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May 13, 2005

Elizabeth O'Donnell, Executive Director
Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40601

Re: ***AN ASSESSMENT OF KENTUCKY'S ELECTRIC GENERATION, TRANSMISSION, AND DISTRIBUTION NEEDS***
ADM. CASE NO. 2005-00090

Dear Ms. O'Donnell:

Kentucky Utilities Company files herewith an original and ten (10) copies of its response to the 2nd Data Request of the Commission Staff dated April 27, 2005, in the above-referenced case.

Should you have any questions concerning the enclosed, please do not hesitate to contact me.

Very truly yours,

John Wolfram
Manager, Regulatory Affairs

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

AN ASSESSMENT OF KENTUCKY'S ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION NEEDS	))))	ADM. CASE NO. 2005-00090

RESPONSE OF KENTUCKY UTILITIES COMPANY TO SECOND REQUEST OF COMMISSION STAFF DATED APRIL 27, 2005

FILED: MAY 13, 2005

KENTUCKY UTILITIES COMPANY

RESPONSE TO SECOND REQUEST OF COMMISSION STAFF
DATED APRIL 27, 2005
IN ADMINISTRATIVE CASE NO. 2005-00090

Question No. 1

Witness: Martyn Gallus / John P. Malloy

Q-1. Explain the how the development of Regional Transmission Organizations ("RTO") and the possibility of greater competition in the wholesale market has impacted your planning decisions. Also, provide a discussion of how RTOs have affected your strategy regarding making off-system sales and your ability to arbitrage.

A-1. The development of RTOs has not impacted the Companies' resource planning process to date. As described in the Companies' Integrated Resource Plan ("IRP"), and in numerous proceedings in which the Companies sought a Certificate of Public Convenience and Necessity ("CCN") for generation resources, the Companies determine their needs and then follow a well-established process for determining the least-cost method of meeting that need. The traditional Request for Proposal ("RFP") process is used to identify purchased power alternatives that are then evaluated, along with generation construction alternatives, on the basis of lowest net present value of revenue requirements. This process remains effective in the RTO environment.

Furthermore, it is not clear that the development of RTOs and centralized regional markets has increased competition in the wholesale market. The Companies have expressed this and other concerns in this regard in the Commission's investigation into the Companies' membership in the MISO in Case No. 2003-00266. These concerns have been heightened since the implementation of the MISO Day 2 markets on April 1, 2005.

Finally, the Companies' business interest regarding making off-system sales has not changed due to RTO development, but the mechanics of how the Companies make off-system sales has changed with the implementation of the MISO Day 2 markets. Prior to that implementation, the Companies' participated in off-system sales in the over-the-counter market; since April 1, 2005, the Companies have participated in the centralized energy market administered by MISO.

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Question No. 2

Witness: John P. Malloy

Q-2. Describe the manner in which increasing prices for coal and natural gas have impacted your generation resource decisions. Include in the response a discussion of how the increase in prices has impacted your consideration of new generation technologies.

A-2. The gap between coal and gas prices has increased even in the face of escalating coal prices. Generation resource decisions are based on lowest total revenue requirements. Currently environmental regulations (including market prices for emission allowances) in conjunction with the gaps in fuel pricing are driving consideration of new technologies. Consideration of new technologies is discussed at length in the recently filed report titled *Analysis of Supply-Side Technology Alternatives* (November 2004) contained in Volume III, Technical Appendix, of the Companies' 2005 Integrated Resource Plan, as filed with the Commission in Case No. 2005-00162.

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Question No. 3

Witness: John P. Malloy

Q-3. Explain to what extent the availability or possible availability of merchant power has impacted your generation resource decisions.

A-3. When the Companies forecast a resource need, "Requests for Proposals" are solicited. All responding parties, merchant or otherwise, are evaluated for the determination of the least cost resource, as described in response to Question No. 1. This methodology is consistent with historical practices which have been the subject of Commission review and oversight.

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Question No. 12

Witness: David S. Sinclair

Q-12. Refer to Items 5 and 7 of KU's response to the Commission's March 10, 2005 Order. During the period 2000 – 2004, KU's native load weather-normalized peak summer demand increased by less than .2 percent annually and was less in 2003 and 2004 than the 3,870 Mw demand level of 2002 (3,800 in 2004). With this background, identify and describe the factors which contribute to KU's 2005 demand being forecast at 4,067 Mw, with an average growth of 95 Mw, or 2.0 percent, annually, for the period 2005 – 2019.

