' future costs, and would also provide buyers of the Companies' off-system and bulk power a competitive advantage. This information would also allow buyers to create a bargaining position superior to the Companies' position, which would place the Companies at a competitive disadvantage.

4. Public disclosure of the bids received by CT manufacturers (Response to Question 7b.) would damage the Companies' ability to negotiate future contracts for the purchase of combustion turbines. This situation is much like the public disclosure of coal supply bid analyses, which the Commission has previously held to qualify for confidential protection. See, e.g., Order dated November 30, 1995 in Case No. 92-492-B, et al.; letter from Helen C. Helton, Executive Director, dated November 2, 1998, in Case No. 98-523-C. This is highly sensitive information that, if made public, would allow future bidders to know at what prices their competitors are bidding, and would result in the manipulation of the solicitation process to the detriment of LG&E and its ratepayers. Instead of giving its best price and terms in its bid, a CT manufacturers with knowledge of prior bids

could adjust its bid to correspond with LG&E's past bidding history on terms and prices. As a result, LG&E will not get the same quality of bids that would be produced by a system protected by the confidentiality enjoyed by unregulated businesses. Any impairment of LG&E's ability to obtain fair prices for future CTs will increase the capital cost LG&E and its customers will pay for future generation resources.

5. The Companies do not object to disclosure of the confidential information pursuant to a protective agreement entered into with the Attorney General or other intervenors with a legitimate interest in reviewing the confidential information for the purpose of reviewing and commenting on the Companies' 1999 IRP. The Companies will provide a protective agreement to intervenors that is nearly identical to the protective agreement utilized by the parties in KU's last IRP proceeding, Case No. 96-173. This agreement has already been utilized by the Companies and the Attorney General for the limited disclosure of the confidential information contained in the IRP filing in this case.

6. The Commission's January 25; 2000 Order required the Companies to file an original and six (6) copies of the responses to the data requests. Therefore, one copy of the responses to the data requests with the confidential information highlighted and six (6) copies of the responses to the data requests with the confidential information obscured is being filed with the Commission. However, if the Commission wants the full ten (10) copies of the redacted information referred to in 807 KAR 501, Section 7 (2)(b) to be filed, the Companies will comply with a specific request for such a filing.

WHEREFORE, Louisville Gas and Electric Company and Kentucky Utilities Company respectfully request that the Commission grant confidential protection to the information designated as confidential for a period of five years from the date of the filing of the responses to the data requests, or in the alternative, schedule an evidentiary hearing on all factual issues.

Respectfully submitted,

Douglas M. Brooks
Senior Counsel Specialist, Regulatory
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232
(502) 627-2557
Counsel for Louisville Gas and Electric Company
and Kentucky Utilities Company

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing Petition for Confidential Protection was served on this 23rd day of February 2000, by mailing a copy thereof, postage prepaid, through the U.S. Mail to Elizabeth Blackford, Assistant Attorney General, Division of Rate Intervention, P.O. Box 2000, Frankfort, KY 40602-2000; Michael Kurtz, Boehm, Kurtz and Lowry, 2110 CBLD Center, 36 East Seventh Street, Cincinnati, Ohio 45202; Iris Skidmore, Counsel for Natural Resources and Environmental Protection Cabinet, Office of Legal Services, Fifth Floor, Capital Plaza Tower, Frankfort, KY 40601; Mr. Walter F. Bell, Executive Director, Louisville Resource Conservation Council, P. O. Box 4174, Louisville, KY 40204-0174.

Douglas M. Brooks
Counsel for Louisville Gas and Electric Company
and Kentucky Utilities Company

RECEIVED

FEB 23 2000

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN	)	
OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 99-430
AND KENTUCKY UTILITIES COMPANY	)	

RESPONSE TO FIRST REQUEST OF
THE COMMISSION
DATED JANUARY 25, 2000

FILED: FEBRUARY 23, 2000

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q1. Please provide the following annual (redacted) information for the 15year forecast period.

a. The assumed average real price of electricity for LG&E.
b. The assumed average percentage increase in the nominal retail price of electricity for KU.
c. The assumed average nominal percentage increase in the residential price of gas over the next five years and over the next 15 years.

A1. a., b. & c.

This information is confidential and proprietary and not available for public disclosure. The information is being filed with the Commission pursuant to a petition for confidential treatment.

PSC#1-2

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q2. Given the situation in the market for CTs, what specific plans have been made to ensure that LG&E and KU have capacity additions of 480 MW in 2001, an additional 160 MW in 2002, and an additional 160 MW in 2004?

A2. Currently the Companies have an opportunity to acquire two combustion turbines from LG&E Capital Corporation for in-service in 2001. The Companies are in the process of preparing an application for a Certificate of Public Convenience and Necessity ("CCN") to acquire these two combustion turbines. The Companies are staying abreast of other opportunities that may arise in the CT market and are also pursuing the possibility of reserving "slots" with the various CT manufacturers for the purchase of CTs. However, prior to purchasing CTs the Companies will evaluate the purchase power market to determine which type of resource would be most economical at that time.

PSC#1-3

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q3. For LG&E, Technical Appendix I, Volume II:

a. In Table C5 on page C-17, why does the Total Sales column have KWH Sales as the title when the title of this Table says "MWH"? Are sales in KWH or MWH?
b. Why does (Year -1998) enter linearly only in the Residential equation? (In other class' equations, it enters exponentially).
c. Why does (Trend94) enter logarithmically in Small Commercial/Industrial and Large Commercial, Weather-Sensitive Energy Sales equations?
d. Where are the energy price variables in each of the short-term forecasting equations?
e. Why do ACSAT and RSCUST enter the Long-term Air Conditioning equation in double-log form (ln(ln)) on pages 24 and 28)?
f. How were the equations included herein estimated (Ordinary Least Squares, Generalized Least Squares, Other)?

A3.

a. The label for the Total Sales column should have been "Total MWH Sales," not "Total KWH Sales."

b. The choice of an absolute growth (linear) model specification or a growth rate (exponential) model specification for non-weather-sensitive energy sales per customer was based on the trend analysis of base load estimates compiled for the last fifteen years.

c. The choice between a linear trend variable and a logarithmic trend variable was made on the basis of statistical significance test results.

d. Electricity and gas prices in the LG&E service area have been fairly stable in recent years and are insignificant drivers for change in electric energy usage during the five-year period (1994-1998), analyzed for short-term energy sales model development. Base rates for both electricity and gas were fixed and changes in electric generation and gas fuel costs were insignificant throughout the five-year period.

e. The model equations for both the average number of persons per residential customer and composite rate of residential air-conditioning saturation were developed by using the Gompertz curve fitting. The mathematical expression of the Gompertz curve has a double exponential form and takes a double logarithmic form when being converted into a log linear form for regression analysis.

f. The equations were estimated by Ordinary Least-Squares ("OLS") Estimation Methods. The estimated values of intercept term and time variable coefficient were then converted exponentially before entering the double logarithmic equation forms presented in pages 24 and 28.

PSC#1-4

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q4. How do the assumptions for the Optimistic and Pessimistic outlook differ from those of the Baseline Forecast?

A4. As shown in Section B of Volume II, Technical Appendix, the assumptions for the baseline, the optimistic, and the pessimistic outlooks differ in the projected values of the economic and demographic variables used in the energy sales, peak demand and customer forecasting model equations. The primary input variables controlled to develop the different growth scenarios were population, real per capita income, real price of electricity by class, and employment by sector. Except the case of electricity prices in which lower growth rates were assumed for the optimistic scenario, the annual growth rates of those economic and demographic variables are higher in the optimistic outlook than the growth rates assumed for the baseline forecast. The situation is opposite for the case of pessimistic outlook.

PSC#1-5

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q5. For KU, Volume II:

a. In KU-7 on page 17, the Kentucky retail price forecasts are displayed both for the 1999 IRP and that from 1996.
   i. Why are prices expected to dramatically increase from 2000 to 2003 and then fall precipitously in 2004?
   ii. Why are the prices forecasted for the 1999 IRP so far below those that were forecasted in the 1996 IRP?
b. Why are the RS and FERS rate classes treated differently in the REEPS model (see, for example, page 20, 2nd full paragraph)?
c. In the short-run RS Monthly KWH on page 34:
   i. Where are the t-statistics that correspond to the estimated parameters of this equation?
   ii. What comprises the variable $RSPRICE_{-1}$? In other words, does it include the adjustments to base rates (FAC, Merger Surcredit, etc.) or just base rates themselves? By how much does RSPRICE vary from month to month?
   iii. How was the equation estimated (Ordinary Least Squares, General Least Squares, other)?
d. In the FERS short-run equation for Monthly kWH, provide a better explanation as to the reason that July, February, and March are included as binary variables.
e. In the COMCUST equation on page 48, why are commercial customers forecast as a function of residential customers?
f. In the HEATING Season: KWH per customer equation on page 50:
   i. Where is the Real Average Commercial price variable and what is its estimated coefficient?
   ii. What is the estimate of rho (p), the coefficient of ARI? Why is it included in the Cooling Season equation, but not in the Heating Season?
   iii. How was this equation estimated (Generalized Least Squares, Cochran -Orcutt, Other)?
g. Why are the first differences of the variables used to estimate the industrial KWH equations?

