COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	)))	ADMINISTRATIVE CASE NO. 387

<u>O R D E R</u>

Electricity shortages, rolling blackouts, and wholesale price increases of 900 percent[1] -- conditions not traditionally associated with utilities in this country -- have been experienced with all too painful frequency in California during the past 12 months. Insufficient electric generation has resulted in untold damage to California's quality of life and the competitive standing of its businesses, as well as to the state's economy and economic development efforts. While many critics dismiss California's dysfunctional electric market as the result of a flawed restructuring plan, the fact is that adequate generating supplies would have substantially lessened, if not eliminated, the disastrous consequences.

Here in Kentucky, we have historically enjoyed some of the lowest rates for electricity in the nation, along with high quality, reliable service. Our low rates are due substantially to the state's past reliance on coal-fired base load generation owned by the utilities (or their affiliates) serving in Kentucky and sold at cost-of-service rates. In the past few years, utilities have become increasingly reliant on higher cost gas-fired peaking generation and short-term power purchased at market prices that are typically

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[1] California Tackles "Energy Nightmare," <u>USA Today</u>, January 9, 2001.

well above the utility's average embedded cost. While electric restructuring does not appear to be imminent in Kentucky, due in large part to the findings of a joint legislative and executive branch task force that no long-term statewide benefits will result, the issue remains under study.

Even assuming that Kentucky does not embrace electric restructuring, the changing market conditions sweeping the nation are likely to have an impact here. We know from recent events in California that electric shortages and price spikes cannot be contained by artificial boundaries such as state borders. California's electric problems have caused most of the western states to incur increased wholesale power prices and decreased generation reserves. Most of the states that border Kentucky have either adopted electric restructuring or are seriously considering adopting restructuring. The resulting impacts on wholesale electric markets, as well as the price of natural gas, will likely be felt by the utilities and ratepayers in Kentucky.

To the extent that electric demand exceeds supply in this region of the country, prices will increase and utilities in Kentucky may be inclined to make more sales to out-of-state buyers. A limited number of Kentucky's industrial customers have rates that track wholesale power prices, and these customers are already faced with paying substantially higher rates or curtailing their production. Restructuring in neighboring states raises profound issues relative to the impact on Kentucky's generation and the adequacy of that generation. Will Kentucky's electric utilities export greater amounts of their low-cost power, further reducing the already dwindling reserves available to native load customers? As retail competition increases in neighboring states to the north, will more power purchases from lower-cost southern states put pressure on Kentucky's transmission grid? Will the recent upward trend in wholesale power prices continue, rendering unwise and costly any long-term policy of favoring purchased power over constructing generation? These are just a few of the questions facing Kentucky's electric utilities.

The Commission believes it is essential to the well-being of the state's population and the economy that electric generation continue to be available at reasonable costs to meet the state's existing and future needs. Recent events, including both California's generation shortages and the nationwide spike in natural gas prices, have led the Commission to conclude that a formal review should be conducted to ensure that Kentucky continues to have adequate electric generation and reliable transmission at reasonable costs to meet its future needs. We hope to find answers to the questions raised herein, as well as to those that develop during the course of this proceeding. The issues to be examined include the appropriate level of reliance on purchased power, the appropriate reserve margins to meet existing and future electric demand, the impact of recent spikes in natural gas prices on utility planning strategies, and the adequacy of Kentucky's transmission facilities.

The four major electric generating utilities, Kentucky Power Company d/b/a American Electric Power, East Kentucky Power Cooperative, Kentucky Utilities Company, and Louisville Gas and Electric Company, along with Big Rivers Electric Corporation and The Union Light, Heat and Power Company, are made parties to this proceeding. Although the Commission has no jurisdiction over city-owned electric systems, the Tennessee Valley Authority ("TVA"), the TVA distribution cooperatives serving Kentucky, or independent power producers, representatives from those entities and other interested parties are invited and encouraged to intervene and participate. Each jurisdictional utility made a party to this case will be required to file testimony. At a minimum, testimony should address the questions and other issues set forth in this Order. To ensure that the record is as comprehensive as possible, we strongly encourage non-jurisdictional utilities and all other stakeholders to file testimony. In addition, the Commission intends to invite experts to discuss relevant issues including, but not limited to, Kentucky's economic and population growth. Attached to this Order as Appendix A is a procedural schedule. Attached as Appendix B is a data request to which the six utilities cited above are to respond by July 17, 2001 in accordance with the procedural schedule. Other participants are encouraged to respond to Appendix B to the extend the information requested is available.

IT IS THEREFORE ORDERED that:

1. A review to ensure that Kentucky continues to have adequate electric generation and reliable transmission at reasonable costs to meet its future needs is hereby instituted. The six jurisdictional electric utilities identified herein shall be parties to this proceeding. Other interested parties, including city-owned electric systems, the TVA, the TVA distribution cooperatives serving Kentucky, independent power producers, consumer advocates and retail customers, may intervene and participate.

2. The six jurisdictional electric utilities herein shall file responses to the information requests contained in Appendix B. The original and 10 copies of the responses shall be filed with the Commission by July 17, 2001. Other parties are encouraged to respond to Appendix B to the extent the information is available.

3. All requests for intervention shall be made within 30 days of the date of this Order. Any party that chooses not to intervene will be given the opportunity to file written comments or to offer comments at the first public hearing.