A-12. KU's projection of system peak demand is consistent with its forecast of energy requirements. The relationship between actual peak demand and actual annual energy requirements (expressed as system load factor) fluctuates from year to year due to changes in weather and business conditions. Therefore, the Company eliminates these yearly fluctuations by using an average hourly load shape (for each month) based on the actual hourly load experienced in the last ten years. Since peak demand is merely the hour with the highest energy requirement in the course of the year, the system peak demand is expected to grow at roughly the same rate as the rest of the hours in the year.

As shown in my response to Question 4 of the March 10, 2005 Order, total native load sales – weather-normalized - increased from 18,939 MWh in 2000 to 20,534 MWh in 2004, an average annual increase of 2.0%. This increase was recorded despite the impact of the economic slowdown in 2001, which resulted in the only annual decline in (weather-normalized) sales in the last ten years. Over the long term term, we assume normal economic growth, which results in an increase in energy sales of around 2.0% annually over the forecast horizon. Therefore, KU's system peak demand is expected to grow at a similar rate.

The following attachment, as included in the "Energy Requirements and Demand Forecast" technical appendix to the Companies' 2005 IRP filing (Vol II), outlines the process of converting the monthly energy forecast to a chronological projection of hourly loads (including the system monthly and annual peaks).

PEAK LOAD FORECAST PROCESS

Energy Sales Forecast
Monthly aggregate energy sales, by company

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System Energy Requirements
Monthly aggregate sales + losses

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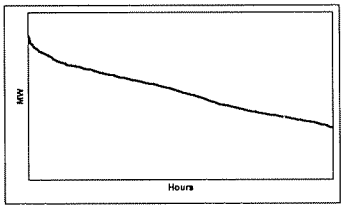
Load Duration Curve

For each utility (separately), apply representative monthly load shapes (load duration curves) to monthly energy data to derive hourly loads



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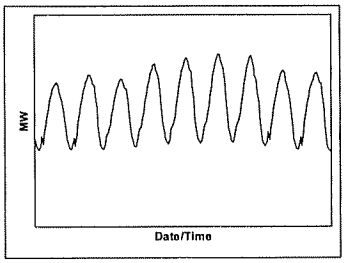
Chronological Load Curve

Rearrange hourly loads in chronological order by application of appropriate historical load curve for each month of forecast



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Combined System Load Curve

KU and LG&E load curves added to produce coincident load curve for combined system

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Question No. 13

Witness: John P. Malloy

Q-13. Refer to Item 10(e) of KU's response to the Commission's March 10, 2005 Order.

a. KU shows natural gas as the type of fuel for each unit at Haefling. However, EIA 2003 data shows fuel oil as the primary fuel at Haefling with natural gas as secondary. Explain which is accurate.

b. KU shows natural gas as the type of fuel for units 8, 9, 10, and 11 at E.W. Brown. EIA 2003 data also shows natural gas as the primary fuel for these units with fuel oil as secondary. Explain which is accurate.

A-13.

a. In Item 10(e) of KU's response to the Commission's March 10, 2005 Order, the data submitted only reflected the primary fuel for the units. The EIA data from 2003 showed fuel oil as primary fuel at the Haefling station. These units are capable of burning either natural gas or fuel oil. Currently, natural gas is the primary fuel due to the higher prices of fuel oil, and is reflected in the 2004 EIA data.

b. In Item 10(e) of KU's response to the Commission's March 10, 2005 Order, the data submitted only reflected the primary fuel for the units. The EIA data from 2003 showed natural gas as primary fuel for Brown Units 8-11, with fuel oil listed as a secondary fuel. These units are capable of burning either natural gas or fuel oil. Currently, natural gas is the primary fuel due to the higher prices of fuel oil.

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Question No. 16

Witness: John P. Malloy

Q-16. Refer to Items 8 and 9 of the responses to the Commission's March 10, 2005 Order. With a reserve margin of 12 to 14 percent recommended for planning purposes, explain why, based on planned resource acquisitions, the combined reserve margin for LG&E and KU, for the 2005 – 2025 period, is greater than 14.0 percent in 20 of 21 years and greater than 15.0 percent in 17 of 21 years.

A-16. The reserve margin target established in the Companies' 2005 IRP is 14 percent. The reserve margin target is the *minimum* reserve margin that the Companies utilize for modeling purposes and long-term resource planning. The data provided in response to Item 9 referenced above was based on the assumption that the resources called for in the IRP are acquired. Since the resource acquisitions within the planning period are block additions (*i.e.* the resources have set capacity ratings), it is reasonable to expect the reserve margin to exceed the target in the year(s) following the in-service date of a new resource acquisition. The extent to which the Companies exceed the reserve margin target depends on the type and magnitude of the capacity addition. In this instance, the sizing of the added units causes the reserve margin to exceed the target in most years but to decline back to the target over time.