A5. a. i. This information is confidential and proprietary and not available for public disclosure. The information is being filed with the Commission pursuant to a petition for confidential treatment.

a. ii. This information is confidential and proprietary and not available for public disclosure. The information is being filed with the Commission pursuant to a petition for confidential treatment.

b. The two rate classes are treated differently because they exhibit unique usage and revenue characteristics. The two customer classes are defined based on end-use ownership. The FERS class rate is provided to households who have the capability to meet their total end-use requirements with electricity. All other residential customers are provided service on the RS rate schedule. Such a classification results in different usage patterns, especially during the heating season. In addition, each class is assigned two different rate structures; therefore, they exhibit different revenue flows.

c. i.

TABLE 5-Ci
RS VARIBLE T-STATISTICS

Variable	T-Statistic
$RSPRICE_{-1}$	-6.5951
KPC_{-1}	1.8547
JANHDD	12.2379
FEBHDD	8.1554
MARHDD	5.1436
APRHDD	3.8795
MAYCDD	2.2307
JUNCDD	11.8398
JULCDD	25.3811
AUGCDD	21.6586
SEPCDD	14.7501
OCTCDD	4.2632
NOVHDD	2.5616
DECHDD	7.7842

c. ii. $RSPRICE_{-1}$ is the average monthly net price (with all adjustments) indexed by the CPI applied to the RS class lagged one period. The percent changes shown in Table 5-cii are indicative of the monthly price relationships.

TABLE 5-cii
RS PRICE MONTHLY CHANGES

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1999	-4.2%	5.0%	-0.9%	0.1%	2.1%	-4.6%	-2.7%	1.3%	-2.0%	3.6%	2.8%	-1.7%

c. iii. The short-run RS model was estimated using Ordinary Least Squares.

d. These binary variables are included because statistically they contribute to the overall fit of the model. They reflect the existence of some anomaly in those month's billing data that has not been captured by the other model terms.

e. Residential customer growth is a good predictor of commercial customer growth.

f. i. For the 1998 forecast, the model was run with Real Commercial Price and the t stat was -0.269. It is a very weak fitting variable and thus was not used in the 1999 forecast estimation process.

f. ii. The estimate of rho for the first order autocorrelation for the summer equation is -0.575. For the heating season, rho is –0.252.

The Durbin-Watson (D-W)Statistic was used to determine serial correlation. The D-W statistic can range in value from 0 to 4. A D-W Statistic that is significantly less than 2 indicates positive serial correlation, and a D-W statistic significantly greater that 2 indicates negative serial correlation. For the Heating Season equation, the D-W Statistic was 2.49; therefore this equation did not definitively indicate

PSC#1-6

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q6. Refer to page 5-21 of the IRP, specifically the last sentence that indicates the difference between KU's summer and winter peaks is expected to narrow over the forecast period. Identify the factors and/or reasons to which KU attributes this narrowing between its summer and winter peaks.

A6. The forecasted growth in the all electric residential area, which increases the winter peak, and a reduction in growth in the general residential area, which decreases the summer peak, will cause the narrowing between the summer and winter peaks.

PSC#1-7

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q7. Refer to page 5-35 of the IRP that references the Request for Proposal ("RFP")issued in September 1999 to the three major Combustion Turbine ("CT") manufacturers. Regarding this RFP, provide the following information.

a. The actual RFP issued to ABB, GE, and Seimens Westinghouse.

b. If already received, the responses from each of the three manufacturers.

c. Identify any 'minor' CT manufacturers that were not issued the RFP and explain the reasons for not seeking proposals from them.

A7. a. The actual RFP issued to ABB, GE, and Seimens Westinghouse is attached.

b. The responses to the RFP are being filed as confidential and proprietary information. The information is being filed with the Commission pursuant to a petition for confidential treatment.

c. The Companies believe that the responses from these manufacturers represent the large frame combustion turbine market. The Companies are continually assessing the CT market availability from these manufacturers as well as from other vendors of products that could be economically viable.

September 27, 1999

GE Power Systems
4079 Executive Parkway
Suite 310
Columbus, OH 43081

Attn: John Newcomer and J. Mark Friday
Fax Nos. (513) 777-4981 and (614) 899-8908

Subject: Request For Updated Proposal: Combustion Turbine Generators
Ref: RFP No. 2153-1
GE Proposal Dated April 30, 1999

Dear Sirs:

LG&E requests that G E Power Systems update the budgetary proposal of April 30, 1999 for the five (5) combustion turbines quoted in response to our RFP no. 2153. Please ensure that your updated proposal, if accepted, can form the basis for a firm order.

The attached specifications remain the same as those in the original RFP and are enclosed for your review.

Your updated proposal should include the following minimum information:

- Pricing Valid for 60 days to allow LG&E sufficient time for review and management approvals
- Performance Guarantees
- Emissions Guarantees
- Delivery time for one (1) through five (5) turbines.
- Estimated Freight cost for delivery to either Central Kentucky or Louisville areas
- Progress Payment Terms.

Bid Due Date at 4:00 p.m, Tuesday, October 19, 1999.

Please affix the enclosed special bid label to your updated proposal, mark your proposal with the information below, and send it to the following address:

LG&E Energy
c/o Strategic Sourcing/Procurement Team
820 West Broadway
Louisville, KY 40202

Attn: K.E. Black
REF: RFP No. 2153-1
BDD: October 19, 1999

Fax proposals are not acceptable. If you send your proposal by courier, please place your proposal in a separate envelop, affix the sealed bid label, and then place your sealed bid in the courier package. This will ensure that your proposal remains sealed until opened after the Bid Due Date.

An original (1 set) and two copies (2 sets) of your proposal are required to expedite our management review and final approval process.

Please contact Noel Lively at telephone number (606) 748-4620 with any technical questions. Contact me at telephone (502) 627-2219 with any commercial questions, or Don Carpenter at (502) 627-2798 during the week of 10/11/99.

K.E. BLACK, C.P.M.
Strategic Sourcing/Procurement Team
Tel. (502) 627-2219
Fax (502) 627-3646

Cc: Noel Lively, KU Generation Construction
Lonnie Bellar, Generation Systems Planning
R.T. Melloan, LG&E Generation Services
Don Carpenter, Strategic Sourcing/Procurement Team

Re: **Request for Proposals**

LG&E Energy Corp. (LG&E) requests proposals for Combustion Turbine Generators. Due to increased demand in the Kentucky Utilities and Louisville Gas and Electric service territories, LG&E has a need for additional peaking capacity. It is the intent of LG&E to compare the results of this request with competing alternatives, namely purchase power and load management, to determine the most reliable least cost approach to meet future needs. The timing of the purchase of the requested machines is dependent on this analysis and future load requirements, and may require Kentucky Public Service Commission approval.

This request should be considered to be in addition to any ongoing work with LG&E Power Inc. (LPI). However, LG&E will evaluate the offerings resulting from this RFP in conjunction with LPI to ensure the lowest overall cost of CT procurement.

LG&E desires to take advantage of manufacturer standard design and offerings; therefore, the limited requirements of this specification. It is expected that each bidder shall submit drawings and detailed descriptive matter indicating general dimensions, principles of operation, operating history, and materials of construction to allow proper evaluation of the offering. Any proposal not having sufficient descriptive matter to describe accurately the equipment or materials proposed may be rejected.

1.0 GENERAL REQUIREMENTS

Proposals for multiple machines are requested as described in 3.0 and 4.0 below. It is understood, however, that pricing for all units in Section 4.0 after the first unit is contingent upon the award of all machines up to that number. The following requirements shall apply to all machines quoted.

1.1 All equipment and materials required for complete combustion turbine generating units shall be quoted as F.O.B. jobsite.

1.2 Machines shall be natural gas fired with No. 2 fuel oil firing quoted as an option.

1.3 Base bid shall include equipment and materials only. Please quote options (1) field service representation for both erection and startup and (2) operation and maintenance training, indicating the number of days included for each.

1.4 Site conditions to be used as design and performance criteria are as follows:

	Performance Rating		Design Range
Ambient dry-bulb temp, °F	90		-25 to 105
Relative humidity, %	50		20 to 100
Barometric Pressure, psia		14.3	
One percent design wet-bulb, °F		78	
Average relative humidity, %		70.5	
Average annual precipitation, in		44.5	

1.5 Bidder shall submit complete and definitive information in sufficient detail to permit a complete analysis of the proposal. Additional information shall be provided as requested by the Purchaser. The scope of supply, performance curves, drawings, purchaser interface points, supplementary information, and equipment data shall be included in the proposal to the fullest extent possible at the time of bid submittal. Performance and emission data shall be supplied for both natural gas and No. 2 fuel oil firing.