Done at Frankfort, Kentucky, this 2nd day of July, 2001.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN ADMINISTRATIVE CASE NO. 387 DATED July 2, 2001

AEP-KY, Big Rivers, EKPC, KU, LG&E and ULH&P shall file responses to the requests for information in Appendix B no later than 07/17/01

AEP-KY, Big Rivers, EKPC, KU, LG&E and ULH&P shall file testimony no later than 07/31/01

First Public Hearing is to begin at 9:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the Commission's offices at 211 Sower Boulevard, Frankfort, Kentucky, for the purpose of receiving testimony from expert witnesses on economic and population growth, as well as other issues, and receiving public comments .... To be scheduled

The Commission's supplemental requests for information to AEP-KY, Big Rivers, EKPC, KU, LG&E and ULH&P shall be filed no later than .... To be scheduled

Second Public Hearing is to begin at 9:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the Commission's offices at 211 Sower Boulevard, Frankfort, Kentucky, for the purpose of cross-examination of witnesses of AEP-KY, Big Rivers, EKPC, KU, LG&E and ULH&P.................... To be scheduled

Intervenor testimony, if any, shall be filed no later than .... To be scheduled

Third Public Hearing is to begin at 9:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the Commission's offices at 211 Sower Boulevard, Frankfort, Kentucky, for the purpose of receiving testimony from Intervenors............... To be scheduled

Briefs of all parties shall be filed by 10/15/01

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN ADMINISTRATIVE CASE NO. 387 DATED

1. Provide actual and weather-normalized energy sales per month for calendar years 1999 and 2000. Sales should be disaggregated between native load and off-system sales with native load sales reported by customer classification and off-system sales further disaggregated into full requirements sales, firm capacity sales, and non-firm or economy energy sales. Off-system sales should be further disaggregated to show separately those sales in which your company acts as a reseller, or transporter, in a power transaction between two or more other parties.

2. Provide actual and weather-normalized monthly coincident peak demands for calendar years 1999 and 2000. Demands should be disaggregated into (a) native load demand, both firm and non-firm; and (b) off-system demand, both firm and non-firm.

3. Provide a summary of monthly power purchases for calendar years 1999 and 2000. Purchases should be disaggregated into firm capacity purchases required to serve native load, economy energy purchases, and purchases in which your company acts as a reseller, or transporter, in a power transaction between two or more other parties. Provide the average monthly cost per megawatt-hour for each purchase category.

4. Based on the most recent available forecast, provide base case demand and energy forecasts and high case demand and energy forecasts for the period 2001 through 2010. The information should be disaggregated into (a) native load, identifying both firm and non-firm demand; and (b) off-system load, identifying both firm and non-

firm demand. Provide all inputs, factors and assumptions upon which both forecasts are based and their sources (United States Census Bureau, Data Resources International, developed in-house, etc.). Identify the models used in preparing the forecasts and the source or supplier of each model.

5. Provide the target reserve margin currently used for planning purposes, stated as a percentage of demand, and a summary of the most recent reserve margin analysis or study performed on behalf of your company. If this target reserve margin has changed in the last 3 years, provide the prior target reserve margin and explain in detail the reasons for the change.

6. For the period 2001 through 2010, provide projected reserve margins stated in megawatts and as a percentage of demand. Identify projected deficits and current plans for addressing these. For each year provide by month the level of firm capacity purchases projected to meet native load demand, including your best estimates of the cost of such purchases.

7. Identify, by date and hour, all incidents from January 1, 1999 to the present date, when your actual reserve margin was less than your target reserve margin. Show the amount of capacity resources that were available, the actual demand on the system, and the reserve margin, stated in megawatts and as a percentage of demand.

8. Identify all utilities with which your utility is interconnected and the transmission capacity at all points of interconnection.

9. Identify any areas on your system where capacity constraints, bottlenecks, or other transmission problems have been experienced from January 1, 1999 until the

present date. Identify all incidents of transmission problems by date and hour, with a brief narrative description of the nature of the problem.

10. Provide details of any planned base load or peaking capacity additions to meet native load requirements for years 2001 through 2010. Include all capacity additions by the utility, as well as those by an affiliate, if constructed in Kentucky or intended to meet load in Kentucky.

11. Provide details of any planned transmission capacity additions for the 2001 through 2010 period. If the transmission capacity additions are for existing or expected constraints, bottlenecks, or other transmission problems, provide the link between the addition and the problem.

12. Explain whether any of the transmission capacity additions discussed in response to Item No. 11 are expected to go beyond "ordinary course of business" construction, such that they would require formal Commission approval.

13. Provide details of scheduled outages or retirements of generation capacity for the 2001 through 2010 period.

14. Provide details of all forced outages occurring during 1999 and 2000.

15. Provide details of any temporary or permanent reductions in utilization of generation capacity due to Clean Air Act compliance during 1999 or 2000. Also explain any forecasted reductions during the 2001 through 2010 period.

16. Provide copies of any reports prepared by the utility or for the utility that analyze the capabilities of the transmission system to meet present and future needs for import and export of capacity.

17. If your current plans for addressing projected capacity deficits include the addition of gas-fired generation, explain the extent to which recently-high natural gas price levels have been factored into these plans, and how those high prices may have altered the results of previous plans.

18. Provide the following transmission energy data for the 1999 and 2000 actual periods and the forecast for the years 2001 through 2010.

a. Total energy received from all interconnections and generation sources connected to your transmission system.

b. Total energy delivered to all interconnections on your transmission system.

c. Peak load capacity of your transmission system.

d. Peak demand for summer and winter seasons on your transmission system.

19. Provide details of the ability of your transmission system to provide power interchange with interconnected systems.

20. Provide details, including a diagram of the import and export transfer capabilities, of your transmission system.