1.6 Base bid shall be for manufacturer's standard outdoor design.

1.7 An option price shall be quoted that considers the turbine and compressor

footprint within a purchaser furnished building with the capability of being services with a purchaser furnished overhead crane.

1.8 Pricing shall be provided for erection of the equipment furnished, as an option. The erection option shall be quoted for each unit individually. If the Purchaser chooses the erection option, appropriate terms and conditions will be negotiated at a later date.

2.0 GUARANTEES

The combustion turbine generator shall operate safely, reliably, and without undue maintenance or operator attention. Guarantees shall be such as can be met in everyday operations under all operating conditions. Guarantees, which shall be clearly stated in the proposal, shall include but not be limited to electrical capability, heat rate, starting time, minimum load (stable? Or emission control based?), noise limits (near and far field and exhaust conditions (NO_x CO, VOC, PM_{10}). Performance shall be guaranteed when burning either natural gas or No. 2 fuel oil. Capability and performance tests will be conducted by the Bidder to verify each unit's guaranteed conditions as defined. Remedies for non-compliance to guarantees shall be proposed individually for each guaranteed item.

3.0 E.W. Brown Machine Specifications

One complete, simple cycle, combustion turbine generator shall be quoted with a nominal rating of 110 to 190 MW. This machine will be installed at the Purchaser's existing E. W. Brown Combustion Turbine Generating Facility near Burgin, Kentucky.

3.1 A site layout drawing of the E. W. Brown facility is included, indicating the existing facility arrangement. The bidders shall provide an arrangement drawing showing the combustion turbine incorporated into the existing site and utilizing the existing 85 ton overhead bridge crane.

3.2 This machine shall have remote operation capability from two separate locations.

3.3 The earliest, start of delivery and completion of delivery of this unit shall be stated in the proposal.

4.0 Greenfield Machine Specifications

Four (Units 1, 2, 3, and 4) identical, simple cycle combustion turbine generators shall be quoted with nominal ratings of 160 – 190 MW each. These machines are to be installed at a yet to be specified, greenfield site.

4.1 Each unit shall have the capability of remote operation.

4.2 The proposal shall address the suitability of the four offered units for future adaptation from simple cycle to combined cycle use. Design considerations, performance expectations, cost estimate, outage requirements, etc., should be included and will be strongly considered in the evaluation of proposals.

4.3 The earliest, start of delivery and completion of delivery of these units shall be stated in the proposal.

5.0 PRICING

Firm lump sum pricing shall be provided. Machines and options shall be quoted individually to facilitate the evaluation.

6.0 SCHEDULE FOR BIDDING

Bids are requested to be submitted by April 15, 1999. This RFP is not a commitment to purchase and shall not bind LG&E Energy in any manner. The bids will receive serious consideration and the Bidders will be notified of the status of their proposals.

7.0 CONTACT INFORMATION (Revised)

Questions concerning this RFP or requests to visit the E. W. Brown site shall be directed to:

Noel Lively
Manager, Generation Construction
Kentucky Utilities Co.
E. W. Brown Combustion Turbine Generating Facility
P.O. Box 510
Burgin, Kentucky 40310
(606) 748-4620
(606) 748-4628 FAX

PSC#1-8

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q8. Refer to page 6-4 of the IRP that discusses the changes in the population forecasts for LG&E's service territory from its 1993 IRP filing to the 1999 IRP.

a. Was the University of Kentucky's Center for Business and Economic Research the source used for population forecasting in LG&E's 1993 IRP?

b. If no, identify the entity that was the source of the previous population forecast, and explain why LG&E chose to make a change for this IRP.

Q8. a. No.

b. The population forecast provided by the University of Louisville was used in LG&E's 1993 IRP. In 1999, both the University of Louisville's ("U of L's") and University of Kentucky's ("UK's") forecast services were available. The dual forecast services became available when LG&E and KU merged. LG&E has been using U of L's local economic and demographic forecasts while KU has been using UK's forecasts. The local population forecast provided by UK was selected for the 1999 IRP, on the basis of the recent growth trend of LG&E's residential customers. U of L's population projections were evaluated to be too low to reflect the local demographic growth trend implied by the increase in number of residential customers experienced during the last several years.

PSC # 1-9

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q9. Refer to page 6-5 of the IRP which refers to the six-year difference in the 20-year "average weather" study (1979-1998) reflected in the current IRP compared to the comparable study reflected in the 1993 IRP (1973-1992). Provide, in summary form, the results of those studies, and a description of the impact of the new study on the 1999 energy and demand forecasts included in the current IRP.

A9. The difference between the twenty-year average values of the weather variables is summarized as follows:

Period	Annual HDD	Annual CDD	THI for 24 hrs. before Summer Peak Demand	HDH at the Time of Winter Peak Demand
'73-'92	4,427	1,387	78.5	54.8
'79-'98	4,290	1,506	78.9	57.7
Diff.	137	119	0.4	2.9
% Diff.	3.1%	8.6%	0.5%	5.3%

Impacts of the difference in normal weather values assumed for 1993 IRP and 1999 IRP forecasts of energy sales are not readily identifiable. There are twenty weather-sensitive energy sales equations to be simulated for different weather conditions. Separation of the impact caused by changes in weather variable coefficients will be another problem. Using the 1999 IRP model coefficients, impacts of using the higher THI and HDH values on LG&E's seasonal peak load forecasts for 2000 are estimated to be 20 MW on summer peak and 27 MW on winter peak.

PSC#1-10

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q10. Refer to page 6-1 1 of the IRP. Explain the reasons for the use of separate models for wholesale sales to the cities of Pitcairn, Pennsylvania and Paris, Kentucky compared to KU's other wholesale customers.

A10. The two municipalities Pitcairn and Paris were separated because they are under different contracts than the other wholesale customers.

PSC# 1-11

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q11. Refer to page 6-16 of the IRP regarding the renovation of the Ohio Falls generating station. Identify and describe any developments regarding this project since the time the IRP was prepared.

A11. The Companies are still evaluating the rehabilitation of the Ohio Falls generating station.

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q12. Refer to page 7-12 of the IRP which states that WEFA's 20-year long-term forecasts released in the first quarter of 1993 were utilized as inputs for national economic and demographic variables. Explain whether the reference to "1993" is correct, and if so, explain why more current forecasts were not utilized for the inputs previously described.

A12. The reference to "1993" was a typo. It should have been "1999."

PSC # 1-13

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q13. Refer to page 7-23, specifically Table 7(7)(d)-2, of the IRP. In general, identify and describe the factors that account for the difference between the Optimistic and Base forecasts being consistently greater than the difference between the Base and Pessimistic forecasts.

A13. Asymmetry of the optimistic and the pessimistic forecasts of service area population around the base forecast is the major reason for the difference between the Optimistic and Base forecasts of energy and demand being consistently greater than the difference between the Base and Pessimistic forecasts. For example, the annual population growth rate projected for 2000 is 0.49% for the base case, 0.90% for the optimistic case, and 0.23% for the pessimistic case. The absolute growth rate gap between the base and the optimistic cases (0.41%) is significantly higher than the gap between the base and the pessimistic cases (0.26%). The same pattern of asymmetry is prevalent throughout the forecast horizon. In 2013, the projected annual population growth rates are 0.50% for the base, 0.69% for the optimistic (+0.19% from the base), and 0.39% for the pessimistic scenario (-0.11% from the base). Population projections were prepared by the University of Kentucky using their regional econometric model and WEFA's twenty-year macroeconomic forecasts released in the first quarter of 1999.

PSC#1-14

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q14. Refer to page 7-52 of the IRP, specifically the reference to "cooling degree-days using a 70-degree base." Many utilities use a 65-degree base for calculating cooling-degree days. Indicate when KU began using a 70-degree base in determining cooling degree-days, and whether this was the result of an in-house study or was based on an industry analysis performed by an outside source.

A14. Page 7-52 refers to the use of a 70-degree base in the development of the annual Industrial Sector sales model. Industrial sales show some sensitivity to hot weather, but air conditioning load is typically less a factor in terms of overall load than is the case for Residential or Commercial Sector sales. The 70 degree day base has been used for this sector since the forecast developed in 1996 (the 1997 Forecast) and tests more significant than a 65 degree base.

PSC#1-15

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q15. Refer to page 7-60 of the IRP. Provide a more detailed discussion of how the probabilities identified in the table were derived, particularly focusing on the reasons for the much greater probability assigned to the Pessimistic Forecast as compared to the Optimistic Forecast. Also explain in greater detail the reasons for why the probability of the Optimistic Forecast occurring might be understated as stated in the text on that page.

A15. To derive the probabilities of Table7.(7)(d)-2, the following steps were taken:

- The variance between the actual and the 2000 backcast was calculated. The standard deviation of these calculated variances was found. Call this the historical standard deviation.
- Next, the midpoints between the base and optimistic forecast and between the base and pessimistic forecast were calculated. This creates three scenario ranges of sales - a pessimistic range which is from zero sales to the midpoint of the pessimistic and baseline forecasts, an optimistic range which extends from the midpoint of the optimistic and baseline forecasts upward, and a baseline range which is the area between the two midpoints.
- The EXCEL function NORMDIST was calculated for each scenario. This function returns the normal cumulative distribution for a given value, specified mean and standard deviation. The given value here is the upper or lower value of the baseline range, the mean is the baseline forecast, and the standard deviation is the historical standard deviation.
- For each scenario, this cumulative function gives the probability that the load will be less than the bottom value of the baseline range (pessimistic cumulative probability) or up to the top of the baseline range (optimistic cumulative probability). Given this, the probability that the load will be greater than the top of the baseline range (or optimistic) is one minus the optimistic cumulative probability. This is the probability of the optimistic scenario. The probability that the load will be less than the bottom of the baseline range (or pessimistic) is the pessimistic cumulative probability. This is the probability of the pessimistic scenario. Therefore, the probability of the baseline range is one minus the optimistic and pessimistic scenarios.

The main reason that the pessimistic forecast has a greater probability of occurring is because of the nature of the two scenario forecasts. The optimistic forecast is 1.35 percent higher than the base forecast while the pessimistic forecast is only 0.03 percent lower. The pessimistic forecasts did not have as large of a differential range as the optimistic forecasts. Thus, since the pessimistic forecast is so close to the base, there is a greater chance of it occurring. Therefore, the probability of the optimistic forecast occurring would be understated relative to an analysis which had a symmetric spread between the baseline forecast and the optimistic and pessimistic scenarios.

PSC#1-16

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q16. Refer to page 8-2 of the IRP which refers to the potential installation of Inlet Air Cooling ("AIC") at Brown Stations 8-11. Are Brown Stations 6 and 7 already equipped with AIC? If not, explain why they are not included along with Stations 8-11.

A16. Brown Units 6 and 7 are not equipped with Inlet Air Cooling (IAC). Instead, the two combustion turbines are equipped with an evaporative cooling system. The evaporative coolers were included as part of the original construction of the two machines, which were completed in August 1999. While evaporative cooling and IAC are not absolutely mutually exclusive, the two systems do perform similar functions; the additional expense to install Inlet Air Cooling on two machines that already have evaporative coolers in place is not justified.

PSC#1-17

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q17. Refer to page 8-5 of the IRP which refers to the installation of Distributive Control Systems ("DCS") at various LG&E and KU units. Provide the status of any current plans for installing DCS at any other units not identified in the discussion on page 8-5.

A17. As mentioned on page 8-5 of the IRP, the Companies have plans to install DCS systems on Brown 1, Ghent 1, and Mill Creek 1 during the next two years. The Mill Creek upgrade is currently in progress. Trimble County Unit 1 was installed with DCS systems. The remaining units that have not had DCS systems installed or upgraded (Mill Creek 2, 3, and 4 and Pineville 3) will be evaluated in the future. As the economic evaluation indicates that the projects should be pursued, the Companies will develop a workplan for the remaining units.

PSC#1-18

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q18. Refer to pages 8-8 and 8-9 of the IRP which describe LG&E's installation of additional capacitors on it distribution system to provide more efficient use of substation transformer capacity and its modified guidelines that allow substation distribution transformer loading up to 120 percent of top nameplate rating, during contingency conditions.

a. Provide the source and results of the referenced studies that have shown that loading up to 120 percent of top nameplate rating for short periods of time causes no appreciable loss of life.

b. Is this limited to LG&E or is KU also doing this? If no, explain why KU is not pursuing similar distribution system efficiencies.

A18. a. The guidelines for the loading of the LG&E distribution transformers to 120% of top nameplate rating during contingency conditions was established using an in-house program in conjunction with an EPRI program PTLOAD. Both programs are based on the ANSI C57.92-1981 loading guide. Attached are the results of the study.

b. The guidelines referenced in the IRP apply to the LG&E system. KU has a similar guideline to which distribution transformers are loaded above their nameplate rating. It is also based upon the ANSI C57.92-1981 loading guide.

The guidelines were based solely on the insulation deterioration of the transformer windings. Other items such as oil expansion space, ratings of bushings, tap changers and leads should be considered before overloading a given transformer. Stray flux heating can become a problem in transformers greater than 100 MVA and the risk of failure, during overloads, is much greater.

TRANSFORMER TEMPERATURE LIMITS (65°C RATED)

110°C Top Oil
140°C Hot Spot

LOSS OF LIFE LIMITS

DURATION OF EMERGENCY	LOSS OF LIFE ALLOWANCE
6 months (130 load days)	15.0 %
1 month (22 load days)	10.0 %
1 week (5 load days)	3.5 %
2 hours - 1 day	1.5 %

The winding hot spot of 140°C is usually the first limit reached. The hot spot limit was established to prevent the formation of gas bubbles in the insulation system. Gas bubbles result in temporary reduction of the dielectric strength. This could result in instantaneous failure if a transient over-voltage occurs while the insulation is in this weakened state, or perhaps even at normal operating voltages.

Using the above limits the following table was established as a loading guide:

ALLOWABLE SUMMER (98°F DAY) AND WINTER (50°F DAY) LOADING IN PER UNIT OF 65°C TOP RATING

Duration of Emergency	Summer Load	Limiting Factor	Winter Load	Limiting Factor
0 (Normal)	1.07	Loss of Life	1.26	Loss of Life
15 minutes	1.35	Hot spot	1.66	Hot Spot
30 minutes	1.29	Hot spot	1.55	Hot Spot
1-hour	1.25	Hot spot	1.47	Hot Spot
2-hours	1.20	Hot Spot	1.40	Hot Spot
10-hours	1.19	Hot Spot	1.37	Hot Spot
1-day	1.19	Hot Spot	1.36	Hot Spot
1-week	1.19	Hot Spot	1.36	Hot Spot
1-month	1.19	Hot Spot	1.36	Hot Spot
6-months	1.15	Loss of Life	1.34	Loss of Life

This guideline should be used for planning purposes. Specific transformers can be analyzed on a case by case basis if necessary with more accurate specifications and possibly real time load and temperature data.

The following assumptions were made in the computer runs used to establish the guideline.

Typical transformer characteristics were used.

A normalized 1993 peak day system 24 hour load curve was used.

A 98°peak summer 24 hour temperature curve and a 50°peak winter temperature curve was assumed.

1% average moisture content in the insulation

Bubble formations were tested at 0.64% and 1.5% moisture content at the hot spot.

A transformer with a 26.9/32/44.8 MVA OA/FA/FA (65°C average winding rise) rating was simulated.

A nitrogen gas blanket at 999 mm Hg pressure for oil preservation was used.

A 48 inch static head of oil above hot spot was simulated.

Overloads of 2 hours and less were assumed to increase to a constant load for the length of the overload and then return to the daily load cycle.

All overloads greater than 2 hours were assumed to have a daily load cycle with a step increase to a similar load cycle for the length of the overload and then return to the daily load cycle.

The daily load cycle with a magnitude of 1.0 per unit was used to establish the pre-load state of the transformer.

PSC#1-19

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q19. Refer to the table on page 8-75 identified as "Total Electricity Production Costs." Was 1.65 cents per Kwh representative of LG&E's and KU's generation costs in 1998 as if their rates had been unbundled? If not, identify and explain the adjustments or modifications that would be required in order to derive a representative rate for generation and show the derivation of the rate(s).

A19. The Companies do not have the requested information, but are planning to respond to the Commission pursuant to Orders in Case Nos. 98-426 and 98-474.

PSC#1-20

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: William A. Bosta

Q20. Provide the following information related to the existing rate programs identified on pages 8-80 and 8-81 of the IRP.

a. The number of customers on KU's CWH rate schedule.
b. The number of customers served and the MW available for curtailment under KU's CSR rate schedule.
c. The number of customers served on KU's Time-of-Day rate schedules and the estimated impact of those schedules on KU's peak demand.
d. The number of customers taking service under LG&E's Interruptible Service Rider and the MW subject to interruption.
e. The number of customers served on LG&E's Time-of-Day rate schedules and the estimated impact of those schedules on LG&E's peak demand.

A20. a. In 1999 there were 10,997 customers served under KU's CWH rate schedule.

b. In 1999 there were 8 customer accounts under KU's CSR rate schedule with a total of 32.5 MW contracted as available for interruption. A total of 28 MW is considered actually available for interruption due to the customers actual load characteristics.

c. In 1999 there were 37 customers served on KU's Time-of-Day rate schedule. For December 1999 the coincident peak demand of the TOD customers was 370,798 kW which accounts for 12.25% of the KU system peak (3,027,000 kW) for December 1999. KU does not know the impact of the TOD schedules, but believes customers fully account for the service cost and conditions in their energy consumption decisions.

d. In 1999 there were 10 customer accounts under LG&E's Interruptible Service Rider with a total of 121 MW available for interruption.

e. In December 1999, there were 53 Large Commercial Time-of-Day (LC TOD) customers and 58 Large Power Time-of-Day (LP TOD) customers. The estimated contributions to the peak demand were 99 MW for LC TOD and 149 MW for LP TOD excluding those on the Interruptible Service rider. LG&E does not know the impact of the TOD schedules, but believes customers fully account for the service cost and conditions in their energy consumption decisions.

PSC#1-21

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Gregory B. Fergason

Q21. Refer to the discussion on page 8-81 of the IRP concerning the proposed Direct Load Control program. Provide, in summary form, a description and the results of any similar programs either LG&E or KU has implemented in the past 10 years (1990-1999).

A21. No similar programs have been implemented in the past 10 years.

PSC#1-22

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q22. Refer to the discussion on page 8-81 of the IRP regarding Standby Generation. Provide the total number of customers, on both systems, that have back-up generating facilities, and the estimated MW potential of such a program.

A22. No specific information has been obtained for either system.

PSC#1-23

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q23. Refer to the table on page 8-85 of the IRP. Explain why the impact of interruptible rates is shown at 121 MW in 1999 and only 80 MW for subsequent years.

A23. Approximately 30 MW of the impact on the amount of interruptible load available to the Companies is a result of companies leaving the interruptible rate schedule. Approximately 22 MW is due to the reduction in load at several customers under the interruptible rate schedule. However the reductions are somewhat offset by the increase of approximately 11 MW in the interruptible load of several other customers.

PSC#1-24

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q24. Refer to the tables on pages 8-89 and 8-90 of the IRP showing resource capacity available over the forecast period. Appendix A, Table 2, shows the in-service dates of all generating units. Given the age of some of the units, explain why the projected resource capacity available for the forecast period does not reflect any planned retirements.

A24. No retirements were assumed on existing units when preparing the IRP. An economic evaluation of each unit would be required to determine if it is more economical to retire a specific unit at a point in the future. If a unit becomes unreliable such that it cannot provide a high level of service to the ratepayers, such an economic evaluation will be undertaken to determine, at that point in time, whether it would be economically justified to retire the unit and replace its generation from another source.

PSC# 1-25

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q25. Refer to page 8-100 of the IRP that indicates our current Clean Air Act Compliance Plan includes installation of a scrubber on Ghent 2 in 2003. If nothing changes to alter this plan, provide the approximate timetable for filing an application for a Certificate of Public Convenience and Necessity.

A25. Throughout the year 2000, the Companies will continue to evaluate the plan to install a scrubber on Ghent 2. If nothing changes the current plan to install a scrubber on Ghent 2 in 2003, then the Companies expect to file an application for a Certificate of Public Convenience and Necessity in 2001.

PSC#1-26

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q26. Refer to page 8-102 of the IRP describing the events of July 30, 1999. Provide a detailed description and explanation for why LG&E's "actual interruptible was 75 megawatts less than anticipated."

A26. The statement made on page 8-102 is a misstatement of the impact of LG&E's interruptible load. At the time the IRP was prepared, the total actual impact of the LG&E interruptible load was not known. In Table 8.(5)(b) the "Actual LGE Interruptible Impact" of 48 MW represents the load of the interruptible customers who were buying their power from the market and were not being provided power from the Companies' generation. This amount is only a portion of the load reduction due to interruptible customers. The remaining reduction (the load of the customers who actually interrupted service) was not known.

PSC#1-27

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q27. Refer to pages 8-111 and 8-112 of the IRP regarding Supply-side Screening. Provide the percentage increases in cost for TAG Supply technologies 15.1, 15.2, and 15.3 based on current bid prices for these sizes and types of CTs.

A27. The process capital cost and engineering fees from TAG Supply for technologies 15.1, 15.2, and 15.3 were adjusted by multiplying the TAG cost by 92.3% to reflect the then current market price for combustion turbines. This is based upon a ratio of the then current cost of a 160 MW CT installed to the TAG Supply cost for a comparable machine.

PSC# 1-28

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q28. Refer to pages 8-125 and 8-126 of the IRP regarding NOx emission rates.

a. Identify which existing generating units have tangentially-fired boilers and which have dry-bottom, wall-fired boilers.
b. Provide the scheduled installation dates for the advanced low NOx burners on Ghent Units 2, 3 and 4.

A28. a. The table below identifies which coal units have tangentially-fired boilers and which have wall-fired boilers.

Unit Name	Boiler Firing Mechanism
Brown 1	Wall
Brown 2	Tangential
Brown 3	Tangential
Cane Run 4	Wall
Cane Run 5	Wall
Cane Run 6	Tangential
Ghent 1	Tangential
Ghent 2	Tangential
Ghent 3	Wall
Ghent 4	Wall
Green River 1	Wall
Green River 2	Wall
Green River 3	Wall
Green River 4	Wall
Mill Creek 1	Tangential
Mill Creek 2	Tangential
Mill Creek 3	Wall
Mill Creek 4	Wall
Pineville 3	Wall
Trimble County 1	Tangential
Tyrone 1	Wall
Tyrone 2	Wall
Tyrone 3	Wall

b. The installation of the advanced low NOx burners on Ghent 2 is scheduled to occur in the spring 2000, while installation on Ghent 3 was in 1998, and installation on Ghent 4 was in 1999.

PSC#1-29

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q29. Refer to the discussion on page 8-128 of the IRP concerning the Sargent & Lundy system-wide NO_x compliance study.

a. Provide the date the study was initiated and its expected completion date.

b. Could the results of this study potentially alter LG&E's and KU's current CAAA compliance plan? Is yes, in what ways?

A29. a. Sargent & Lundy was engaged in January of 1999 and completed their report in May 1999.

b. No, the installation of NO_x control technologies does not significantly impact SO_2 emission except for a slight change in dispatch due to additional variable operation and maintenance expense.

PSC#1-30

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Gregory B. Fergason

Q30. Refer to the Technical Appendix, specifically the DSM Analysis. One of the programs that failed the benefit-to-cost analysis was the DLC water heater program for residential customers. Provide the cost estimates and other supporting data that resulted in the TRC test result of .87 for this program.

A30. Please refer to Exhibit DSM-6 in the Section IV DSM Analysis of Volume III Technical Appendix.

PSC#1-31

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of PSC Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q31. Refer to the Technical Appendix, specifically the CAAA Compliance Analysis. The text of this analysis would seem to suggest that the plan to install a scrubber at Ghent 2 is still being evaluated. However, the discussion on page 8-100 of the IRP and other points of reference, states that your current Clean Air Act Compliance Plan includes, among other things, installation of a scrubber at Ghent 2. Is this issue still being evaluated or has the decision been made? Explain the reasons for the discrepancy in the text of the IRP and text of the CAAA Analysis in the Technical Appendix.

A31. As stated, the Companies' current Clean Air Act Compliance plan includes the installation of a scrubber on Ghent 2 and the switch to high sulfur coal for that unit. However, this decision will continue to be evaluated to determine the impact that Phase II may have on the fuel markets. Throughout the year 2000, the Companies will monitor the cost of the various fuel types to determine if it is still the most economic decision to install a scrubber on Ghent 2 and fuel switch to high sulfur coal for that unit.

Rec 2/23/2000
SW

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

THE JOINT INTEGRATED RESOURCE PLAN	)	
OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 99-430
AND KENTUCKY UTILITIES COMPANY	)	

RESPONSE TO FIRST REQUEST OF
THE ATTORNEY GENERAL
DATED JANUARY 25, 2000

FILED: FEBRUARY 23, 2000

RECEIVED

FEB 23 2000

PUBLIC SERVICE
COMMISSION

AG#1-1

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q1. On page 5-23 of Volume I, the assumption is stated that the future climate will reflect the weather values of the most recent twenty-year period. Recent weather data shows that global temperatures are rising rapidly, as seen in the high temperatures in the last decade. Please explain why the past twenty years is a good assumption for future temperatures.

A1. KU does not accept the premise of the question that temperatures have been rising rapidly. However, KU has used a 20 year rolling average for energy forecasting since at least the early 80's. LG&E began using the 20 year rolling average with the 1993 IRP. Each company has preferred to use 20 years rather than a 30 year NOAA average. In that context, KU's and LG&E's weather normalization is more robust to capturing a warming trend than it would be using the NOAA average.

AG#1-2

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q2. On page 5-24 of Volume I, it is stated that the appliance efficiency standards from the 1992 National Energy Policy Act were included in the KU forecast:

a. Please provide a detailed explanation of exactly how these appliance standards were incorporated in the forecast.
b. Were these standards included in LG&E's forecast? If so, please explain how. If not, please explain why not.

A2. a. Efficiency standards are entered in the exogenous variable portion of the model. This module provides a database for the equations of the model. The HVAC module, which provides the framework for estimating equipment purchases, equipment survival, and energy use, taps into this database and uses these appliance standards for modeling heating and cooling equipment efficiency. Also the appliance model, which provides the general framework for modeling appliance survivals, purchase decisions and energy uses for those household appliances other than HVAC, utilizes these standards from the exogenous database for modeling efficiency choice equations. The standards for each end-user are shown in Volume II of the IRP in Subsection 3, Data Series, pages 3-5, tables titled End-Use Historical/Forecast.

Each variable represents a particular appliance standard and is expressed in technology terms relevant to that appliance. For example, Freezer standards are expressed in Energy Factors and Central Air Conditioning standards are expressed in a SEER level. The exogenous variable file organizes the standards data that is later used in any new purchase decision including replacements and new purchases acquisitions. In the model, the range of appliance efficiency options available on the market is explicitly represented, and the imposition of standards limits the bottom of this range so that no purchases are allowed below the legal minimum. Since the efficiency range is limited in each year, the mix of appliances purchased will have a higher average efficiency level. As these appliances are mixed in with the surviving stock from previous years, the overall average efficiency level rises. As efficiency levels rise, the energy use required for a given level of service declines.

b. The appliance efficiency standards were not explicitly included in LG&E's forecast, but were implicitly considered.

   LG&E's short-term energy sales model equations were estimated with the historical data for 1994-1998, the time period two years after the 1992 National Energy Policy Act. Coefficients of the annual trend variables included in the model equations reflect a combined effect of the several factors discussed above on electricity usage in 1999-2004. Coefficients of the annual trend variables included in the long-term energy sales model equations capture a long-term trend of the combined effect, which was reflected in the energy sales forecasts for 2005-2013.

AG#1-3

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q3. On page 5-32 of Volume I, it is stated that an Inlet Air Cooling system is being added to Brown units 8-11. Please state why a similar system is not being added to Brown units 6 and 7, since they are to be dispatched more often, according to Table 4.8.(3)(b)12.

A3. See the response to PSC Question 16.

AG#1-4

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q4. On page 5-35 of Volume I, a September 27, 1999, IRP for combustion turbines is described. Without revealing any confidential information, please provide the results of this IRP, and whether any bids were found to be acceptable and will be exercised.

A4. The responses to the Companies RFP for CTs contained only budgetary estimates for price and thus no direct purchases were made from the RFPs. In general, the price for CTs is similar to those seen in the April 1999 RFP for CTs and delivery times are still relatively long. For additional information please see the response to PSC Question 2.

AG#1-5

AG#1-6

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q5. On page 6-15 of Volume I, an Ohio Falls evaluation is mentioned. Please provide the results of that evaluation.

A5. See the response to PSC Question 11.

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q6. On page 7-33 of Volume I, Table 7.(2)(h)-2 presents historic electric appliance saturation's for KU. Please provide a similar historic saturation summary for LG&E.

A6. LG&E's saturation data is calculated using a composite saturation rate that considers the number of individual units of the appliance within the household. KU's saturation data is calculated as a ratio of the number of customers who indicate ownership of the appliance over the total number of customers.

Appliance	**1980**	**1981**	**1984**	**1986**	**1988**	**1990**	**1993**	**1995**
Refrigerator	116%	116%	119%	122%	123%	125%	119%	146%
Freezer	40%	38%	43%	42%	42%	42%	45%	*
Color TV	125%	130%	134%	147%	164%	190%	207%	194%
Black & White TV	124%	126%	52%	54%	44%	42%	32%	19%
Video Recorder	-	-	-	-	61%	82%	91%	118%
Home Computer	-	-	-	13%	17%	18%	21%	34%
Electric Range	49%	51%	63%	61%	65%	64%	65%	71%
Microwave Oven	-	-	46%	61%	80%	90%	91%	95%
Dishwasher	25%	30%	48%	47%	51%	52%	51%	53%
Clothes Washer	92%	93%	82%	86%	87%	91%	92%	85%
Elec. Clothes Dryer	43%	47%	53%	53%	56%	69%	71%	62%
Elec. Water Heater	16%	21%	20%	19%	22%	20%	25%	29%
Dehumidifier	-	-	18%	13%	14%	15%	16%	17%
Air Conditioning								
Total	99%	100%	117%	113%	119%	118%	116%	122%
Central	51%	51%	64%	66%	72%	75%	77%	78%
Heat Pump	-	-	-	-	-	-	-	8%
Room	48%	49%	53%	47%	47%	43%	40%	36%
Households w/o A/C	16%	15%		10%	5%	5%	6%	3%
Electric Primary Heating System	7%	9%	15%	18%	17%	14%	14%	23%

* Due to the similarity of refrigerators and freezers, the 1995 survey question combined them.

AG#1-7

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Gregory B. Fergason

Q7. On page 8-81 of Volume I, future DSM programs are discussed:

a. Have these programs been presented to and approved by the LG&E DSM Collaborative? If not, do you intend to get approval for the programs from the Collaborative?

b. Please provide the avoided costs, based on the current IRP, that are used to calculate the benefit of DSM programs. Please also provide the calculations, assumptions and workpapers used to develop these rates.

c. Please provide the avoided costs, based on the current IRP, that are offered to Qualifying Facilities. If they are different than those used in the DSM analysis, please explain why they are different.

A7. a. No. The Companies have made no decisions with regard to future Collaborative activities.

b. All the work papers are included in Section IV of Volume III. The avoided costs are attached.

c. The avoided costs used to screen DSM programs is based upon the same information and analysis that the rates offered to Qualifying Facilities through the co-generation rates except with more detail to give the DSM programs the benefit of hourly reduction in generation.

	Average of Hourly Marginal Cost Used in DSManager ($/MWh)	Levelized Avoided Capacity Cost ($/kw-yr)
2000	12.15	
2001	13.27	47.12
2002	14.05	
2003	14.89	
2004	14.27	
2005	15.03	
2006	16.11	
2007	17.05	
2008	19.27	
2009	19.53	
2010	21.35	
2011	22.67	
2012	24.06	
2013	25.28	
2014	27.56	
2015	29.76	
2016	31.52	

AG#1-8

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q8. In Volume I, on page 8-101 of the IRP, reference is made to LG&E/KU companies' participation in the Ohio Valley Electric Corporation (OVEC). With respect to that participation, please supply the following:

a. Percent of participation and associated number of Megawatts for KU and for LG&E.
b. Number of Kilowatt-hours sold to OVEC by LG&E/KU for each of the last 5 years.
c. Number of Kilowatt-hours bought by OVEC from LG&E/KU for each of the last 5 years.
d. In December 1999, the United States Enrichment Corporation's President William Timbers stated that his company is "analyzing whether to shut down *one* of its two production plants", and that upgrades were being made to the Paducah plant to match the capabilities of the Piketon plant (the Courier-Journal, "Uranium operator could shut down 1 of its 2 plants", December 12, 1999). Has LG&E/KU included in the IRP the very real possibility that the Piketon plant may be shut down in the near future and that LG&E/KU's OVEC capacity may become available for LG&E/KU's use?

A8. a. The Power Participation Ratio as defined in the Inter-Company Power Agreement with OVEC for KU and LG&E is 2.5% and 7.0%, respectively. No firm capacity is obtained from the OVEC agreement because the capacity is used to serve OVEC's contract with the Department of Energy.

b. The table below lists the energy sold to OVEC for the period 1995-1999. The information is based upon the Companies FERC form 1.

	Energy Sold to OVEC (MWh)	
	KU	**LG&E**
1995	8,983	144,947
1996	4,561	328,523
1997	1,076	17,754
1998	17,985	29,413
1999	57,846	65,325

c. We assume the question meant to ask for energy purchased. The table below lists the energy purchased from OVEC for the period 1995-1999. The information is based upon the Companies FERC form 1.

	Energy Purchased from OVEC (MWh)	
	KU	**LG&E**
1995	34,491	99,427
1996	36,544	297,309
1997	35,422	17,700
1998	283,104	407,315
1999	413,975	352,938

d. No.

AG#1-9

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q9. On page 8-106 of Volume I, the IRP outlines a number of proposals to reduce carbon dioxide emissions. Please explain in detail how this IRP prepares KU and LG&E for future mandated reductions in carbon dioxide emissions that are likely.

A9. As part of the Analysis of Supply-Side Technology Alternatives included in Volume III of the IRP, the Companies performed a sensitivity analysis to evaluate the impact of a carbon tax on the outcome of the screening analysis. This sensitivity analysis did not change the outcome of the screening analysis. Therefore, the assumed level of carbon tax would not have an impact on the outcome of the Companies IRP. However, the Companies are continually evaluating its resource plans and will be able to adjust its plans in the event that legislation for the reduction of carbon dioxide emissions is implemented.

AG#1-10

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Caryl M. Pfeiffer

Q10. On page 8-106 of Volume I, the IRP outlines a proposal to establish an "energy portfolio standard" requiring minimum use of renewable resources:

a. What is LG&E's current reliance on renewable resources?
b. What is KU's current reliance on renewable resources?
c. Please explain in detail how this IRP is preparing LG&E/KU for a possible future requirement of minimum use of renewable resources?

A10. a. The Companies' reliance on renewable resources (it is assumed that hydro is included as a renewable resource) can be best shown by reviewing Table 8.(4)(b) on page 8-92 of Volume I of the IRP.

b. See response to "a" above.

c. The IRP did not consider the proposal to establish an "energy portfolio standard".

AG#1-11

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q11. On page 8-120 of Volume I, the limitation of only one IPP Hydro purchase is mentioned. Please explain why this constraint is included, considering the large number of dams on the Ohio river that have yet to have hydro added to them.

A11. At the time the Companies' IRP was being prepared, only one proposal had been received for a hydro facility. This project was representative of a hydro facility and utilized a technology that was lower cost than a traditional hydro facility. If this facility was not selected in a least cost plan then modeling additional hydro facilities would not add value to the integrated resource plan analysis.

AG#1-12

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q12. On page A-5 and A-6 of Volume II, historic peak load data is provided through 1998. Please provide this same information for each table for the year 1999.

A12. Summer Peak Demand

Year	Month	Date	Hour Ending	Day	MW	MW w/o Interrution	TempPK	CDH	DewTemPK	24AvgTmp	CDD24	THIPK	24AvgTHI
1999	7	30	1500	FRI	2,612	2,701	105	40	72	91.5	36.5	89.7	82.4

Winter Peak Demand

Year	Month	Date	Hour Ending	MW	TempPK	HDH	WindPK (meter/sec.)	WchillPK	24AvgTmp	HDD24	WindPK (Knot or MPH)
1999	1	4	1900	1,665	11	54	6	2,982.6	14	51	14

AG#1-13

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q13. On page B-3 of Volume II, projected air conditioning saturation exceeds 99% in 2013.

a. The projected saturation of air conditioners is much higher than penetration of telephones, which are considered a necessity. Please provide evidence that this high saturation is possible.
b. If air conditioning saturation approaches 99%, should it be classified as a necessity rather than as a luxury in this region of the country?

A13. a. The composite residential air conditioning (A/C) saturation rate provided in Page B-3 of Volume II is not a simple A/C saturation rate which is a ratio of the number of residential customers with A/C to total number of residential customers. The composite saturation rate is estimated with the appliance survey data on type (window vs. central) and number of A/C units owned by local households. The composite rate is calculated by dividing a weighted number of A/C units in the area by total number of residential customers. The weighted number of A/C units is counted by giving a window unit a 1/3 weight of a central unit, taking account of difference in average capacity size and energy intensity. Depending on how many households own more than one central A/C unit, the composite saturation rate can exceed 100% while it is impossible to have a simple A/C saturation rate higher than 100%. For the LG&E service area, it is estimated that about 3% of the households own two or more central A/C units and about 4% of the households own three or more window A/C units. Considering the residential customers with multiple A/C units, the composite saturation rate is likely to be higher than a simple rate. The penetration level of telephones referred in the question above implies a simple saturation rate and is not directly comparable with a composite rate.

b. The potential maximum for a composite A/C saturation rate is not known, but could be well over 100%. Therefore, a saturation rate close to 100% does not necessarily indicate that air conditioning is a necessity to every household. In the LG&E service area, about 3-5% of the residential customers live without A/C.

AG#1-14

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: H. Bruce Sauer

Q14. In Volume II, Appendix 2, page 23, projections for the all-electric FERS class is given. Please provide a projection of a breakdown of these customers into resistance heat customers, air source heat pump customers, and ground source heat pump customers.

A14.

FERS FORECAST
BY HEATING TYPE

Years	Resistance	Air Source Heat Pump	Electric Room	Ground Source Heat Pump	Other	Total
1999	71,912	59,422	30,823	3,488	8,902	143,724
2000	73,891	63,180	31,515	3,584	8,839	149,493
2001	75,880	66,957	32,208	3,679	8,776	155,292
2002	77,749	70,725	32,879	3,775	8,713	160,962
2003	79,598	74,450	33,507	3,880	8,651	166,579
2004	81,364	78,036	34,102	3,980	8,590	171,969
2005	82,231	80,099	34,346	4,034	8,528	174,892
2006	83,448	82,746	34,725	4,106	8,468	178,767
2007	84,588	85,271	35,073	4,174	8,408	182,441
2008	85,677	87,701	35,399	4,240	8,348	185,965
2009	86,740	90,089	35,714	4,304	8,289	189,421
2010	86,792	92,456	36,023	4,367	8,230	192,845
2011	88,798	94,741	36,312	4,428	8,171	196,139
2012	89,788	96,997	36,594	4,488	8,113	199,386
2013	90,754	99,211	36,866	4,546	8,056	202,567

AG#1-15

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q15. In Volume III, Section III, in Appendix A - Table 2 outlines generator data. This chart shows that the Tyrone, Pineville and Green River units range in age around 50 years. In the past, KU stated an expected life of generating units of 54 years. Does KU intend to retire or repower any of the very old units in the near future? If so, please provide details. If not, please provide the expected life of these units.

A15. See the response to PSC Question 24.

AG# 1-16

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Gregory B. Fergason

Q16. In Volume III, Section IV, in Phase I screening, a large number of DSM programs just barely missed the 3.0 cutoff. Considering that both the assignment of ratings and the cutoff point were subjective judgements, please explain why these programs that just barely missed the cutoff weren't also given a Phase II analysis.

A16. The purpose of screening the DSM options is two-fold: 1) to learn more about the DSM technologies available, 2) to narrow the number of alternatives to a manageable level before competing with the alternatives that passed the supply-side screening.

AG#1-17

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Gregory B. Fergason

Q17. In Volume III, Section IV, page 13 states that DSM measures are less attractive since real energy costs are decreasing. Isn't it true that the avoided costs by which the benefits of DSM programs are measured have been increasing recently, as market prices for power have been increasing?

A17. Market prices have increased however, the sentence referred to was related to retail rates which have been stable and, in the recent past, moved downward.

AG#1-18

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Caryl M. Pfeiffer

Q18. On page 42 of Section V of Volume III of the IRP, Carbon Dioxide impacts are analyzed. For each of the last 11 years, 1989-1999, please supply the following:

a. Total carbon dioxide emissions associated with supplying LG&E and KU's internal energy demand, including municipals.
b. Total carbon dioxide emissions associated with selling power off-system.
c. Total carbon dioxide emissions from LG&E/KU generators (thus including off-system sales but excluding emissions associated with energy purchased to supply internal energy demand).

A18. a. Carbon dioxide is measured at the output of the generating unit and is not differentiated between the type of the ultimate consumer. Only total CO_2 emissions are available from the generating units therefore, historical emissions include those associated with meeting internal demand and off-system sales.

b. See response "a".

c.

1989	23,828,048	tons
1990	25,034,149	tons
1991	26,401,852	tons
1992	25,987,166	tons
1993	28,534,047	tons
1994	28,784,046	tons
1995	28,472,055	tons
1996	31,486,609	tons
1997	30,879,477	tons
1998	32,878,326	tons
1999	33,778,361	tons

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Caryl M. Pfeiffer

Q19. On page 42 of Section V of Volume III of the IRP, Carbon Dioxide impacts are analyzed. For each of the years in the IRP planning period, through 2013, and based on the base plan in the IRP, please supply the following:

a. Total carbon dioxide emissions associated with supplying LG&E and KU's internal energy demand, including municipals.
b. Total carbon dioxide emissions associated with selling power off-system.
c. Total carbon dioxide emissions from LG&E/KU generators (thus including off-system sales but excluding emissions associated with energy purchased to supply internal energy demand).

A19. a.

2000	29,622,333	tons
2001	30,439,904	tons
2002	31,260,046	tons
2003	31,665,710	tons
2004	32,482,900	tons
2005	32,990,895	tons
2006	33,611,341	tons
2007	34,232,091	tons
2008	35,032,804	tons
2009	35,528,760	tons
2010	36,261,022	tons
2011	36,801,329	tons
2012	37,450,749	tons
2013	37,851,964	tons

b. Off-system sales projections are not used in the development of the Integrated Resource Plan.

c. Off-system sales projections are not used in the development of the Integrated Resource Plan.

AG#1-20

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Lonnie E. Bellar

Q20. In Volume I, Table 8.(4)(b) and Table 8.(4)(c) display forecast energy and fuel use by fuel type for the forecast period. Please provide the same tables with the same type of information for the past 11 years, 1989-1999

A20. The requested forecasted information from the past 11 years is not available. However the same tables with the same type of information from LG&E's 1991 and 1993 and KU's 1991, 1993 and 1996 IRP's are attached.

8.(4)(b)

ANNUAL GENERATION (GWH)

		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1	Total Requirement	9,548	9,636	9,883	10,145	10,327	10,351	10,771	10,910	11,083	11,254	11,438	11,606	11,757	11,757	11,905	12,089
5	Reductions (Additions)	None															

	Source (Fuel type)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
2	Coal	N/A	9,147	9,394	9,647	9,844	10,012	10,130	10,246	10,378	10,542	10,300	10,873	11,035	11,136	11,312	11,481
	Oil	N/A	25	24	27	24	26	26	29	29	30	23	33	34	37	38	39
	Gas	N/A	22	23	24	28	26	28	28	30	32	50	54	56	75	80	87
	Hydro	N/A	407	408	407	407	407	408	407	407	407	408	407	407	407	408	407
3	Utility Purchases	None															
4	Non-Utility Purchases	None															

Annual Sources of Generation (GWH)

		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	Total Requirement	9,756	10,073	10,324	10,579	10,781	10,989	11,182	11,375	11,549	11,727	11,900	12,082	12,254	12,414	12,565	12,717
5	Net DSM Reductions (Additions)	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
2	Coal	N/A	9,685	9,927	10,188	10,363	10,572	10,765	10,940	11,101	11,261	11,418	11,522	11,678	11,813	11,939	12,064
	Hydro	413	356	352	352	349	344	340	336	333	332	328	390	392	390	390	390
	Gas	N/A	10	12	12	12	11	10	44	81	92	104	114	188	215	242	275
	Oil	N/A	1	2	2	1	1	1	6	11	14	16	18	18	22	24	26
3	Firm Utility Purchases	0	0	0	0	14	21	33	18	0	0	0	0	0	0	0	0
4	Firm Non-Utility Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Supplemental Purchases	0	41	61	56	41	38	32	29	22	27	32	36	34	40	46	52
	Supplemental Requirements																
	Pumping	0	0	0	0	0	0	0	0	0	0	0	0	56	66	77	91
	Firm Utility Sales	0	20	30	30	0	0	0	0	0	0	0	0	0	0	0	0

Table 8.(4)(b)

)(b)

KENTUCKY UTILITIES COMPANY

FORECAST ANNUAL GENERATION

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Total Energy Requirements (GWH)	13961	14486	14839	15152	15449	15745	16048	16380	16710	17027	17328	17608	17893	18181	18503	18849

Energy By Fuel Type (GWH)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Coal	12381	12732	12991	13295	12899	13083	13308	13617	13897	14095	14387	14602	14821	15339	15770	16168
Gas	0	8	16	14	9	20	24	26	31	43	53	57	35	16	11	14
Oil	77	23	34	32	32	98	132	159	197	311	409	438	511	347	255	315
Hydro	67	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55

Purchases From Other Utilities (GWH)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
OMU	1475	1756	1757	1732	1704	1401	1457	1450	1454	1438	1346	1380	1379	1355	1341	1230
EEI	103	201	212	262	977	1073	1068	1071	1076	1078	1083	1083	1086	1083	1088	1091
IP				49	54											
Other	59	19	56	37	13	25	13	11	10	18	11	7	20	4	1	2

Purchases From Non-Utility	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

Reductions / Increases In Energy	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

TABLE 8-4(B)
KENTUCKY UTILITIES COMPANY
FORECAST ANNUAL GENERATION

		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	Total Energy Requirements (GWH)	14844	15886	16419	16733	16948	17252	17553	17891	18193	18494	18797	19148	19454	19748	20021	20345

	Energy By Fuel Type (GWH)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
2	Coal	13636	14370	13832	13728	13897	14221	14737	14816	15279	15321	15584	15811	16111	16295	16437	16671
	Gas	0	12	28	70	99	106	145	202	261	297	312	407	417	482	584	733
	Oil	0	33	22	32	32	36	42	53	96	77	100	95	103	127	149	267
	Hydro	63	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55

	Firm Purchases From Other Utilities (GWH)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
3	OMU	1764	1459	1613	1755	1760	1724	1451	1531	1363	1626	1586	1592	1584	1590	1588	1379
	EEI	148	482	1191	1077	1067	1093	1103	1107	1101	1082	1126	1136	1131	1136	1142	1146
	IP	0	135	41													
	Other	122	38	10	6	5	3	3	4	6	2	3	5	2	4	3	6

	Purchases From Non-Utility	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
4		None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

	Reductions / Increases In Energy (GWH)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
5		0	0	4	7	9	13	16	20	25	29	34	38	43	48	54	59

Table 8-4(b)

Kentucky Utilities Company

Forecast Annual Energy

1

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Total Energy Requirements (GWH)	17,191	17,757	18,427	19,118	19,674	20,067	20,367	20,701	21,099	21,538	22,037	22,534	23,004	23,426	23,843	24,245

2

Energy by Fuel Type (GWH)	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Coal	15,113	15,446	15,949	16,430	16,771	17,009	17,120	17,240	17,384	17,428	17,572	17,778	18,037	18,204	18,560	18,589
Gas	23	104	122	223	321	408	564	630	752	964	1,211	1,434	1,768	1,916	1,845	2,165
Oil	22	28	36	50	71	78	105	125	154	179	250	295	338	353	429	479
Hydro	65	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63

3

Firm Purchases From Other Utilities (GWH)	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OMU	1,436	1,611	1,732	1,726	1,717	1,714	1,525	1,580	1,654	1,648	1,529	1,560	1,385	1,466	1,532	1,527
EEI	1,537	1,346	1,348	1,356	1,362	1,372	1,372	1,373	1,370	1,373	1,347	1,339	1,348	1,359	1,351	1,359
Virginia Power	0	0	8	2	0	0	0	0	0	0	0	0	0	0	0	0
OVEC	34	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
Other	242	51	56	89	108	123	131	101	44	22	5	4	3	4	3	2

4

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases From Non-Utility	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

5

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Reductions / Increases in Energy (GWH)	Incorporated into Total Energy Requirements															

Note: 1995 numbers are actuals

AG#1-21

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Caryl M. Pfeiffer

Q21. On page 25 of Section V of Volume III of the IRP, Nitric Dioxide (NOx) emissions are mentioned. For each of the last 11 years, 1989-1999, please supply the following:

a. Total NOx emissions associated with supplying LG&E and KU's internal energy demand, including municipals.
b. Total NOx emissions associated with selling power off-system.
c. Total NOx emissions from LG&E/KU generators (thus including off-system sales but excluding emissions associated with energy purchased to supply internal energy demand).

A21. a. NOx is measured at the output of the generating unit and is not differentiated between the type of the ultimate consumer. Only total NOx emissions are available from the generating units therefore, historical emissions include those associated with meeting internal demand and off-system sales.

b. See response to "a".

c.

1989	87,570	tons
1990	91,883	tons
1991	90,808	tons
1992	89,302	tons
1993	81,280	tons
1994	77,953	tons
1995	73,857	tons
1996	72,622	tons
1997	70,559	tons
1998	73,752	tons
1999	71,382	tons

AG#1-22

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY
CASE NO. 99-430

Response to First Data Request of AG Dated January 25, 2000

Responding Witness: Caryl M. Pfeiffer

Q22. On page 25 of Section V of Volume III of the IRP, Nitric Dioxide (NOx) emissions are mentioned. For each of the years in the IRP planning period, through 2013, and based on the base plan in the IRP, please supply the following:

a. Total NOx emissions associated with supplying LG&E and KU's internal energy demand, including municipals.
b. Total NOx emissions associated with selling power off-system.
c. Total NOx emissions from LG&E/KU generators (thus including off-system sales but excluding emissions associated with energy purchased to supply internal energy demand).

A22. a.

2000	66,386	tons
2001	67,846	tons
2002	69,559	tons
2003	70,767	tons
2004	72,436	tons
2005	73,264	tons
2006	74,470	tons
2007	75,858	tons
2008	77,280	tons
2009	78,208	tons
2010	79,808	tons
2011	80,938	tons
2012	81,517	tons
2013	82,663	tons

b. Off-system sales projections are not used in the development of the Integrated Resource Plan.

c. Off-system sales projections are not used in the development of the Integrated Resource Plan.